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MFN 10-089 Revision 1 Docket No. 52-010

March 24, 2010

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

Subject: **Revised Response to NRC RAI Letter No. 409 Related to ESBWR Design Certification Application – DCD Tier 2 Section 10.2 – Steam and Power Conversion System; RAI Number 10.2-18 S03**

The purpose of this letter is to submit the GE Hitachi Nuclear Energy (GEH) revised response to the U.S. Nuclear Regulatory Commission (NRC) Request for Additional Information (RAI) letter number 409 sent by NRC letter dated February 18, 2010 (Reference 1). Reference 2 transmitted GEH's original response to RAI Number 10.2-18 S03. Reference 3 and 4 transmitted staff concerns after reviewing Reference 2. A revised response to RAI 10.2-18 S03 was required to address staff comments after a teleconference to discuss Refereneces 3 and 4. GEH's revised response to RAI 10.2-18 S03 is contained in Enclosure 1. Changes to the RAI response transmitted in Reference 2 are highlighted with rev bars in the right hand column.

Enclosure 2 contains the DCD Tier 1 and Tier 2 changes as a result of GEH's revised response to this RAI. Verified DCD changes associated with this RAI response are identified in the attached DCD markups by enclosing the text within a black box.

If you have any questions or require additional information, please contact me.

Sincerely,

Richard E. Kingston

Richard E. Kingston
Vice President, ESBWR Licensing

References:

1. MFN 10-078 Letter from U.S. Nuclear Regulatory Commission to Jerald G. Head, GEH, *Request For Additional Information Letter No. 409 Related to ESBWR Design Certification* dated February 18, 2010

2. MFN 10-089 Letter from R. E. Kingston, GEH to the U.S. Nuclear Regulatory Commission, *Response to NRC RAI Letter No. 409 Related to ESBWR Design Certification Application – DCD Tier 2 Section 10.2 – Steam and Power Conversion System; RAI Number 10.2-18 S03* dated March 12, 2010

3. Email from Leslie Perkins, NRC, to H.A. Upton, GEH, *RE: 10.2-18* dated March 22, 2010

4. Email from Leslie Perkins, NRC, to H.A. Upton, GEH, *RE: 10.2-18* dated March 19, 2010

Enclosures:

1. Revised Response to NRC RAI Letter No. 409 Related to ESBWR Design Certification Application – DCD Tier 2 Section 10.2 – Steam and Power Conversion System; RAI Number 10.2-18 S03
2. Revised Response to NRC RAI Letter No. 409 Related to ESBWR Design Certification Application – DCD Tier 2 Section 10.2 – Steam and Power Conversion System - DCD Markups for RAI Number 10.2-18 S03

cc:	AE Cubbage	USNRC (with enclosures)
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	eDRF Section	0000-0113-9775 R1 (RAI 10.2-18 S03)

ENCLOSURE 1

MFN 10-089 Revision 1

Revised Response to Portion of NRC Request for

Additional Information Letter No. 409

Related to ESBWR Design Certification Application

DCD Tier 2 Section 10.2 – Steam and Power Conversion System

RAI Number 10.2-18 S03

RAI 10.2.18 S03

The June 7. 2007, response to RAI 10.2-18, SO1, described the diversity that is provided by the primary and emergency overspeed trip systems for the ESBWR turbine. The response indicated that diversity is provided by the design and implementation of the primary and emergency overspeed protection controllers. Because the ESBWR design does not provide the same level of diversity as that called for by SRP Section 10.2 (i.e., one electrical and one mechanical overspeed trip device), it tends to be more subject to common cause and common mode failures than designs that include a mechanical overspeed trip device. Therefore, the following additional information is needed in order for the staff to determine if this deviation from the guidance in SRP Section 10.2 is acceptable:

A. In accordance with 10 CFR 52.47(a)(9), Tier 2 Table 1.9-10 needs to be revised to indicate that a mechanical trip device is not used to provide overspeed protection for the ESBWR turbine and appropriate justification for this deviation needs to be included in Tier 2 Section 10.2. The discussion in the DCD should be sufficient for the staff to find that the level of protection provided by the overspeed protection system for the ESBWR turbine is at least equivalent to the level of protection that would be provided by the diverse design called for by SRP Section 10.2. The following items are pertinent to the staff's evaluation in this regard and should be addressed in this RAI response and reflected in the DCD as appropriate:

1) The description of the turbine overspeed protection system (including air and hydraulic systems/interfaces) need to clearly indicate what parts are shared. For example, shared air and hydraulic dump lines and components such as dump valves need to be described in the DCD.

2) A summary description of the results of a reliability comparison of the two types of overspeed trip systems (or other analysis) that establishes the basis for concluding that the proposed design is at least equivalent to those that include a diverse mechanical overspeed trip device.

3) Factors and assumptions that are important for the analysis referred to in (2) to be valid should be described and COL action items should be established as appropriate to ensure that these considerations are properly implemented and maintained. For example, the amount of time that either the primary or emergency overspeed trip system can be out of service for maintenance is an important factor. Assumptions that periodic inspections, maintenance, testing, and corrective actions will be properly implemented in accordance with GEH and other vendor recommendations in order to ensure reliable performance is another important factor.

4) Common mode and common cause failure considerations that

could prevent the overspeed trip systems from functioning properly and are pertinent to the design should be addressed. For example, the performance of solenoid valves, steam isolation valves, hydraulic systems and air systems have historically been problematic in this regard. Also, the potential for flow restrictions to occur in hydraulic or air system dump lines is of concern (especially in those cases where redundant flow paths are not provided) and need to be addressed. Design and programmatic measures that provide assurance that these common mode and common cause failures are not likely to occur should be described and means to ensure proper implementation by COL applicants should be established as appropriate. **[Note that the proposed DCD markup on the top of Page 10.2-8 needs to include provisions for the extraction non-return valves, and the "augmented inspection program" referred to on Page 10.2-10 needs to be explained (e.g., where is this augmented inspection program specified, the turbine missile probability analysis does not include specific inspection and test requirements for the extraction non-return valves.)]**

- The use of certain materials that are not subject to corrosion, conditioning equipment, desiccants, filters and design standards are examples of design considerations that may be pertinent for addressing common mode and common cause failures.

- Implementation of periodic inspections, maintenance, testing, and corrective actions are examples of programmatic controls that may be applicable for assuring that common mode and common cause failures are prevented from occurring. For example, measures that assure the reliable performance of components and the quality of hydraulic and air systems are pertinent in this regard.

5. Failure of extraction non-return valves to function will tend to increase the probability of turbine overspeed and this is an important consideration in the turbine missile probability analysis that must be completed by COL applicants. Therefore, provisions need to be established and included in the DCD to ensure that COL applicants will properly model the failure of extraction non-return valves in the turbine missile probability analysis accordingly.

B. In addition to the explanations and clarifications called for in (a), the staff found that some of the information that pertains to the overspeed trip system for the ESBWR turbine is confusing or incomplete and needs to be clarified. Unless otherwise indicated, the following items pertain to the description in Tier 2 Section 10.2:

1) The description of what valves are actuated by the primary and emergency trip systems seems to indicate in some places that only

the turbine stop and intermediate stop valves are actuated and in other places the description indicates that all steam admission valves, including extraction non-return valves, are actuated.

2) With respect to the extraction non-return valves: the types of valves used, where they are located, locations where two valves are needed to address single failure considerations, and provisions to ensure the capability of the extraction non-return valves and associated air system to perform their isolation function (periodic inspection, test, maintenance and corrective actions) are not adequately described.

3) There is no explanation for how valve closure times and seat leakage are confirmed and maintained over time for the turbine steam isolation valves, including the extraction non-return valves.

4) No provisions were found (either in the DCD or in GEH recommendations provided in the Turbine Missile Generation Probability Analysis) that ensure that the local turbine overspeed trip device is periodically tested and maintained.

5) While the description indicates that a "voting" process is used by the primary overspeed trip system to establish a consensus value, there is no explanation as to how the process works to ensure that an erroneously low value from one speed sensor does not adversely impact the consensus value.

6) The bases for the times shown in Figures 10.2-1, 10.2-2, and 10.2-3 are not explained **[the distinction between Figures 10.2-2 and 10.2-3 has not been adequately addressed in the proposed DCD markup];** and Tv is not defined on Figure 10.2-3.

7) The basis for three control valves being able to handle 85 percent steam flow as indicated in Section 10.2.1.2 has not been explained.

8) The response to RAI 10.2-18 indicates that the normal speed control and primary turbine overspeed trip systems share the same turbine speed sensors and speed signals, and that these sensors are separate and redundant to those used by the emergency turbine overspeed trip system. The Tier 2 description needs to be clarified to reflect this information. **[Note that the proposed DCD markup is still confusing in that it only refers to the normal speed control system and does not explain that the primary turbine overspeed trip system uses the speed sensors for the normal speed control system]**

9) Tier 2 Test 14.2.8.2.20 refers to Technical Specification (TS) requirements for the applicable acceptance criteria, but TS requirements do not exist for the turbine steam admission and extraction non-return valves. Therefore, clarification is needed to

properly specify the acceptance criteria that apply.

10) Tier 2 Test 14.2.8.2.27 specifies in the acceptance criteria that turbine speed shall not exceed design limits. This is misleading and incomplete in that this test should also confirm proper performance of the turbine overspeed protection system (both the primary and emergency turbine trip systems). Therefore, to be clear, the last sentence of the Criteria Section should be revised to state: "Plant systems and equipment, including the turbine overspeed protection system and associated components, shall perform in accordance with the appropriate design and testing specifications."

11) Tier 1 Section 2.11.4 needs to be revised to include other structures, systems, and components important to safety consistent with the response to RAI10.2-18, S02.

12) An ITAAC is needed to verify the layout/locations of turbine stop, control, intermediate stop, intercept, and extraction non-return valves.

GEH notes for response to RAI 10.2-18 S03:

The following response also includes answers to specific subjects during the course of discussions with the NRC since the issuance of the RAI 10.2-18 S03 from the NRC. Items not specifically requested in the RAI are included at the end of the GEH responses to RAI 10.2-18 S03. Material beyond that are GEH responses from earlier RAI 10.2-18 supplements and revisions.

In some cases wording has been shortened, or format adjusted, for clarity. GEH reviewers and the ESBWR Project Leadership Team (PLT) made minor recommended wording changes for conformance to other design documents and to provide clearer design details.

NRC Staff question from RAI 10.2-18 S03 and additional requests are in *Italics*.

NRC Staff questions from RAI 10.2.18-S03:

The June 7, 2007, response to RAI 10.2-18, S01, described the diversity that is provided by the primary and emergency overspeed trip systems for the ESBWR turbine. The response indicated that diversity is provided by the design and implementation of the primary and emergency overspeed protection controllers. Because the ESBWR design does not provide the same level of diversity as that called for by SRP Section 10.2 (i.e., one electrical and one mechanical overspeed trip device), it tends to be more subject to common cause and common mode failures than designs that include a mechanical overspeed trip device. Therefore, the following additional information is needed in order for the staff to determine if this deviation from the guidance in SRP Section 10.2 is acceptable:

***A**. In accordance with 10 CFR 52.47(a)(9), Tier 2 Table 1.9-10 needs to be revised to indicate that a mechanical trip device is not used to provide overspeed protection for the ESBWR turbine and appropriate justification for this deviation needs to be included in Tier 2 Section 10.2. The discussion in the DCD should be sufficient for the staff to find that the level of protection provided by the overspeed protection system for the ESBWR turbine is at least equivalent to the level of protection that would be provided by the diverse design called for by SRP Section 10.2. The following items are pertinent to the staff's evaluation in this regard and should be addressed in this RAI response and reflected in the DCD as appropriate:*

GEH response to item A:

DCD Table 1.9-10 will be revised to show an exception to paragraph III.2.c of SRP 10.2. A mechanical overspeed trip device is not provided on the ESBWR turbine, but a suitable alternate system is. Proposed DCD Subsection 10.2.2.4 provides the detailed information to show that the protection provided by the overspeed protection system is at least equivalent to the level of protection provided by the older style mechanical and electronic systems.

DCD Impact:

See Enclosure 2 for proposed DCD mark-ups to Table 1.9-10.

NRC Staff request:

1) *The description of the turbine overspeed protection system (including air and hydraulic systems/interfaces) need to clearly indicate what parts are shared. For example, shared air and hydraulic dump lines and components such as dump valves need to be described in the DCD.*

Additional NRC comments:

Response to Item A.1: Additional information is needed to generally describe what parts of the hydraulic oil system dump lines/headers are shared/common flow paths from the return side of the turbine steam admission valves back to the hydraulic oil reservoir. To the extent that common/shared piping or headers are used, explain why they are not subject to common mode failure due to blockage and also provide a brief summary of this information in the DCD. Likewise, provide a similar discussion for the air discharge path from the non-return valves, including any shared air release/solenoid valves that are used between the primary and emergency trip systems. This part of the response is incomplete and the discussion in the DCD is not clear on this point. This information is important to confirm that independence between the primary and emergency trip systems is maintained throughout and that any shared parts of the system are designed such that common mode/common cause failure considerations have been addressed. Is the oil dumped to the hydraulic reservoir tank through separate primary side and emergency side dump lines? If a single dump line is used, explain why it is not subject to clogging.

The way this is written, it sounds like there is a single air dump line and associated relay dump valve for releasing the air from all of the non-return valves. In order to address common cause/common mode failures, at least two dump paths should be provided and in order to perform periodic on-line testing, each air dump flow path may need to have two dump valves in series. This needs to be better explained, especially the

redundancy that is provided by the design of the air dump flow paths and how the dump valves are tested periodically during plant operation.
GEH has not addressed the question/concern re: use of common/shared flow paths and components for dumping hydraulic oil from the turbine steam admission valves and air from the non-return valves. In reviewing the information that was provided, it appears that common flow paths are used for this purpose. In addition to the use of common flow paths, the air dump flow path appears to use a single air dump valve for up to 12 non-return valves. GEH needs to address the common cause/common mode failure implications associated with using common flow paths and explain why this isn't a problem, and the single active failure associated with using a single air dump valve needs to be addressed. Failure to satisfy single active failure considerations is an exception to SRP Section 10.2 that needs to be acknowledged and justified.

GEH response to item A.1:

The Electro-Hydraulic Control (EHC) system has a central reservoir tank with two pumps and associated filters and control valves. These pumps supply high-pressure oil to open turbine valves and main steam bypass valves. The oil is collected in several return drain headers back the central reservoir for normal operation. Typically one drain header is for the stop valves and one for the control valves. Other drain headers are arranged to collect oil from the intercept, intermediate stop and bypass valves. These are large diameter pipes and are sloped back the electro hydraulic oil reservoir. Quarterly testing ensures that lines are not plugged. The trip manifold has one side with the three (3) primary solenoid trip valves and the other side has the three (3) emergency solenoid valves to dump oil. The EHC system also has control elements for the relay air dump valves that control the functions of the non-return valves. The air comes from the plant instrument air system.

GEH additional response:

Oil is dumped from the SOVs on the trip manifold assembly into the trip manifold assembly drain pan then directly into the EHC reservoir via two drain lines and a backup vent/drain line.

DCD Subsection 10.2.2.2.6 has been revised to show that there will be parallel air relay dump valves for the spring assisted non-return valves. DCD Subsection 10.2.2.2.6 has also been revised to include the closure timing required for the spring assisted non-return valves.

DCD subsection 10.2.2.4 has been revised to include requirements on oil drain lines from the trip manifold assembly back to the electro hydraulic reservoir. Two full capacity drain lines will be used with a vent line.

DCD Impact:

DCD Section 10.2, in Enclosure 2, provides a description of the overspeed protection systems. Revised DCD Subsections 10.2.2.2.6 and 10.2.2.4 to provide more details.

NRC Staff request:

2) *A summary description of the results of a reliability comparison of the two types of overspeed trip systems (or other analysis) that establishes the basis for concluding that the proposed design is at least equivalent to those that include a diverse mechanical overspeed trip device.*

GEH response to item A.2:

The ESBWR turbine overspeed trip design provides acceptable diversity comparable to SRP 10.2. Both the previous and new design generates a turbine trip by dumping EHC oil pressure. The new electronic design is more robust because the older mechanical trip design was "unsupervised" between turbine startups.

The older mechanical trip mechanism could not be verified on-line and could only be tested with a real overspeed test. This required the normal overspeed system to be bypassed. This entails considerably a more dangerous situation and statistically, by an order of magnitude, is less safe than the electronic systems testing capability. Since the new design can be tested on-line and will indicate if signals are out of tolerance or have failed, the proposed electronic design will provide a more robust system verifiability of the trip channels.

The old problematic performance of solenoid valves, steam isolation valves, hydraulic systems and air systems or concerns about shared components and flow restrictions are essentially identical in both designs. It is incumbent upon the owner of the equipment to follow the recommendations of the designer for construction standards and maintenance practices. Although all but the speed sensors can be replaced on-line within a few hours, the time either the primary or emergency overspeed systems can be out of service is moot since they are both diagnosed (failures are not "silent" and have alarms in the main control room) and fail safe; both schemes (which are completely independent) can tolerate and operate with a single failure and both will trip on a second failure. Time to repair is a power generation issue and not a trip reliability issue. It should be noted that, especially for the firmware in the emergency overspeed devices, there is no known mechanism for simultaneously changing the programming or setpoints in three controllers/devices using diverse hardware/software platforms and, despite the low probability of such an event, the programming is monitored for change by the diagnostics. The Mark VIe system was reviewed under DCD Subsections 7.1.4 and 7.1.5 for N-DCIS, 7.7.5 for Steam Bypass and Pressure control.

Please note: The DCD will not use the term "Mark VIe" but use some form of "turbine control system" since Mark VIe is a manufacturer designation.

The turbine overspeed protection scheme is implemented in two independent, triply redundant control schemes. There are two groups of three trip solenoids (six in total) arranged such that the turbine will trip if two out of three solenoids are de-energized in either group. The actual configuration includes four terminal boards in separate RMU cabinets in the turbine building. One pair of terminal boards are connected to three trip solenoids and another pair connected to the other three trip solenoids; each of the 125 VDC trip solenoids are continuously energized by a two out of three vote from the corresponding triply redundant primary or emergency overspeed controllers.
(Note that the trip solenoids may use redundant and uninterruptible made 24 VDC power instead of non-redundant floating 125 VDC power). The positive 125 VDC feed for the trip solenoids is provided by the emergency overspeed protection terminal boards and I/O packs and the negative 125 VDC feed for the trip solenoids is provided by the normal (primary overspeed protection) terminal boards and I/O packs. Interrupting either the positive or negative 125 VDC feed to the solenoids will result in a turbine trip by dumping the high pressure oil from the turbine stop, control, intermediate stop, intercept and air from the non-return extraction valves, therefore the primary and emergency circuits are independent of one another.

In keeping with the triple redundancy of the Mark VIe turbine controller, there are three I/O packs in the turbine building RMU that each independently sense turbine speed and send (via three paths) the speed signals to the Mark VIe controllers to be used for both normal speed control and overspeed protection. Each of the three controllers receives each of the three speed signals and individually votes (performs a median selection); for example three signals of 1795, 1800, 1800 rpm will result in a selected speed of 1800 rpm. The results of the vote are communicated between each of the controllers to alarm if they have come up with different results and additionally any speed signal that is failed or deviates more than a predetermined amount from the selected value is alarmed. Normal operation is possible with a failed speed sensor but a second failed sensor, in the same system, will result in a turbine trip in either the normal or emergency systems.

The three controllers individually determine if the selected speed is greater than the primary overspeed setpoint and, if so, a trip signal is returned to the primary I/O packs; the trip signals are sent via three paths. Each I/O pack will receive a trip signal and individually operate a relay; the relay contacts (i.e. the I/O pack trip decisions) are voted with 2/3 contact logic and will interrupt the negative 125 VDC feed to the trip solenoids (each solenoid has an independent 2/3 vote). The "arm/fire" MCR turbine manual trip is also hardwired "downstream" of the I/O packs at the relay level such that the manual trip is "software free".

There are many diagnostics associated with the controller and I/O packs that include (but are not limited to) monitoring logic power, solenoid power, relays not at the commanded position, I/O pack temperature, I/O pack communication faults, relay coil impedance monitoring that will typically result in a (one of three) trip for that circuit and always result in an MCR alarm.

The primary scheme involves the Mark VIe controllers/logic and I/O packs; the emergency scheme uses only "local" (at the RMU) logic implemented using a different (firmware based) hardware/software platform than that used by the Mark VIe controllers and I/O packs. The three emergency I/O packs each have an individual speed sensor (each different than the primary speed sensors) and will individually determine an overspeed trip (there is no voting of the speed sensors). The emergency overspeed trips as determined by the individual I/O packs are then voted with 2/3 contact logic and will interrupt the positive 125 VDC feed to the trip solenoids (each solenoid has an independent 2/3 vote).

Although the firmware and hardware emergency overspeed trip I/O packs are independent of the Mark VIe controllers and can trip the turbine whatever the status of those controllers, each of the emergency I/O packs is connected to the Mark VIe controllers via three paths. These connections are used to provide diagnostics and to further improve trip reliability. For example the emergency I/O packs monitor communications from the normal controllers (i.e. act as a "watchdog") and will (after a time delay) output a trip on loss of communication. Since there is never a reason for the emergency (locally determined) speed to differ from the Mark VIe (primary) selected speed, a time delayed trip is output if they differ. Gross speed sensor failure detection is included (and alarmed) but more subtle "locked" speed sensor failure is additionally included (advantage is taken of the "dither" associated with all "real world" sensed signals). The emergency I/O pack trip status is also communicated directly to both the Mark VIe controllers and to the primary I/O pack board (an emergency trip causes a primary trip). Finally the usual diagnostics/trips associated with erroneous contact state, solenoid power monitoring, I/O pack temperature, and I/O pack communication faults are included. Also note there are no bypass switches, no key locks, no operations bypass software features. A second failure, or out of range input, on either the primary or emergency system will always trip the turbine.

The increased and continuous diagnostic capability, triple redundancy and different speed sensors of the primary and emergency overspeed trip schemes and especially the lack of need to actually overspeed the turbine for the mechanical overspeed trip test all contribute to a more reliable and robust overspeed trip scheme than possible or available from the old mechanical/electrical overspeed trip design. With the segregated diverse emergency system the redundancy is assured. The reliability has been calculated by the equipment manufacturer to be an order of magnitude safer than the electronic and mechanical systems used in past installations. The common cause and failure modes and effects analysis can be audited at the NRC request.

Also see GEH response to part B.5 of this RAI.

DCD Impact:

DCD Section 10.2 has been revised to include a summary high level discussion on the overspeed trip system. Proposed DCD Section 10.2 is included in Enclosure 2.

NRC Staff request:

3) *Factors and assumptions that are important for the analysis referred to in (2) to be valid should be described and COL action items should be established as appropriate to ensure that these considerations are properly implemented and maintained. For example, the amount of time that either the primary or emergency overspeed trip system can be out of service for maintenance is an important factor. Assumptions that periodic inspections, maintenance, testing, and corrective actions will be properly implemented in accordance with GEH and other vendor recommendations in order to ensure reliable performance is another important factor.*

GEH response to item A.3:

A proposed revision to COL 10.2-1-A requires the COL applicant to provide the basis for continually ensuring that the Missile Probability Analysis report is not compromised. This includes the time out of service and recommended turbine and valve testing and inspection requirements.

DCD Impact:

Enclosure 2 has the proposed revision to COL Information 10.2-1-A.

NRC Staff request:

4) *Common mode and common cause failure considerations that could prevent the overspeed trip systems from functioning properly and are pertinent to the design should be addressed. For example, the performance of solenoid valves, steam isolation valves, hydraulic systems and air systems have historically been problematic in this regard. Also, the potential for flow restrictions to occur in hydraulic or air system dump lines is of concern (especially in those cases where redundant flow paths are not provided) and need to be addressed. Design and programmatic measures that provide assurance that these common mode and common cause failures are not likely to occur should be described and means to ensure proper implementation by COL applicants should be established as appropriate.* ***[Note that the proposed DCD markup on the top of Page 10.2-8 needs to include provisions for the extraction non-return valves, and the "augmented inspection program" referred to on Page 10.2-10 needs to be explained (e.g., where is this augmented inspection program specified, the turbine missile probability analysis does not include specific inspection and test requirements for the extraction non-return valves.)]***

GEH response to item A.4:

Under response A2 of this RAI the basis for common mode and common cause failures have been outlined. Enclosure 2 has the proposed DCD mark-up for DCD Section 10.2. Please also see the GEH response to RAI item A.1 for more information.

For the common cause review GE-STG uses the original NUREG 1048 Supplement No. 6 (Docket No. 50-354, July 1986), the NUREG 1275 and the EPRI Risk Evaluation of Nuclear Steam Turbine Destructive Overspeed Final Report #1008740 (July 2003) plus the most up to date in-house information from the installed base machines in Fossil and Nuclear to determine the outcome of mechanical Failure Modes and Effects Analysis (FMEA). The Mark VIe has a separate review for the digital control systems. The common cause and failure modes and effects analysis can be audited at the NRC request. The Mark VIe system was reviewed under DCD Subsections 7.1.4 and 7.1.5 for N-DCIS, 7.7.5 for Steam Bypass and Pressure control.

DCD Impact:

The description of the augmented inspection program has been revised in proposed DCD Section 6.6.7 and COL 6.6-1-A and several parts of DCD Section 10.2.

NRC Staff request:

- *The use of certain materials that are not subject to corrosion, conditioning equipment, desiccants, filters and design standards are examples of design considerations that may be pertinent for addressing common mode and common cause failures.*

GEH response to item A.4 bullet one (1):

DCD Subsections 9.3.6 and 9.3.7 discuss the Instrument and Service Air systems. The Instrument air system meets the requirements of GDC 1 as it pertains to minimum instrument air quality standards by meeting Instrument Society of America standard 7.0.01. The instrument air system makes use of the Service Air System compressors to provide filtered, dry and oil-free compressed air for plant instrumentation, control systems and pneumatic valve actuators. The service air system compressors provide compressed air to the instrument air system via two (2) air receivers. Air, leaving the service air system air receivers, passes through one of two parallel instrument air filtering and drying trains and an instrument air system receiver tank before being distributed to the instrument air system piping. Each instrument air system train is equipped with an air receiver, redundant prefilters, a regenerative desiccant dryer, and redundant after filter. Both instrument air trains are connected to a common header, which distributes to the Turbine Building and other buildings. DCD Table 1.7-1 has stainless steel material called out for standard line designations “AM” for instrument air system and “AS” for service air system therefore the supply of clean control air to turbine extraction non-return valves (NRVs), instruments and solenoid valves will preclude common mode failures from air contamination. Air filters are periodically inspected for cleanliness, and the desiccant in the air dryers is periodically sampled to verify its useful life. Periodic testing of air quality is performed to ensure compliance with Instrument Society of America Standard 7.0.01.

The Electro Hydraulic Control (EHC) system is designed to preclude failures and be highly reliable. It has incorporated the most up-to-date technologies for processing hydraulic oils. For example operational experience has dictated the use of titanium tubing for the oil coolers to preclude water contamination in the EHC fluid.

GE-STG uses several industry documents to evaluate the statistical chances of equipment failures and industry experience plus a long history of design practices to provide asset protection to the clients. NRC RAI question A.4 has a partial list of the documents used. These documents and evaluations can be audited by the NRC at the G.E. Turbine Generator manufacturing facility.

DCD Impact:

DCD 10.2.2.4 has been revised to include the design features discussed in the response above, see Enclosure 2. DCD Chapter 9 did not require any changes.

NRC Staff request:

- *Implementation of periodic inspections, maintenance, testing, and corrective actions are examples of programmatic controls that may be applicable for assuring that common mode and common cause failures are prevented from occurring. For example, measures that assure the reliable performance of components and the quality of hydraulic and air systems are pertinent in this regard.*

GEH response to item A.4 bullet two (2):

As indicated in this response under RAI A.4 bullet one (1) the instrument air system is tested to Instrument Society of America Standard 7.0.01. The EHC oil system is tested per General Electric requirements found in GEK 46357e (or equal) and testing instructions can be found in GEK 111354b (or equal) for the D1600N Trip Manifold Assembly. Both of these have been sent to the NRC for information. General Electric has an extensive library of manuals and documents that specify the installation, testing, maintenance, and operation of all equipment associated with the importance of the asset protection of the turbine generator set. General Electric also keeps the clients updated with technical and service letters documenting the latest information and operational experiences. Augmented inspection of valves and the turbine is covered under COL Information item 6.6-1-A.

DCD Impact:

Enclosure 2 has the proposed COL Information item 6.6-1-A and 10.2-1-A.

NRC Staff request:

5) *Failure of extraction non-return valves to function will tend to increase the probability of turbine overspeed and this is an important consideration in the turbine missile probability analysis that must be completed by COL applicants. Therefore, provisions need to be established and included in the DCD to ensure that COL applicants will properly model the failure of extraction non-return valves in the turbine missile probability analysis accordingly.*

<u>*Additional NRC comments:*</u>
With respect to COL Items 10.2-1-A (and 10.2-2-A, [NRC] take exception to the view that it is not necessary to credit the non-return valves in the turbine missile probability calculation and turbine missile probability analysis. The later can be addressed with the COL applicant provided this position is not being established in the DCD and supporting documents. So, GEH needs to confirm that this is not the case and that the COL applicant will not be able to claim finality on this point.

<u>GEH response to item A.5:</u>

The COL Information item 10.2-1-A has been revised to include the augmented inspection program covered under COL Information item 6.6-1-A. It also includes specific requirements pertaining to what is to be included and requires the basis for the recommendations back to the Turbine Missile Probability Analysis report. Credit taken for spring assisted non-return valves is listed in the missile probability report and calculations are to be completed in the detailed design phase of the ESBWR design. COL Information item 10.2-2-A will cover the analysis.

<u>DCD Impact</u>:

Enclosure 2 has the proposed DCD Section 10.2 with COL Information item 10.2-1-A included.

<u>NRC Staff request:</u>

B*. In addition to the explanations and clarifications called for in (a), the staff found that some of the information that pertains to the overspeed trip system for the ESBWR turbine is confusing or incomplete and needs to be clarified. Unless otherwise indicated, the following items pertain to the description in Tier 2 Section 10.2:*

1) *The description of what valves are actuated by the primary and emergency trip systems seems to indicate in some places that only the turbine stop and intermediate stop valves are actuated and in other places the description indicates that all steam admission valves, including extraction non-return valves, are actuated.*

<u>GEH response to item B.1:</u>

Either the primary or emergency overspeed trip system can initiate a turbine trip signal and provide the closure function to all valves important to turbine safety. These valves are the stop, control, non-return, intermediate stop, and intercept valves. The trip manifold assembly dumps the control oil from hydraulic valves and the relay air dump valves remove the motive force holding open the non-return extraction valves. All valve important to turbine safety are spring to close and are tested each quarter as per the requirements of the Turbine Missile Probability Analysis report.

DCD Impact:

Enclosure 2 has the proposed DCD Chapter 10.2 and Subsection 10.2.2.4, which has been revised to clarify the functions of the normal speed control system and the emergency trip system.

NRC Staff request:

2) *With respect to the extraction non-return valves: the types of valves used, where they are located, locations where two valves are needed to address single failure considerations, and provisions to ensure the capability of the extraction non-return valves and associated air system to perform their isolation function (periodic inspection, test, maintenance and corrective actions) are not adequately described.*

Additional NRC comments:

GEH has provided inconsistent information concerning where non-return valves are located and to what extent they are needed in order to prevent the turbine from exceeding 120% rated speed, including consideration of single failures. [NRC] current understanding based on the most recent information that was provided is that both power assisted and simple non-return check valves need to be credited to prevent the turbine from exceeding 120% rated speed during a loss of load event. The proposed revision in the February 28 e-mail response provides an acceptable description. However, the Tier 1 functional diagram needs to be revised to include simple non-return check valves that are needed to prevent the turbine from exceeding 120% rated speed.

GEH response to item B.2:

DCD Figure 10.4-6a has been revised to correct the quantity of non-return valves required for the number four (4) open feedwater heater. This is also discussed in DCD Subsection 10.2.2.2.6.

The proposed DCD Subsection 10.2.2.2.6 and Figure 10.4-6a shows the location and quantity of spring assisted extraction steam non-return valves that are required on the low pressure heaters by the preliminary entrained energy analysis performed by General Electric steam turbine division.

DCD Figure 10.4-7a also shows locations where spring assisted extraction steam non-return valves are required on the high-pressure heaters. DCD Figure 10.4-7a was revised to correct the orientation of the spring assisted non-return valves on the 5A and 6A feedwater heaters, they were shown backwards in earlier revisions of the DCD.

DCD Subsection 10.2.2.7, 10.2.3.7 and COL Information item 10.2-1-A have also been revised to include the high level requirements for periodic inspection, testing, maintenance and corrective actions of valves important to turbine protection.

Only the spring assisted non-return valves are credited for any reduction of turbine speed during a loss of generator load event or turbine trip. Simple check type valves installed in extraction lines are only for prevention of moisture carryover and vibrations at low load operation.

The Tier 1 drawings referred to in the additional NRC comment is discussed under part B.12 of this RAI.

DCD Impact:

Enclosure 2 contains the proposed revised drawings 10.4-6a, 10.4-7a, Subsection 10.2.2.4, 10.2.2.7, 10.2.3.7 and DCD COL Information item 10.2-1-A.

NRC Staff request:

3) *There is no explanation for how valve closure times and seat leakage are confirmed and maintained over time for the turbine steam isolation valves, including the extraction non-return valves.*

GEH response to item B.3:

A proposed DCD COL Information item 10.2-1-A, has been revised to contain the requirements for the augmented valve inspection and testing program to include confirmation of valve closure times and seat leakage tests. These values will be calculated during detailed design and could not be included in the DCD at this time.

DCD Impact:

Enclosure 2 contains the proposed DCD COL Information item 10.2-1-A and COL Information item 6.6-1-A

NRC Staff request:

4) *No provisions were found (either in the DCD or in GEH recommendations provided in the Turbine Missile Generation Probability Analysis) that ensure that the local turbine overspeed trip device is periodically tested and maintained.*

GEH response to item B.4:

A proposed DCD Subsection 10.2.2.4 has information on the two manual turbine trip switches. The manual switches are tested during refuel outages prior to turbine start-ups or if maintenance work on the wiring could have introduced a potential for loss of continuity or functionality.

DCD Impact:

Enclosure 2 contains the proposed DCD Subsection 10.2.2.4 and 10.2.2.5

NRC Staff request:

5) *While the description indicates that a "voting" process is used by the primary overspeed trip system to establish a consensus value, there is no explanation as to how the process works to ensure that an erroneously low value from one speed sensor does not adversely impact the consensus value.*

GEH response to item B.5:

The GE Mark VIe for the turbine control system has a Voting System and Fault Detection, Output Processing, Input Processing systems. In the Mark VIe instruction manual it shows the non-fanned configuration for highly reliable speed input applications, voting section (median value), and turbine protection section. The Mark VIe manual has been supplied to the NRC for information.

So the question is really - is the simultaneous common cause failure of the six speed sensors, which are verified operational continuously, greater or less than the risk of real overspeed imposed by mechanical trip system testing? And the failure is all six reporting a lower, but still consistent, speed than the real turbine speed instead of a complete failure to report speed, which would itself cause a trip - this is not a failure mode of pulse counting hall sensors.

Also note that the turbine control valves in a BWR have always been used to control reactor pressure in normal operation and not (except for initial turbine startup) to control turbine load or speed. Normally BWR turbine load is controlled by changing reactor power/steam flow and letting the pressure regulator position the control valves and turbine speed is controlled because the synchronous generator is connected to the grid. The speed controller is biased 10% out of the way of the SB&PC (controlling pressure) signal. Locked to the grid, the speed sensors don't do much in normal operation and the turbine stays at 1800 RPM, but if they were indicating lower than the actual speed, and were not biased out of the way, the control system response would be to open the TCV to increase speed. That would cause reactor/turbine inlet pressure to drop, since thermal power/steaming rate does not increase. Eventually the MSIVs would close on low steam line pressure. The closed MSIVs would tend to limit turbine overspeeding. This argument forces the common mode failure of the sensors to have to occur simultaneously with the overspeed event requiring their use.

The only way to test a mechanical overspeed "sensor" is to mechanically overspeed the turbine after disabling the electronic trip. Keeping in mind that energy is speed squared there is a small, but finite chance that the required periodic test will fail the turbine. On the other side the all electronic primary and emergency overspeed trips do not require an actual overspeed such that the turbine need never go >1800 RPM for other than transients whose frequency is about the same as the test requirement (i.e. doubling the opportunity). This allows an approximate order of magnitude decrease in the probability of overspeed with the all-electronic system.

In addition to the Mark VIe monitoring the speed sensors for operability and inconsistency (and appropriately alarming) Tech Spec monitoring workstations (A or B) will independently monitor speed reported by the Mark VIe and grid/generator frequency and alarm on a discrepancy. This is important because the Tech Spec monitoring workstation has a different hardware/software platform than the Mark VIe and will also alarm on loss of communication from the Mark VIe. The sensors cannot fail silently in normal operation.

The remote chance of all the speed sensors simultaneously failing during an overspeed event and not shutting the stop and control valves would result in an MSIV HI steam flow/LOW inlet pressure trip. The SB&PC system will open 100% bypass valves and if the TSV/TCV are still flowing 100% turbine steam flow, the MSIVs will be tripped. Specifically the load reject/turbine trip design "expects" the turbine steam flow to be about zero in 100 - 200 msec.

The Mark VIe system was reviewed under DCD Subsections 7.1.4 and 7.1.5 for N-DCIS, 7.7.5 for Steam Bypass and Pressure control.

DCD Impact:

Enclosure 2 has the proposed DCD Subsection 10.2.2.4 with details of the voting scheme.

NRC Staff request:

6) *The bases for the times shown in Figures 10.2-1, 10.2-2, and 10.2-3 are not explained* ***[the distinction between Figures 10.2-2 and 10.2-3 has not been adequately addressed in the proposed DCD markup];*** *and T_v is not defined on Figure 10.2-3.*

GEH response to item B.6:

The three graphs, DCD figures 10.2-1, 10.2-2, 10.2-3, were derived from many start-up tests for the older generation BWR reactors and turbine generator systems. Their applicability for ESBWR was confirmed by the transient analyses in DCD Chapter 15. These graphs are the basis of the control scheme to limit the fast neutron flux in the reactor due to turbine trips and power load imbalances in the grid for a BWR. Neutron flux increases, because of the void reduction caused by the pressure increase. By controlling the closure speed of the valves and the opening speed of the bypass valves the reactor can still operate without a SCRAM in most cases.

The three graphs in the DCD are the only three that are required to portray the information for the worse case of turbine tripping or single valve inadvertently closing so as not to cause a large pressure spike in the reactor thus a collapse of the voids and in turn a high flux SCRAM. Note these are non-safety valves and control functions. The valve timing has been shown to be good operational design practice. The evaluations of valve failures are incorporated in the DCD under Subsection 15.2.2. The general discussion on the valve closure times can be found in DCD Subsection 15.2.2.1. Since this is covered under DCD CH 15, a CH 10 inclusion of the same information is not required.

During normal power range operation, the main steam turbine control valves, positioned in response to the pressure regulation demand signal, control steam pressure. The steam bypass valves are normally closed. When the reactor is in the automatic load following mode, fast load demand changes require an early response in steam flow preceding the actual change in steam production. Because the fast response in turbine steam flow (equivalent load) acts to reduce the load-demand error, as well as tending to reduce neutron flux, an additional pressure setpoint adjustor forcing-function is provided.

Events that induce reactor protection trip logic (SCRAM) result in significant transients during which the pressure control system must maintain steam pressure. These transients are characterized by large variations in vessel steam flow, core thermal-power output, all of which affect vessel water level. Hence, the pressure control system must respond quickly to stabilize system pressure and thus aid the feedwater/level control in maintaining water level. The pressure control system must also be capable of controlling pressure during normal (main steam isolation valves open) reactor shutdown to control the reactor cooling rate.

The pressure control system provides responsive, stable performance to minimize vessel water level and neutron flux transients caused by normal operational plant maneuvers (pressure setpoint changes, level setpoint changes). The pressure control system operation is also integrated with other reactor control systems to avoid reactor SCRAM after significant plant disturbances, such as: partial and full generator load rejection, trip of one feedwater pump, inadvertent opening and closing of safety/relief valves or steam bypass valves, and main turbine stop/control valve surveillance testing, and steam line isolation valve testing.

Since the design of the turbine-generator controls must be compatible with the Steam Bypass and Pressure Control (SBPC) design, as both control systems use the turbine control valves, the pressure control functions are described herein together with the turbine control features necessary for proper reactor operation. ESBWR pressure control is accomplished by controlling main steam pressure within the reactor vessel dome region, through modulation of the turbine control or steam bypass valves. Command signals to these valves are generated by a triplicated fault-tolerant digital controller using the sensed reactor vessel pressure signals as the feedback. For normal power range operation, the turbine control valves regulate steam pressure; however, when ever the total steam flow demand from the pressure controller exceeds the effective turbine steam flow, the pressure control system sends the excess steam flow directly to the main condenser, through the steam bypass valves. Ability of the plant to follow grid-system load demands is enabled by adjusting reactor power level, by varying feed water temperature (manually or automatically), or by moving control rods (manually or automatically). In response to the resulting steam production changes, the pressure control system adjusts the turbine control valves to accept the steam output change, thereby controlling steam pressure. In addition, when the reactor is automatically following grid-system load demands, the pressure control system permits an immediate steam flow response to fast changes in load demand, thus using part of the stored energy in the vessel.

Upon a turbine trip (except turbine trip initiated by high condenser pressure) from power levels up to rated power, the pressure control system, in conjunction with the turbine control system, should be capable of avoiding a reactor scram depending on some factors. Sufficient steam bypass capacity and acceptable response characteristics are required to avoid reactor SCRAM on high neutron flux or reactor isolation on high steam line flow. To minimize the steam flow to the main condenser, SRI (Select Rod Insert) and SCRRI (Selected Control Rod Run-In) will be utilized to reduce reactor power, as required.

DCD Figure 10.2-3 has been corrected by adding the missing subscript "v" from T_v.

DCD Impact:

Enclosure 2 includes the revised DCD Figure 10.2-3. DCD Subsection 10.2.1.3 has been revised to indicate that DCD chapter 15 has the required information for the valve response figures.

NRC Staff request:

7) *The basis for three control valves being able to handle 85 percent steam flow as indicated in Section 10.2.1.2 has not been explained.*

GEH response to item B.7:

DCD Subsection 15.2.2.1.2, under the System Operation subsection discusses the 85% value. ESBWR is designed as a full-arc high-pressure turbine section. The Chapter 15 analysis is done under the worse case of partial-arc style steam admission to cover any potential modifications potentially done in the future.

DCD Impact:

Enclosure 2 has the proposed DCD mark up for Subsection 10.2.1.2. A reference has been added to the bulleted item that includes the 85% Non-Safety Power Generation Design Bases.

NRC Staff request:

8) *The response to RAI 10.2-18 indicates that the normal speed control and primary turbine overspeed trip systems share the same turbine speed sensors and speed signals, and that these sensors are separate and redundant to those used by the emergency turbine overspeed trip system. The Tier 2 description needs to be clarified to reflect this information.* ***[Note that the proposed DCD markup is still confusing in that it only refers to the normal speed control system and does not explain that the primary turbine overspeed trip system uses the speed sensors for the normal speed control system]***

GEH response to item B.8:

The speed control system is part of the turbine overspeed protection and is available in three levels; control, primary, and emergency. Control protection comes through closed loop speed control using the steam valves. The software-voting controller provides primary overspeed protection. The shaft speed signal is sent to each controller where the median signal is selected. If the controller determines a trip condition, it sends the trip signal to the I/O board. The three outputs are 2/3 voted in three-relay voting circuit (one for each trip solenoid coil) and power is removed from the solenoids for a turbine trip.

Emergency overspeed protection is provided by the independent triple redundant protection system. This uses three separate shaft speed signals from magnetic pickups, one for each protection module that are independent from the normal speed control system. Highly reliable speed input applications are brought in as dedicated inputs. These signals are brought into a terminal board dedicated to the protection system. Each processor independently determines when to trip, and the signals are passed to the terminal board with the voting hardware. The voting hardware use relays to perform a per trip solenoid two out of three vote on the trip decisions. This system contains no software voting, making the three modules completely independent. The only link between processor and the other parts of the control system is the IONet cable, which transmits status information.

A full discussion and diagrams can be found in General Electric Mark VIe Control System Guide, Volume 1 (GEH-6721D or equal) that has been transmitted to the NRC for information.

DCD Impact:

Enclosure 2 has the proposed DCD mark up for Subsection 10.2.

NRC Staff request:

9) *Tier 2 Test 14.2.8.2.20 refers to Technical Specification (TS) requirements for the applicable acceptance criteria, but TS requirements do not exist for the turbine steam admission and extraction non-return valves. Therefore, clarification is needed to properly specify the acceptance criteria that apply.*

GEH response to item B.9:

DCD Subsection 14.2.8.2.20 will have the correct reference to all of the valves being tested by Technical Specifications or augmented programs. Only the steam bypass valves are specifically included in the ESBWR Technical Specifications.

DCD Impact:

Enclosure 2 includes the proposed revised DCD Subsection 14.2.8.2.20.

NRC Staff request:

10) *Tier 2 Test 14.2.8.2.27 specifies in the acceptance criteria that turbine speed shall not exceed design limits. This is misleading and incomplete in that this test should also confirm proper performance of the turbine overspeed protection system (both the primary and emergency turbine trip systems). Therefore, to be clear, the last sentence of the Criteria Section should be revised to state: "Plant systems and equipment, including the turbine overspeed protection system and associated components, shall perform in accordance with the appropriate design and testing specifications."*

GEH response to item B.10:

The turbine overspeed protection system includes turbine control, primary turbine trip and emergency turbine trip elements. DCD Subsection 14.2.8.1.59 (Bullet 9) is the testing used for proper operation of the turbine overspeed protection system. Since the system is all electronic it can be tested with simulated signals while the turbine is at rest. Actual turbine overspeed tests are not required to verify overspeed systems operability. The 6 Hall effect sensors are pre-tested and are functionally tested during turbine roll-up to speed. A tolerance band on the signal from each speed sensors is continually monitored and voted for proper operation. DCD Subsection 14.2.8.2.27 was written for a specific test of generator load rejection. With proper operation of the turbine control portion of the turbine overspeed protection system, the load rejection test is not expected to result in or exercise the overspeed trip systems.

DCD Impact:

Enclosure 2 has the proposed DCD mark up for Subsection 14.2.8.2.27 to clarify the testing requirements.

NRC Staff request:

11) *Tier 1 Section 2.11.4 needs to be revised to include other structures, systems, and components important to safety consistent with the response to RAI 10.2-18, S02.*

Additional NRC comments:

During teleconference on 3/22/2010 and E-Mails on 3/22/2010 the NRC suggested Tier 1 wording modifications.

GEH response to item B.11:

A proposed DCD mark up for Tier 1 Section 2.11.4 includes other structures, systems, and components important to safety consistent with the response to RAI 10.2-18 S02.

Wording will be revised to accept the NRC suggestions from the 3/22/2010 phone and E-Mail interactions.

DCD Impact:

Enclosure 2 has the proposed DCD mark up for Tier 1 Section 2.11.4

NRC Staff request:

12) *An ITAAC is needed to verify the layout/locations of turbine stop, control, intermediate stop, intercept, and extraction non-return valves.*

Additional NRC comments:

GEH has clarified that the steam line from the HP turbine exhaust to the No. 5 feedwater heaters is an "extraction steam line" that taps into the turbine exhaust line. This is different from what GEH originally indicated in their February 28 e-mail response and their use of the term "extraction steam" in this manner is rather unusual. However, if this is the way they want to characterize it, the description in the DCD should be consistent throughout, including how this flow path is represented on applicable figures. For example, this "extraction steam" flow path is not shown on proposed Tier 1 Figure 2.1.11-3, "Extraction Steam Functional Arrangement," but is shown on proposed Tier 1 Figure 2.11.1-2, "High Pressure Turbine Exhaust Functional Arrangement," and this needs to be corrected.

During teleconference on 3/22/2010 and E-Mails on 3/22/2010 the NRC agreed that an additional ITAAC would cover the inspection of spring assisted extraction non-return valves.

GEH response to item B.12:

DCD Tier 1 Subsection 2.11.1 covers the proposed DCD Tier 1 design description, Table 2.11.1-1 and Figure 2.11.1-1, -2, and –3 diagrams that verify the layout/locations of turbine stop, control, intermediate stop, intercept, and spring assisted extraction non-return valves. The DCD Figure 2.11.1-2 has the exhaust steam and extraction steam lines labeled to preclude confusion on location. Simple check type non-return valves installed on extraction lines are not required to be shown in the DCD or Tier 1 since they do not have a function in turbine overspeed protection.

DCD Impact:

Enclosure 2 has the proposed DCD Tier 1 descriptions, Table and Figures 2.11.1-1, -2, and –3 to verify the layout/locations of turbine stop, control, intermediate stop, intercept, and spring assisted extraction non-return valves.

The following items are a compilation of GEH and NRC correspondence during the question and answer period from the draft submittal of RAI 10.2-18 S03 to issuing this MFN letter.

Staff's comment I:

The following items pertain to the information in the DCD, as indicated in the attachments to the response:

Section 10.2.1.1: Because this is a passive plant, this discussion should also recognize the importance of RTNSS Category B equipment and/or equipment that is necessary for achieving and maintaining safe shutdown conditions.

GEH Response:

The TG does not perform or support any safety related function, and thus, has no safety design basis. The TG is, however, a potential source of high energy missiles that could damage safety related or RTNSS Category B SSCs. The turbine is designed to minimize the possibility of failure of a turbine blade or rotor. Turbine integrity is discussed in Subsection 10.2.3. The effects of potential high energy missiles are discussed in Section 3.5 and Subsection 10.2.4.

DCD Impact:

RTNSS Category B has been added to DCD subsection 10.2.1.1.

Staff's comment II:

Section 10.2.1.3: First sentence, need to include non-return valves.

GEH Response:

Turbine main steam stop, control valves, intermediate stop valves, intercept valves and non-return valves protect the turbine from excessive speeds.

DCD Impact:

"Non-return valves" have been added to DCD subsection 10.2.1.3.

Staff's comment III:

Section 10.2.1.3.2: First sentence, include the reason for the times shown in Figure 10.2-2 (e.g., to comply with transient requirements).

GEH Response:

During any event resulting in turbine control valve fast closure, the turbine inlet steam flow is not reduced faster than that shown in Figure 10.2-2 to comply with the transient requirements.

DCD Impact:

DCD Subsection 10.2.1.3.1 and 10.2.1.3.2 has been revised to show that the valves are to comply with transient requirements.

Staff's comment IV:

Section 10.2.2.1: The last paragraph should recognize RTNSS B and RG 1.117 equipment, similar to what was added to Page 10.2-19.

GEH Response and DCD impact:

"or RTNSS Category B functions, as listed in DCD Table 19A-2 and 19A-3, or structures, systems and components listed in Regulatory Guide 1.117 Appendix" has been added to the last paragraph of DCD Subsection 10.2.2.1.

Staff's comment V:

Section 10.2.2.6: This should be retitled to HP Turbine Exhaust and Extraction Non-return Valves, and hp turbine added to the discussion.

GEH Response:

Section 10.2.2.2.6 (in place of 10.2.2.6 - Turbine Generator Supervisory Instruments) has been expanded to include more information on non-return valves. The high pressure turbine is discussed in DCD subsection 10.2.2.2.2 and has had some proposed revisions in the description.

Additional NRC comment for V:

Correct, the comment is directed to 10.2.2.2.6. The focus of this particular section is on non-return valves and the comment that needs to be addressed is that the hp turbine exhaust as well as hp and lp extraction steam lines contain non-return valves. Therefore, the section should be retitled to HP Turbine Exhaust and Extraction Steam Non-return Valves, and the section should include discussion/recognition of the HP turbine exhaust non-return valves as well as the hp and lp turbine extraction steam non-return valves.

Additional GEH response:

There are no non-return valves in the HP exhaust to the moisture separator reheaters (MSR). There are extraction lines that tap off of the HP turbine exhaust to feed the number 5 feed water heaters and they do have spring assisted non-return valves. GEH considers DCD section 10.2.2.2.6 is correct as written with the added details requested. Tier 1 has been revised to show the diagrammatic routing of the steam lines and locations of spring assisted extraction non-return valves.

Upon loss of load, the steam contained downstream of the turbine extractions can flow back into the turbine, across the remaining turbine stages, and into the condenser. Associated condensate can flash to steam under this condition and contribute to the backflow of steam or water can be entrained with the steam flow and damage the turbines. Non-return valves are employed in selected extraction lines to minimize potential for overspeeding and also for preventing water entrainment (Subsection

10.2.2.2.6). Two types of non-return valves are provided, spring assisted closure type and simple check valve type. Spring assisted non-return valves are held open with instrument air and receive a closure signal opening the relay air dump valves. When the extraction can potentially result in an overspeed close to the maximum allowable limit for repeated occurrence (emergency overspeed), the extraction includes one spring assisted non-return valve. The extractions that have the potential to drive the unit above the emergency overspeed are equipped with two (2) spring assisted non-return valves, activated by the primary or emergency trip system. The spring assisted non-return valves are located on high pressure extraction steam lines to the number five (5) and six (6) feedwater heaters. They are also mounted on extraction lines feeding the open feedwater heater (number four (4)), but two are mounted in series for single failure proof protection since this heater contains a very large volume of water and potential energy. The number three (3) feedwater set, of low pressure heaters, also are required to have the spring-assisted type.

Simple non-return valves are used for the two strings of low-pressure heaters (heater numbers one (1) and two (2)) because of the relative low potential energy for increasing the turbine speed. The simple non-return valves on the last two stages of feed water heating are also for prevention of moisture carryover and flashback vibrations at low load operation and not required for turbine overspeed protection. The type and location of non-return valves can be adjusted during detailed design when the entrained energy calculations are completed.

The air is supplied by the plant instrument air system.

<u>DCD Impact:</u>

DCD Subsection 10.2.2.2.6 has been revised.

<u>Staff's comment VI:</u>

Section 10.2.2.4: Proposed change near the bottom of Page 10.2-6, the following sentence should be deleted as it is rather confusing: "All valves important to turbine protection are capable of closure concurrent with the steam stop valves." [The steam stop valve is just another valve important to turbine protection, so why the distinction?]

<u>GEH Response and DCD Impact:</u>

"with the stop valves" has been deleted from DCD 10.2.2.4. Agree that might have been confusing. The valves all can close concurrently. The original sentence was derived from NRC SRP 10.2, part II.2, second sentence.

Staff's comment VII:

Section 10.2.2.4: The proposed change in the last paragraph on Page 10.2-7 to replace "unique" with "separate" doesn't really convey diversity in the design. If unique is not the right word, my suggestion is to change the sentence to "...by providing a different hardware and logic design..." if this is accurate because it still describes diversity in the design. (deleted =>separate)

GEH Response and DCD Impact:

DCD Subsection 10.2.2.4 has been revised to: Diversity is provided by separate sets of physically isolated primary and emergency overspeed protection controllers. The primary overspeed trip and emergency overspeed trip controllers are independent and diverse by providing unique hardware and logic design and implementation. This separate hardware and logic design between the primary and emergency overspeed trip control systems provide redundancy and diversity.

Staff's comment VIII:

Section 10.2.2.4: The proposed change on Page 10.2-8, last sentence in the first paragraph where it states "...turbine overspeed implementation..." requires clarification. suggested wording - I think this is more clear

GEH Response and DCD Impact:

Deleted the word "speed" from DCD subsection 10.2.2.4 and revised wording.

Staff's comment IX:

Section 10.2.2.4: The proposed change on Page 10.2-9, last sentence says that simple non-return valves are used for the two strings of low-pressure heaters because of the relative low potential energy for increasing the turbine speed. My understanding was that these simple non-return valves are used for preventing moisture carryover back to the turbine and that they are not needed to prevent turbine overspeed. Does the description need to be changed or is my understanding incorrect?

GEH Response:

Based upon recent experience, GE-STG has implemented additional criteria for the use of non-return valves for large new units to prevent return flow of steam and water from the condenser neck mounted feedwater heaters to the steam path during a load rejection event. Preventing return flow, commonly known as flashback, eliminates the potential for unsteady supersonic/transonic flow entering the steam path that could under some circumstances result in reduced rotor and bucket life. Results of studies indicate that in full speed no load (FSNL) operation, the steam in the extractions can return from condenser neck mounted feedwater re-heater and result in a direct stimulus to the turbine bucket. Therefore simple check type non-return valves are installed to preclude certain vibrations and moisture carryover. These simple check type valves in the low-pressure heater extraction lines are not needed for turbine overspeed protection.

DCD Impact:

DCD subsection 10.2.2.2.6 has been revised. Duplication of this same information was removed from the draft DCD10.2.2.4 that was sent to the NRC.

Staff's comment X:

Section 10.2.2.4: Middle of Page 10.2-9 should include hp turbine exhaust and extraction non-return valves in the list of component redundancies and associated discussion.

[NRC] understanding is that the hp turbine exaust non-return valves are needed to prevent turbine overspeed (especially since they are the power operated type as opposed to the simple type design). If my understanding is incorrect and these non-return valves are not needed to prevent turbine overspeed, this distintion needs to be made in the discussions in Sections 10.2.2.2.2 and/or 10.2.2.2.6 to ensure that there is no confusion on this point in the future.

GEH Response and DCD Impact:

DCD 10.2.2.4 has been updated to clarify the use of non-return valves.

GEH finds the change from "A series set" to "Two" acceptable. Proposed DCD wording: Two non-return valves are installed in each of the number four (4) feedwater heater extraction lines for single failure proof protection.

The eight HP exhaust lines are designed to feed the 4 moisture separator reheaters (two lines per MSR). Some HP exhaust feeds the number five (5) feedwater heater. The

#5s are protected by a power operated non-return valve back to the turbine. GEH believes this to be minor design detailed.

A sentence has been added to DCD Subsection 10.2.2.2.2 to clarify the location of the fifth point feedwater extraction steam.

Staff's comment XI:

Section 10.2.5: COL Item 10.2-1-A indicates that the COL applicant will provide a description of the plant specific turbine maintenance and inspection program required to satisfy the Original Equipment Manufacturer's turbine missile generation probability calculation. Section 5.1.3 of the GE-ST "ESBWR Steam Turbine - Low Pressure Rotor Missile Generation Probability Analysis" [MPA] ST-56834/P, Revision 1, indicates that the non-return valves are not modeled in the analysis. This is non-conservative in that non-return valve failures are not factored into the turbine overspeed probability determination which is a factor in determining the probability of generating a turbine missile. In fact, Section 5.1.3 of the analysis also indicates that non-return valves are necessary to minimize the contribution of extraction steam to turbine overspeed. Based on the discussion in Section 5.1.3, Section 10.1.2 of the turbine missile probability analysis (concerning valve inspections and tests) tends to diminish the importance of the non-return valves by stating that the non-return valves are not required to support the assumptions of the analysis. However, this is not correct in that the analysis includes the implicit assumption (albeit non-conservative) that the non-return valves close without failure since the failure of these valves is not modeled. Therefore, GE-ST-56834/P needs to be revised to properly reflect the importance of the extraction non-return valves and to establish or otherwise refer to augmented inspection and testing requirements that are appropriate for these valves. To the extent that this information was extracted from the Original Equipment Manufacturer's turbine missile generation probability calculation, this error needs to be corrected so the information is properly reflected by the COL in the turbine missile probability analysis (COL Item 10.2-2-A).

Additional Staff comments for XI:

[NRC] understanding is that the power assist non-return valves are needed to keep the turbine from exceeding 120% rated speed due to the energy that is available in the feed water heaters even if the turbine steam admission valves close. If the turbine exceeds this 120% design rating threshold, there is some probability that a tubine missile will be generated (with increased probability as the turbine speed approaches the destructive overspeed limit). Hence, [NRC] view that the model is assuming that the non-return valves close thereby eliminating this part of the turbine missile probability

consideration. Additionally, it seems to [NRC] that the turbine vibrations that result if the non-return valves are not credited in the turbine missile probability calculation will also increase the probability of turbine missiles. [NRC] would think that the assumption that the non-return valves close is an important consideration in the turbine missile probability calculation from one or both of these perspectives.

GEH Response:

From the MPA report: 5.1.3 Extraction systems
Extraction systems differ in the amounts of energy ......[some material removed].........
The closing time of the extraction non-return valves is sufficient to minimize extraction steam contribution to the turbine overspeed event. ......[some material removed]........
The model is concerned with turbine overspeed caused by load loss with valves stuck such that the trip system cannot function. An overspeed event caused by a stuck check valve, allowing steam to feed back from extraction processes is excluded from the probability model. Although the entrained energy associated with a stuck extraction line check valve is not inconsequential; it is not included in this assessment as the entrained energy associated with load loss and stuck MS/CV and CIVs is considered more limiting for overspeed calculations. [end]

The predominant failure mechanism for overspeed is when high pressure main steam valves or reheat valves are stuck open. MPA report has (in section 5.1.6):
The model considers the three simultaneous conditions necessary to occur to result in an overspeed event:

1) Loss of Load,
2) Failure of the Primary and Emergency Overspeed Trip system, and
3) Failure of the Control system, which results in driving the control valves open.

One or more stuck non-return valves do not overspeed the turbine, but assist in acceleration if a pair of steam admission valves are stuck open. GEH does not see in the report where the word "necessary” was used.

MPA report section 10.1.2 is written:

10.1.2 In-service Inspection of Turbine Valves

All main stop valves, control valves, extraction non-return valves important to overspeed protection (although not specifically required to support the assumptions of the missile probability analysis), intermediate stop, and intercept valves are tested under load. [end]

Which states that extraction non-return valves are not required to support the assumptions (leading to calculations) of the MPA report. Thus GE-STG had done studies (or calculations) that indicate if all of the steam main path valves were closed the turbine would not destructively overspeed from reverse flow of extraction steam flashing.

The installation of non-return valves are mainly for asset protection from moisture entrainment and as a reduction element of turbine speed acceleration in case of critical pair of valve failures.

Some extractions (and associated feedwater piping and heater volume) have more entrained energy than others. When the extraction can potentially result in an overspeed close to the maximum allowable limit for repeated occurrence (emergency overspeed), the extraction includes one spring assisted non-return valve. The extractions that have the potential to drive the unit above the emergency overspeed are equipped with two (2) spring assisted non-return valves; in series activated by the emergency trip system and thus would require multiple valve or common mode failures. Section 5.1.3 of the MPA report identifies that…"Although the entrained energy associated with a stuck extraction line check valve is not inconsequential; it is not included in this assessment as the entrained energy associated with load loss and stuck MS/CV and CIVs is considered more limiting for overspeed calculations."

Specific volume of the feedwater heaters was not known at the time when the overspeed/entrained energy assessment was performed. However, using similar size turbine data, assuming that all but one of the extraction lines fail open (this one (#5) being the open feedwater heater lines), the overspeed contribution would be 4-5% which does not lead to destructive overspeed. The worst-case condition of the extractions is when there is a failure of the #5 extraction non-return valve that would result in a continuous supply of steam expanding thru the LP. This is consistent with the peak overspeed of event #7 of GE-ST-56834/P Table 7.2 as compared to the overspeed value of event #1 for the MS/CV and CIVs remaining open.

Using the event numbers in the MPA report Tables 5-1, 5-3 and 7-2, event 1 results in the highest speed. This speed is still about 11% below the calculated destructive overspeed.

The 120% overspeed event is not considered since it will not release a blade outside of the turbine. A blade does not penetrate the inner casing. Only a large wheel disc part liberated from the shaft can potentially exit the turbine case and this is at the calculated destructive overspeed way in excess of the 120% factory spin test speed stated in DCD 10.2.3.5 bullet 5.

Reference also DCD 10.2.1.3, 10.2.2.4 and 10.2.3.4 wording:
The overspeed trip setpoint of the turbine is approximately 110% (of rated speed) This overspeed trip setpoint is at least 1% above the highest anticipated speed resulting from loss of load, which is normally in the range of 106-109%. The turbine assembly is designed and tested to withstand the stresses corresponding to an overspeed level of

120%. This speed is approximately 10% above the highest anticipated speed resulting from loss of load. The final overspeed basis and setpoints are included with the turbine missile probability analysis (Subsection 10.2.3.8).

[and]

The turbine missile probability analysis discussed in Subsection 10.2.3.8 includes an analysis of turbine component loading. The analysis includes rotor and blade loading combinations. The analysis shows that the rotor and blades have adequate margin to withstand loadings imposed during postulated overspeed events up to 120% of rated speed without detrimental effects.

Thus the 4 -5% overspeed contribution can be discounted for the worse case of overspeed events seeing that we are still about 11% below the destructive overspeed event. GE-STG nuclear turbines have a wide margin in all safety aspects.

DCD Impact:

None

Staff's comment XII:

Tier 1 Table 2.11.4-1: The proposed discussion under Items 1 and 2 of the table states that "This includes equipment, structures, systems, or components (SSCs), listed in (1) above. This is confusing as to which (1) is being referred to, especially in Item 2, and this statement should be clarified to state: "...listed under Item (1) of Section 2.11.4."

[NRC] think that this approach would also eliminate the confusion

GEH Response and DCD Impact:

Tier 1 Subsection 2.11.4 has been revised to include a new table with the list of SSCs that comprises the RTNSS Category B.

Staff's comment XIII:

The following editorial changes are needed to ensure clarity in the design basis:

a. End of Tier 2 Section 6.6.7, under Maintenance and Inspection Program: Revise second sentence to state: "For example, equipment important to turbine overspeed protection and referred to in COL Information Item 10.2-1-A, should be included."

b. Tier 2 page 10.2-8, 4th paragraph: Combine/revise the last two sentences to state: "…and implementation of inspection, maintenance, and testing programs as referred to in COL Information Items 6.6-1-A and 10.2-1-A."

c. Tier 2 page 10.2-11, 2nd paragraph: Revise the last sentence to state: "Non-return valves are inspected and tested in accordance with vendor recommendations as discussed in Subsections 6.6.7 and 10.2.3.7 and as specified by COL Information Items 6.6-1-A and 10.2-1-A."

d. Tier 2 page 10.2-15, last under Section 10.2.3.6: Revise the last sentence to state: "…identified in Section II of SRP 3.5.1.3, and to address any augmented valve and control system maintenance, inspections, and tests that are needed (COL 6.6-1-A and 10.2-1-A).

e. Tier 2 page 10.2-19, COL Information Item 10.2-1-A: Revise the first sentence to state: "…identified in Section II of SRP 3.5.1.3, and to address any augmented valve and control system maintenance, inspections, and tests that are needed (Section 10.2)…"

<u>GEH Response and DCD Impact:</u>

Each of the requested items in Staff comment XIII have been incorporated into the DCD Section 10.2 or DCD Subsection 6.6.7.

On item XIII.e the “(Section 10.2)” was deleted because it did not provide any further information since this COL Information item is in DCD Section 10.2.

<u>Included it this GEH response:</u>

DCD Subsection 3.5 revises DCD Figure 3.5-2 by deleting the building “DS” from the turbine missile zone. This was committed to in RAI 10.2-18 S02.

<u>DCD Impact</u>:

The revised DCD Figure 3.5-2 is included in Enclosure 2.

For historical purposes, the original text of RAI 10.2-18 and the GE response are included.

NRC RAI 10.2-18

DCD Section 10.2.2.4 describes the functionality and protection provided by the primary and emergency trip systems, including provisions for redundancy and reliability.

(A) Describe how the overspeed protection system provides diversity (e.g. mechanical trip device) as recommended in SRP Section 10.2.

(B) Provide a detailed description of the emergency trip fluid system and discuss its reliability, to ensure adequate performance, when either the primary or the emergency trip system actuates, thus closing all stop, control and combined intermediate valves.

(C) Discuss design provisions for single failure and common cause failure that could prevent the emergency trip fluid from performing its intended function.

(D) *Provide approximate percentage of rated speeds for systems actuation as described in SRP 10.2, Rev 2 (July 1981), Subsection III, Paragraphs 2(b), 2(c) and 2(d).*

GE Response

(A) A triple and redundant system, as described in Subsection 10.2.2.4, paragraphs 3, 4, and 5 replace the mechanical trip device. The diversity is provided through the Primary and Emergency systems. Redundancy is further provided for by using three (3) separate speed signals for the Primary Trip and speed control systems, and three (3) additional speed signals for the
Emergency trip system.

(B) The 8th paragraph, 10th paragraph, and 11th paragraph of Subsection 10.2.2.4 provides a detailed description of the fail safe closure provisions that ensure closure of all steam valves required to protect the turbine from overspeed, even with failure of both the systems due to loss of all power to the hydraulic systems.

(C) The design provisions that prevent single cause and common cause failure from preventing closure of the steam valves is discussed in detail in paragraph 11 of Subsection 10.2.2.4.

(D) The COL Unit Specific Information, Subsection 10.2.5.2, Turbine Design Overspeed, will provide the approximate percentage of rated speeds for systems actuation as described in SRP 10.2, Rev 2 (July 1981), Subsection III, Paragraphs 2(b), 2(c), and 2(d).

NRC RAI 10.2-18 S01

Reference: GE response Letter MFN-06-154, dated June 12, 2006, which addressed NRC RAI Letter No. 23, dated May 3, 2006

ESBWR DCD Section 10.2.2.4 describes the functionality and protection provided by the primary and emergency trip systems, including provisions for redundancy and reliability. In RAI 10.2-18, the staff requested that the applicant describe how the overspeed protection system provides diversity (e.g. mechanical trip device) as recommended in SRP Section 10.2.

In GE letter MFN-06-154, dated June 12, 2006, the applicant stated the following:

A triple and redundant system, as described in Subsection 10.2.2.4, paragraphs 3, 4, and 5 replace the mechanical trip device. The diversity is provided through the Primary and Emergency systems. Redundancy is further provided for by using three (3) separate speed signals for the Primary Trip and speed control systems, and three (3) additional speed signals for the Emergency trip system.

The response to RAI 10.2-18 is not acceptable as the proposed design exhibits redundancy but not diversity. In operating plants, the mechanical trip provides a diverse trip mechanism, which eliminates common cause failures associated with electrical components, and thereby increases reliability of the turbine overspeed function.

Therefore, the applicant's proposed deviation from the criterion specified in SRP Section 10.2, Rev. 2 must be justified if any structures, systems or components (SSCs) important to safety are vulnerable to turbine missiles, or if the turbine missile effects could otherwise pose a challenge to plant operators in achieving and maintaining safe shutdown conditions. For example, a situation that could pose a challenge to plant operators is a turbine missile strike on a hazardous chemical or flammable liquid storage tank.

The applicant's justification should include the following information:

1. A complete listing of turbine missile vulnerabilities that exist of the nature described above, including a diagram showing locations relative to the turbine placement to facilitate NRC review.
2. Potential consequences of turbine missile strikes on the SSCs identified in item 1 above.
3. A comparison of the reliability of the proposed turbine overspeed trip protection capability to the reliability that is afforded by the diverse capability that exists in operating plants.
4. Provide a failure modes and effects analysis for the proposed turbine overspeed protection equipment. Specifically identify and address any common mode or common cause failure vulnerabilities that exist.

5. Compare the likelihood of generating turbine missiles with the turbines to be used in the new plants, with the likelihood of turbine missile generation in current plants that have diverse turbine overspeed trip capability.
6. Provide a summary discussion of what the overall consequences are of eliminating the diverse turbine overspeed trip capability on plant safety, taking into consideration the above factors.

GE Response

The probability of low-trajectory turbine missile generation from overspeed events is dependent on the design, maintenance, and test frequency of the Primary and Emergency Overspeed Protection systems. Historically, nuclear turbines were equipped with an electrical overspeed trip (Primary) and a separate and diverse mechanical overspeed trip (Emergency). The ESBWR turbine is equipped with an electrical Primary Overspeed Protection system and a separate and diverse electrical Emergency Overspeed Protection system in lieu of the mechanical overspeed trip to improve reliability. Following are responses to the six items requested in RAI 10.2-18 Supplement 1.

1. *A complete listing of turbine missile vulnerabilities that exist of the nature described above, including a diagram showing locations relative to the turbine placement to facilitate NRC review.*

As discussed in DCD Subsection 10.2.4, the safety related SSCs potentially located in the turbine missile low-trajectory strike zone consist of:

- Reactor Protection System (RPS) input devices from the condenser pressure sensors and turbine bypass valve position switches (and associated cabling) and
- Reactor Feed Pump (RFP) breakers.

The turbine missile discussion is included in DCD Section 3.5 and Subsection 10.2.4. Figure 3.5-2 shows the ESBWR low-trajectory turbine missile strike zone, corresponding to the strike zone depicted in Regulatory Guide 1.115, Figure 1. This figure provides the relative locations of structures and essential systems (as defined in RG 1.115) with respect to the strike zone. DCD Subsection 10.2.4 contains details on the safety related SSCs that may potentially be located in the low-trajectory turbine missile strike zone. Exact locations are to be identified as part of the detailed design.

In regard to missile strikes to hazardous chemicals or flammable liquids, Regulatory Guide 1.115, Regulatory Position C.1 states that consideration may be limited to the structures, systems, and components listed in the Appendix to Regulatory Guide

1.117. Item 14 in the Appendix to Regulatory Guide 1.117 requires protection of those portions of SSCs whose failure could result in incapacitating injury to occupants of the control room. In general, hazardous and flammable chemicals are not provided with protection from either low trajectory turbine missiles or externally generated (i.e. tornado) generated missiles. Fire Protection system and control room habitability design features are provided to minimize the potential for "incapacitating injury to occupants of the control room" without the need for missile protection for the storage area. Onsite hazardous chemicals related to control room habitability are addressed in DCD Section 6.4. Design features of the Fire Protection system are described in DCD Subsection 9.5.1.

2. *Potential consequences of turbine missile strikes on the SSCs identified in item 1 above.*

Refer to DCD Subsection 10.2.4 for this information. As stated above, the equipment consists of RPS input devices and the RFP breakers.

The equipment within the RPS is designed to fail to a trip-initiating state on loss of power, loss or disconnection of any input signal, or loss of any internal or external device-to-device connection signal as discussed in DCD Subsection 7.2.1.2.4. A missile strike to one of these devices, or its interconnection, results in the affected RPS channel(s) transferring to the fail-safe trip condition.

The RFP breakers are required to open under feedwater line break conditions inside containment as described in DCD Subsection 7.7.3.1.1. The location of these breakers is not final and they may be located in the strike zone. In this case, the RFP breakers are to be provided with protective barriers as described in Regulatory Guide 1.115 to prevent a missile strike.

3. *A comparison of the reliability of the proposed turbine overspeed trip protection capability to the reliability that is afforded by the diverse capability that exists in operating plants.*

The ESBWR main turbine electronic overspeed control methodology is both redundant and diverse. Redundancy comes from use of multiple speed probes and multiple processing cores (controllers), extending through to the trip solenoid valve level. The turbine hydraulic trip solenoid valve hydraulic circuits are arranged in a dual, "2-out-of-3" (2/3), de-energize to trip configuration. Any power interruption to either set of the 2/3 trip solenoid valves results in a turbine trip. Diversity is provided by separate sets of physically isolated primary and emergency overspeed protection controllers. The primary overspeed trip and emergency overspeed trip controllers are independent and diverse by providing unique hardware and logic design and implementation. Primary overspeed protection is through application code, while emergency overspeed protection is through controller level “factory defined” firmware coding. Power to the trip solenoids is interrupted by either the primary overspeed protection controllers, or by the emergency overspeed protection controllers. An overspeed trip results if either set of redundant controllers determines an overspeed condition exists. Power interruption to the turbine control cabinet (which also supplies power to the trip solenoids) results in a “fail-safe” turbine trip. The trip solenoid valve and associated controller are fully testable during normal operation.

For an actual overspeed trip condition, the primary overspeed controllers exchange and vote their individual speed inputs so each core executes its protective algorithm on the consensus speed value. After code execution, each primary overspeed controller de-energizes associated relays in a 2-out-of-3 mechanical relay tree, one tree each for the 3 trip solenoids. The 2/3 trip contact vote precludes a single failure in any of the 3 controllers from blocking trip initiation. The contacts of this relay tree are independent from the emergency overspeed controllers, and operate on one leg of the power circuit to each of the trip solenoid valves. The primary overspeed controllers act to de-energize the trip solenoid valves independent of the emergency overspeed controllers.

A different implementation and operation takes place in the three completely separate and individual emergency overspeed trip controllers. Each of the three emergency controllers has a dedicated power supply and operates completely separate from each of the other emergency overspeed trip controllers. The three emergency controllers also operate independently from the primary overspeed trip controllers. In the event of an overspeed condition, the emergency controllers individually detect, determine, and de-energize relays in a 2-out-of-3 mechanical relay tree – one tree each for the three trip solenoids. The contacts of this relay tree control the leg of the power circuit to each of the trip solenoid valves opposite from the primary overspeed controllers. The emergency overspeed controllers act to de-energize the trip solenoid valves independent of the primary overspeed controllers.

As stated in DCD Subsection 10.2.3.4, the overspeed trip setpoint of the turbine is approximately 110%. This overspeed trip set point is at least 1% above the highest anticipated speed resulting from loss of load, which is normally in the range of 106-109%. The turbine assembly is designed and tested to withstand the stresses corresponding to an emergency overspeed level of 120%, which is approximately 10% above the highest anticipated speed resulting from loss of load.

The probability of an overspeed event with this fully electronic overspeed protection system is less likely than previous mechanical-electrical based overspeed protection systems. Validation information comes from a fleet that has amassed over 18 million operating hours with no known failure of the electronic trip system to protect the machine from the occurrence of an overspeed event. Probability of turbine overspeed is a factor in the Turbine Missile Probability Report that is to be provided as required by DCD Tier 1 ITAAC 2.11.4.

4. Provide a failure modes and effects analysis for the proposed turbine overspeed protection equipment. Specifically identify and address any common mode or common cause failure vulnerabilities that exist.

Turbine controls upgrades have been performed on some of the existing Boiling Water Reactor (BWR) fleet. The upgrades have successfully eliminated the mechanical overspeed trip feature from these operating units. Units with this upgrade are similar to the proposed ESBWR arrangement. In support of these GE MK-VI Turbine Control system upgrades, a Failure Modes and Effects Analysis (FMEA) was completed.

IEC-61508, Functional safety of electrical/electronic/programmable electronic safety-related systems, methodology is globally accepted for electronic safety-related controls applications. IEC-61508, part 6 has an accepted methodology for computing common mode failures as a function of the predicted failure rate of each of the components. In addition, since common mode failures are considered the critical driver to turbine overspeed protection system failure, special attention is given to determining their probability. Therefore, the IEC-61508 methodology was selected and applied to quantify the common mode failure probability used in the missile probability assessments.

The predicted Primary and Emergency Overspeed Protection system failures are dominated by undetectable common mode failures. The results of the IEC-61508 analysis indicated a Beta of 1% for the controls and 2% for the I/O and trip solenoids. This means that 1% (or 2%) of the sum of component failure rates for all parts in the protection system represent the common mode failure probability. Of this percentage, 1% is not expected to be detectable. The Beta values are computed from a design assessment-using table D.1 in IEC-61508-6 Annex D.

The FMEA prepared for the MK-VI Turbine Controls upgrade may not specifically apply to the final ESBWR turbine overspeed protection system design. However, the methodology and results are expected to be similar to those described above. When the detailed design of the ESBWR turbine overspeed protection system is complete, an FMEA will exist and the results will be used as an input in the low-trajectory turbine missile probability computation.

5. Compare the likelihood of generating turbine missiles with the turbines to be used in the new plants, with the likelihood of turbine missile generation in current plants that have diverse turbine overspeed trip capability.

The design value for the ESBWR turbine missile probability is less than or equal to 10^{-5} per turbine year as stated in DCD Subsection 10.2.1. This value compares favorably with the value of 10^{-4} based on historical failure data stated in Regulatory Guide 1.115.

6. Provide a summary discussion of what the overall consequences are of eliminating the diverse turbine overspeed trip capability on plant safety, taking into consideration the above factors.

Low trajectory turbine missile protection is provided by multiple features including:

- Turbine orientation and placement,
- Turbine rotor design,
- Material selection and processing,
- Metallurgical stability in rotors and blades,
- Quality assurance in design and fabrication,
- Preservice inspections and testing,
- Inservice inspections and testing, and
- Redundant overspeed protection systems.

Turbine orientation and placement provides a high degree of confidence that low-trajectory missiles resulting from turbine failures will not damage essential systems (essential systems as defined in Regulatory Guide 1.115). The ESBWR has a favorably oriented turbine as discussed in DCD Section 3.5. The NRC guidance suggests a low trajectory turbine missile probability of less than 10^{-4} is acceptable for turbines with favorable orientation. The design value for the ESBWR turbine is less than 10^{-5} per turbine year as stated in DCD Subsection 10.2.1.

The probability of a low trajectory turbine missile is a combination of the probability of a missile for turbine speeds up to 120% (of rated speed) and the probability of a missile for turbine speeds greater than 120%. The probability of the turbine speed reaching a level approaching 120% is assumed to be 1.0; the failure of the normal speed control system is assumed to be certain. The probability of the turbine speed ever exceeding 120% is a function of the design, maintenance and test frequency of the speed control and Primary and Emergency Overspeed Protection systems.

Run-away overspeed events (>120%) are only possible with concurrent failure of the normal speed control system (discrete speed monitoring devices, normal speed controller, turbine main control and intercept valves) and overspeed protection system (separate speed monitoring devices, overspeed trip function, and fast-closing steam stop and control valves). The reliability of these systems, including redundancy and diversity, is analyzed based on component evaluation and historical operating experience, with the result factored into the overall missile probability analysis. The periodic inspection, testing and maintenance requirements for the turbine, turbine valves and overspeed protection systems are specified, as required, to maintain the assumed probability throughout the life of the plant.

Based on the above discussion and evaluations required for the Turbine Missile Probability Report, the modern electrical overspeed trip offers at least equal protection against run-away overspeed events as the mechanical-electrical overspeed trip provided on some operating units. The Turbine Missile Probability Report is to be provided as required by DCD Tier 1 ITAAC 2.11.4.

DCD Impact

No DCD changes will be made in response to this RAI.

NRC RAI 10.2-18 S02, including revision 1

With respect to minimizing the potential for generation of turbine missiles due to turbine overspeed, in RAI 10.2-18 S01, the staff requested that GEH provide: (1) a complete listing of turbine missile vulnerabilities that exist, including a diagram showing locations relative to turbine placement, and (2) a list of potential consequences of turbine missile strikes on the structures, systems, and components (SSCs) identified in Item (1).

In a letter dated June 7, 2007, GEH addressed the potential impact of turbine missiles on safety-related equipment. However, this response does not fully address the staff's acceptance criteria which is the basis for the RAI. As discussed in Standard Review Plan (SRP) Section 3.5.2, "Structures, Systems, and Components to be Protected from Externally Generated Missiles," acceptance is based on the design meeting the guidelines of Regulatory Guide (RG) 1.115, "Protection Against Low-Trajectory Turbine Missiles." RG 1.115 states that "Essential systems of a nuclear power plant should be protected against low-trajectory turbine missiles due to failure of main turbine generator sets. Consideration may be limited to the structures, systems, and components listed in the Appendix to Regulatory Guide 1.117, "Tornado Design Classification." Therefore, in addition to the safety-related equipment that was addressed in the June 7 response to RAI 10.2-18 S01, the staff requests that GEH update the response to parts (1) and (2) of the RAI to address the other items that are listed in the Appendix to RG 1.117, including a determination as to whether turbine missile barriers are warranted for any of these items along with the basis for this determination; and whether or not any of the vulnerable SSCs include equipment that is subject to regulatory treatment of non-safety systems (RTNSS), Category B. The NRC staff also requests that GEH revise the DCD for the ESBWR accordingly to reflect the complete scope and results of this evaluation in the plant licensing basis, and to establish combined license action items and inspections, tests, analyses, and acceptance criteria as appropriate.

GEH Response

Equipment listed as Regulatory Treatment of Non-Safety Systems (RTNSS) Category B, listed in Table 19A-2 and 19A-3 15 functions and the essential structures, systems, and components referred to in Regulatory Guide 1.115, Revision 1, and the Regulatory Guide 1.117, Revision 1, 14 Appendix Structure, Systems, and Components, have been reviewed and are not within the low-trajectory turbine missile zone as shown in Design Control Document (DCD) Figure 3.5-2. The review is outlined below:

The definition of a Low-Trajectory Turbine Missile Strike Zone as described in NRC Regulatory Guide 1.115, Revision 1, and shown in RG 1.115 Figure 1 is the bounding area listed as “an area bounded by lines inclined at 25 degrees to the turbine wheel planes and passing through the end wheels of the low-pressure stages (see Figure 1)”. This has been translated into the DCD as Figure 3.5-2.

This DCD Figure (3.5-2) is used to evaluate the location of safety-related equipment and SSCs, RTNSS Criterion B SSCs and RG 1.117 Appendix SSCs.

RG 1.117 Appendix SSCs are to be reviewed for potential turbine missile strikes in place of the “Tornado Design Classification” based upon the regulatory position “C” in RG 1.115, Revision 1.

RG 1.115 has three main considerations:

- The integrity of the reactor coolant pressure boundary
- The capability to shut down the reactor and maintain it in a cold shutdown condition, or
- The capability to prevent accidents that could result in potential offsite exposures that are a significant fraction of the guideline exposures of 10 CFR Part 100, "Reactor Site Criteria. (For ESBWR: 10 CFR 52.47 offsite dose concerns)

These three considerations are also embodied in RTNSS Criterion B and in RG 1.117. Therefore do not need to be expressly reviewed in this RAI response.

RTNSS equipment, as listed in DCD Table 19A-2 and 3 (Functions and Structures housing RTNSS functions) are individually evaluated for a potential strike from a Low-Trajectory Turbine Missile as defined in RG 1.115, Revision 1, below.

DCD Section 19A.3 CRITERION B: LONG-TERM SAFETY ASSESSMENT and DCD Subsection 19A.3.1 (Actions Required Beyond 72 Hours) required to be maintained in the long term are:

- Core cooling,
- Containment integrity,
- Control Room habitability, and
- Post-accident monitoring.

The ESBWR is designed so that safety-related passive systems are able to perform all safety functions for 72 hours, after initiation of a design basis event, without the need for active systems or operator actions. After 72 hours, nonsafety-related systems are used to replenish the passive systems or to perform core cooling and containment integrity functions directly. Between 72 hours and seven days, the resources for performing safety functions must be available on-site. After seven days it is reasonable to assume that certain commodities can be replaced or replenished from offsite sources, e.g., diesel fuel. Each required safety function must be sustained to ensure that reactor and containment conditions are stable, the operating staff is protected, and the condition of the plant can be monitored. RTNSS SSCs required to perform safety functions after 72 hours have augmented design requirements that provide reasonable assurance they will function when needed. RTNSS B SSCs have redundancy for the active components. They are designed to appropriate seismic design standards and are protected from high winds and flooding hazards. These SSCs that are subject to harsh environmental conditions are also able to perform in accident environmental conditions. Each safety function is analyzed below to identify nonsafety-related systems that are required after 72 hours. These systems are candidates for RTNSS.

From DCD Table 19A-2 (RTNSS Functions for Criterion B) the following SSCs are in the scope to address long-term safety and seismic requirements:

1. **RTNSS Criterion B FPS (Fire Protection System) Diesel Driven Pump**
The diesel driven fire pump is located internal to the Fire Pump Enclosure (FPE) that is between the two Firewater Storage Tanks (FWS) as shown on DCD Figure 1.1-1, 3.5-2 or Figure 9A.2-33. The fuel oil for this diesel is also stored in this same building but in a separate enclosure (see item 8 below). The DCD excerpt below confirms the location:

> 3G.4.3 Structural Description
> The FWSC [Fire Water Storage Complex] consists of two Firewater Storage Tanks (FWS) and a Fire Pump Enclosure (FPE) that share a common basemat. Each FWS is capable of storing 2082 m3 (550000 gallons) of water. The FPE provides enclosure and protection for the Electric Pump, RPV Makeup Water Pump, Diesel Pump, Tank Recirculation Pump, and Diesel Fuel Oil Storage Tank.

As shown on DCD Figure 3.5-2 the location of the FWSC is outside the Low-Trajectory Turbine Missile Strike Zone defined in Regulatory Guide 1.115 and therefore does not require any turbine missile protection barriers.

2. **RTNSS Criterion B Motor Driven Pump**
The motor driven fire pump is located internal to the fire pump enclosure that is part of the FWSC. See item 1, above, for structural description. As shown on DCD Figure 3.5-2 the location of the FWSC is outside the Low-Trajectory Turbine Missile Strike Zone, as defined in Regulatory Guide 1.115, and therefore do not require any turbine missile protection barriers.

3. RTNSS Criterion B FPS to FAPCS Connection Piping

The Fuel and Auxiliary Pools Cooling System (FAPCS) piping to the Isolation Condenser/Passive Containment Cooling System (IC/PCCS) pools or Reactor Coolant Inventory Makeup Pump are run in conjunction with the piping runs for the primary firewater system lines. FAPCS pump is located in the Fire Pump Enclosure. The following DCD excerpts confirm the locations:

9.5.1.1 Design Bases

The ESBWR FPS design bases incorporate the following elements: (12th bullet)

- To provide a post-accident source of makeup water for IC/PCCS pools and Spent Fuel Pool through piping connections to the Fuel and Auxiliary Pools Cooling System (FAPCS). FPS components located outside the [Reactor Building] RB supporting FAPCS makeup are designed to Seismic Category I standards and will not fulfill a fire protection function. Fire hydrants, stand pipes, or other large lines do [will] not be attached to the dedicated portion of the FPS designed to provide long term makeup to pools in the RB.

9.5.1.4 Fire Protection Water Supply System

Figure 9.5-1 provides a simplified diagram of the primary firewater supply piping and supply piping for ESBWR Standard Plant facilities supported by the secondary firewater supply piping yard loop.

Water Source (Third paragraph):

The primary, Seismic Category I, firewater storage tanks and Seismic Category I diesel pump and fire protection piping provide post-accident makeup water to the IC/PCCS pools and Spent Fuel Pool using FAPCS piping. FPS components located outside the RB supporting FAPCS makeup will not fulfill a fire protection function. Fire hydrants, stand pipes, or other large lines will not be attached to the dedicated portion of the FPS designed to provide long-term makeup to pools in the RB. This portion of the FPS is RTNSS rather than safety-related because the pools have sufficient capacity, such that makeup is not required until after 72 hours. The primary firewater storage tanks have sufficient capacity to meet the total demand from 72 hours up to 7 days. After 7 days, onsite or offsite makeup sources can be used. A deviation from acceptance criterion II.1.a of SRP 9.1.3 (which requires Quality Group C for Spent Fuel Pool makeup components) is provided in Table 1.9-9. This deviation is acceptable because this function is not required until after 72 hours. RTNSS requirements on the components performing the nonsafety-related makeup water function assure reliability which also justifies the change from Quality Group C to D. Post-accident reactor inventory makeup is provided via a dedicated FAPCS pump located in the Fire Pump Enclosure.

Equipment Locations are shown on DCD Figure 3.5-2 and piping is depicted on DCD Figure 9.5-1. Since all of the required piping and equipment is outside the Low-Trajectory Turbine Missile Strike Zone, as defined in Regulatory Guide 1.115, and therefore do not require turbine missile protection barriers.

4. **RTNSS Criterion B Passive Autocatalytic Recombiners (PAR)**
The PARs are located inside of containment, which is located inside of the Reactor Building. PARs do not require powered therefore they are self-contained. The Reactor Building is located south of the turbine building as shown on Figure 1.1-1 or 3.5-2 and are thus outside the Low-Trajectory Turbine Missile Strike Zone, as defined in Regulatory Guide 1.115, and therefore do not require any turbine missile protection barriers.

5. **RTNSS Criterion B Passive Containment Cooling System (PCCS) Vent Fans**
Located also inside of Containment the PCCS Vent Fans are powered from Ancillary Diesel. Both of which are outside of the Low-Trajectory Turbine Missile Strike Zone, as defined in Regulatory Guide 1.115, as shown on DCD Figure 1.1-1 and therefore does not require turbine missile protection barriers.

6. **RTNSS Criterion B Emergency Lighting Units**
As per DCD Table 19A-3 RTNSS Criterion B emergency lighting is restricted to the Control Building and discussed in other parts of the DCD as required for the control room and the emergence shutdown panels. This is further discussed in DCD Subsection 9.5.3.3.3.1. Other emergency lighting is discussed in DCD subsections 9.5.3.3.3 and 9.5.3.3.3.2, but these are for self-contained battery units and not part of RTNSS Criterion B functions. This is also referenced in DCD Table 3.2-1 (R15) Item 2 and note: (5) h, also as per DCD Subsection 9.5.3.3.3.

The power for these lights comes from the safety-related (DCD Rev.6, Subsection 9.5.3.4) DC batteries for the first 72 hours and ancillary AC power beyond 72 hours as per DCD, Rev. 6, Subsection 19A.3.1.4. Therefore since the control building, safety-related DC batteries and ancillary diesels are located south of the turbine building Emergency Lighting, per Table 19A-3 will not be affected and therefore do not require turbine missile protection barriers.

7. **RTNSS Criterion B FPS Water Tank**

The Fire Protection System primary Fire Water Storage (FWS) tanks are shown on DCD Figure 3.5-2. By definition of a Low-Trajectory Turbine Missile Strike Zone as described in NRC Regulatory Guide 1.115, Revision 1, and shown in RG 1.115 Figure 1 is the bounding area listed as "an area bounded by lines inclined at 25 degrees to the turbine wheel planes and passing through the end wheels of the low-pressure stages (see Figure 1)". This has been translated into the ESBWR DCD as Figure 3.5-2. Therefore the FPS Water Tanks are outside Low-Trajectory Turbine Missile Strike Zone, as defined in Regulatory Guide 1.115, and therefore do not require any turbine missile protection barriers.

INPO SIGNIFICANT EVENT REPORT (SER) 1-09 documents a potential for loss of fire water from a turbine incident. A turbine liberating the last three stages of blades caused the event. This generated enough vibration that the firewater header in the turbine building ruptured, emptying the firewater storage tank. To preclude this situation, the ESBWR standard plant is designed with a primary fire water system that is dedicated to the Seismic Category 1 buildings with a separate secondary fire protection loop supplying the yard piping. This secondary loop is specified in Combined Operating License (COL) information items 9.5.1-1-A and 9.5.1-2-A. The divisions of the fire protection loops are shown on DCD Figure 9.5-1. The two fire protection sub-systems are isolated from each other with closed isolation valves so that each system can operate individually and separately. The primary loop cannot be diverted into the secondary loop without operator action. Therefore, even with an unlikely loss of piping in the yard loop, the RTNSS functions of the primary system are unaffected.

8. <u>RTNSS Criterion B FPS Diesel Fuel Oil Tank</u>

The fuel oil for this diesel is also stored in the fire pump enclosure that is part of the FWSC, but in a separate room. There is sufficient fuel oil in the tank so transfers are not required from the main fuel oil storage tanks. See the DCD excerpts below:

> 9.5.1.4 Fire Protection Water Supply System
> The fuel oil tank for the primary diesel-driven fire pump has a capacity based on supporting the RTNSS function of the fire pump to provide makeup water to the IC/PCCS pools from 72 hours to seven days after an accident. Because the flowrate required for performing the RTNSS function is less than the flowrate required for supplying firewater, the diesel-driven pump need not operate continuously to supply the required quantity of makeup water to the pools. The fuel capacity required before tank refilling is based on fuel consumption for injecting the required makeup quantity versus operation of the diesel engine for approximately 96 hours. A fuel oil capacity of 3.79 m^3 (1000 gallons) satisfies this requirement.

9A.4.11 Fire Pump Enclosure
The Fire Pump Enclosure is a Seismic Category I structure that contains the primary fire pumps and fuel oil tank. The fire pumps have RTNSS functions. This building does not contain any other systems or functions that could affect the operation or shutdown of the reactor, nor does it contain any significant hazards. However, fuel oil tanks for the Seismic Category I diesel fire pump are located within the Fire Pump Enclosure.

The FWSC is outside the Low-Trajectory Turbine Missile Strike Zone, as defined in Regulatory Guide 1.115, and therefore does not require turbine missile protection barriers.

9. <u>RTNSS Criterion B Ancillary Diesel Generators</u>

Located along the turbine axis and south of the turbine building as shown on DCD Figure 1.1-1, they are well outside of the Low-Trajectory Turbine Missile Strike Zone defined in Regulatory Guide 1.115. See the DCD excerpt below for confirmation:

9.5.4.2 System Description
<u>Ancillary Diesel Generators</u> (ADG)
The two ancillary diesel generators, ADG-A and ADG-B, are each housed in a separate enclosure in the ADB, a seismic category II structure. The generator units and the loads they provide are discussed in Subsection 8.3.1.1.9. Each ADG has its own day tank, which holds sufficient fuel oil to support operation of its corresponding ADG set. Each ADG has its own dedicated fuel oil storage tank which holds sufficient fuel oil to operate its corresponding ADG a minimum of seven days without refueling.

Since the ADGs are outside the Low-Trajectory Turbine Missile Strike Zone, as defined in Regulatory Guide 1.115, thus they do not require turbine missile protection barriers.

10. <u>RTNSS Criterion B Ancillary AC Power Busses</u>

The Ancillary Diesel Generator building which includes the electrical busses are located along the turbine axis and south of the turbine building as shown on DCD Figure 1.1-1, therefore well outside of the Low-Trajectory Turbine Missile Strike Zone defined in Regulatory Guide 1.115. Thus, RTNSS electrical busses do not require turbine missile protection barriers. Reference DCD excerpt:

8.3.1.1.9 Ancillary AC Diesel Generators
Two nonsafety-related ancillary diesel generators provide post accident power to the loads designated on Figure 8.3-3 when no other sources of power are available. Refer to Appendix 19A for further discussion of the

ancillary diesel generator augmented design requirements. The ancillary diesel generators are Seismic Category II, as are their associated auxiliaries, controls, electrical buses, and fuel oil tanks. (See Subsection 9.5.4 for discussion of fuel oil tanks.) The diesels and associated equipment are housed in a Seismic Category II structure. The ancillary power is not required to support safety-related loads for the first 72 hours following the loss of all other AC power sources. See Figure 8.3-1 Sheet 1 for the isolated ancillary power connection to safety-related loads.

11. RTNSS Criterion B Ancillary Diesel Generator Fuel Oil Tanks

The Ancillary Diesel Generator Fuel Oil Tanks are located in the Ancillary Diesel Generator Building which is aligned with turbine axis and south of the turbine building, as shown on DCD Figure 1.1-1, the Ancillary Diesel Generator building is well outside of the Low-Trajectory Turbine Missile Strike Zone defined in Regulatory Guide 1.115. See the DCD excerpts below for confirmation:

9.5.1.12.1.5 Ancillary Diesel Fuel Oil Tank Capacity within Building
The capacity of each of the ADG day tanks will not exceed 4164 L (1100 gallons); however, the main fuel oil storage tanks for these diesels will exceed this capacity. The main fuel oil storage tanks are located in separate fire areas in the ADB; in close proximity to the ADGs, but separated by 3-hour rated fire barriers.

Technical Justification: The ESBWR design includes two independent and physically separated nonsafety-related ADGs capable of providing the electrical load as described in Subsection 8.3.1.1.9 and shown in Figure 8.3-3. Neither ADG is necessary to achieve and maintain safe shutdown conditions for the 72-hour period following an accident or fire event. Each fuel oil storage tank is located in the ADB [Ancillary Diesel Building] in a dedicated three-hour fire rated compartment. There is no safety-related equipment located in the same building as the fuel oil tank rooms. Additionally, the fuel oil tank rooms are located in individual fire areas adjacent to the ADG rooms and are positioned such that the three-hour fire rated walls, ceiling, and floor of the fuel oil storage tank room are not common to the other redundant ADG.

9.5.4.2 System Description
Ancillary Diesel Generators
The two ancillary diesel generators, ADG-A and ADG-B, are each housed in a separate enclosure in the ADB, a seismic category II structure. The generator units and the loads they provide are discussed in Subsection 8.3.1.1.9. Each ADG has its own day tank, which holds sufficient fuel oil to support operation of its corresponding ADG set. Each ADG has its own dedicated fuel oil storage tank which holds sufficient fuel oil to operate its

corresponding ADG a minimum of seven days without refueling. [These are shown in DCD Figure 9.5-9a]

Since the ADGs fuel oil tanks are outside the Low-Trajectory Turbine Missile Strike Zone, as defined in Regulatory Guide 1.115, thus they do not require turbine missile protection barriers.

12. RTNSS Criterion B Ancillary Diesel Generator Fuel Transfer Pumps

The Ancillary Diesel Generator Fuel Transfer Pumps are located in the Ancillary Diesel Generator Building which is aligned with turbine axis and south of the turbine building, as shown on DCD Figure 1.1-1, the Ancillary Diesel Generator building is well outside of the Low-Trajectory Turbine Missile Strike Zone defined in Regulatory Guide 1.115. See the DCD excerpt below for confirmation:

> 9.5.4.1 Design Bases
> Ancillary Diesel Generators
> The ADG fuel oil storage and transfer system is not safety-related and has no safety-related design basis.
>
> The ADG fuel oil storage and transfer system has RTNSS functions, as a supporting system to provide power. These functions are described in Appendix 19A, which provides the level of oversight and additional requirements to meet the RTNSS functions. Performance of RTNSS functions is assured by applying the augmented design standards described in Subsection 19A.8.3.
> Each of the two ADGs is provided as a complete skid-mounted package. A separate, dedicated, fuel oil storage and transfer system is provided for each ADG. Thus, the ADG fuel oil storage and transfer system is not required to be designed with redundancy nor defense-in-depth principles applied.

Since the ADGs fuel oil transfer pumps are outside the Low-Trajectory Turbine Missile Strike Zone, as defined in Regulatory Guide 1.115, they do not require turbine missile protection barriers.

13. RTNSS Criterion B Ancillary Diesel Building Heating, Ventilation and Air Conditioning (HVAC)

The Ancillary Diesel Building is located along the turbine axis and south of the turbine building as shown on DCD Figure 1.1-1; therefore well outside of the Low-Trajectory Turbine Missile Strike Zone defined in Regulatory Guide 1.115, thus the HVAC for this facility does not require turbine missile protection barriers.

14. RTNSS Criterion B Control Room Air Handling Units

The Control Building is located as per DCD Figure 1.1-1, which can also be seen on DCD Figure 3.5-2. Both figures clearly show the building well outside of the Low-Trajectory Turbine Missile Strike Zone, as defined in Regulatory Guide 1.115. Therefore this building does not require turbine missile protection barriers.

15. RTNSS Criterion B Air Conditioning for air handling unit coils and the Q-DCIS Room Local Coolers

The air conditioning units for the Control Building are located at the Control Building. The Control Building is shown on DCD Figure 1.1-1 and can also be seen on Figure 3.5-2. Both figures clearly show the Control Building well outside of the Low-Trajectory Turbine Missile Strike Zone defined in Regulatory Guide 1.115. Therefore this building and the air conditioning for air handling unit coils do not require turbine missile protection barriers.

Regulatory Guide 1.117 (RG 1.117)

NRC requested in this RAI (10.2-18 S02) to evaluate the equipment listed in Regulatory Guide 1.117 Appendix for required missile barriers from Low-Trajectory Turbine Missile Strike Zone defined in Regulatory Guide 1.115. The following 14 line items are from the RG 1.117 Appendix, including the Notes. Below each of the 14 items are reviewed and each contains the GEH response:

Regulatory Guide 1.117 Appendix item 1: The reactor coolant pressure boundary. [Note 1]

The reactor pressure boundary is confined to the Reactor Building and it is located along the turbine axis south of the turbine building as can be seen in DCD Figure 3.5-2. Thus with the turbine favorable oriented, there are no items in the Low-Trajectory Turbine Missile Strike Zone defined in Regulatory Guide 1.115 and thus turbine missile barriers are not required

Regulatory Guide 1.117 Appendix item 2: Those portions of the main steam and main feedwater systems [Note 2] in PWRs up to and including the outermost isolation valves.

Since this requirement is defined for a Pressurized Water Reactor (PWR) it does not apply. If it were to apply to BWRs, all ESBWR B21 safety-related main steam lines and drains are located along the turbine axis in the Seismic Category I Steam Tunnel portion of the Reactor Building. Thus with the turbine favorable oriented, there are no safety-related main steam piping items in the Low-Trajectory Turbine

Missile Strike Zone defined in Regulatory Guide 1.115. The ESBWR feedwater lines are located mostly along the turbine axis south in the turbine building and on the elevations below the turbine. Feedwater is not used to for the RTNSS Criterion B functions of Core Cooling, Containment Integrity, Control Room Habitability, or Post-accident monitoring. Thus with the turbine favorable oriented, there are no items in the Low-Trajectory Turbine Missile Strike Zone that require turbine missile barriers.

Regulatory Guide 1.117 Appendix item 3: The reactor core and individual fuel assemblies, at all times, including during refueling.

The reactor core is confined to the Reactor Building and it is located along the turbine axis south of the turbine building as shown in DCD Figure 3.5-2. Thus with the turbine favorable oriented, the core is not in the Low-Trajectory Turbine Missile Strike Zone defined in Regulatory Guide 1.115 and thus turbine missile barriers are not required.

Regulatory Guide 1.117 Appendix item 4: Systems or portions of systems that are required for (1) attaining safe shutdown, (2) residual heat removal, (3) cooling the spent fuel storage pool, (4) mitigating the consequences of a tornado-caused PWR steam line break, [Note 3] (5) makeup water for the primary system, and (6) supporting the above systems, e.g., cooling water, ultimate heat sink, air supply, auxiliary feedwater, and ventilation.

The system functions and support systems, listed above are located in the Reactor Building or are located along the turbine axis south in the turbine building. Other essential systems defined as RTNSS Criterion B are reviewed in the first portion of this RAI. The discussion for RTNSS Criterion B systems and the general design of the ESBWR precludes that the above items (RG 1.117, Appendix item 4) being located in the nonsafety-related Turbine Building. The PWR items will be excluded from this discussion since the ESBWR is a Boiling Water Reactor (BWR) facility. Thus with the turbine favorable oriented, the Reactor Building, Control Building, Fuel Building, FWSC and the ADG building are not in the Low-Trajectory Turbine Missile Strike Zone, as defined in Regulatory Guide 1.115, and thus turbine missile barriers are not required.

Regulatory Guide 1.117 Appendix item 5: The spent fuel storage pool, to the extent necessary to preclude significant loss of watertight integrity of the storage pool and to prevent missiles from contacting fuel within the pool.

Spent Fuel pools are located in the Reactor Building or Fuel Building and are located along the turbine axis south of the turbine building as shown in DCD Figure 1.1-1 or 3.5-2. Thus with the turbine favorable oriented, the spent fuel is not in the Low-

Trajectory Turbine Missile Strike Zone defined in Regulatory Guide 1.115 and thus turbine missile barriers are not required.

The Independent Spent Fuel Storage Installation also appears on DCD Figure 3.5-2 as potentially in the Low-Trajectory Turbine Missile Strike Zone as defined in Regulatory Guide 1.115, but is shown only as a representative generic building for the ESBWR standard plant. DCD Subsection 3.5.1.1.1.2, proposed revision, attached with this RAI response, states that the Independent Spent Fuel Storage Installation will not be in the low-trajectory turbine missile strike zone. Therefore turbine missile barriers will not be required at the Independent Spent Fuel Storage Installation.

<u>Regulatory Guide 1.117 Appendix item 6</u>: The reactivity control systems, e.g., control rod drives and boron injection system.

Reactivity control systems including the boron injection system are located in the Reactor Building, and it is located along the turbine axis south of the turbine building as shown in DCD Figure 1.1-1 or 3.5-2. With the turbine favorably oriented, the Reactor Building and Control Building are not in the Low-Trajectory Turbine Missile Strike Zone defined in Regulatory Guide 1.115. Thus, turbine missile barriers are not required.

<u>Regulatory Guide 1.117 Appendix item 7</u>: The control room, including all equipment needed to maintain the control room within safe habitability limits for personnel and safe environmental limits for tornado-protected equipment.

With respect to turbine missiles the control room and associated sub systems are located almost due southeast of the turbine building as shown in DCD Figure 1.1-1 and 3.5-2. Figure 3.5-2 shows that the Control Building is not in the Low-Trajectory Turbine Missile Strike Zone defined in Regulatory Guide 1.115. Thus turbine missile barriers are not required.

<u>Regulatory Guide 1.117 Appendix item 8</u>: Those portions of the gaseous radwaste treatment system whose failure due to tornado effects could result in potential offsite exposures in excess of the criterion given in subitem (3) of the regulatory position.

For Regulatory Guide 1.117 Appendix item 8, only the offgas charcoal tank could potentially contain a radioactive source large enough to contend with the 10 CFR 100 offsite dose concerns (For ESBWR: 10 CFR 52.47 offsite dose concerns). Reference ESBWR DCD subsections 11.3.3, 11.3.4, 11.3.7, 12.2.1.3 and Tables

11.3-4 through 11.3-7. The offgas system is shown in DCD Figure 11.3-1. The other parts of the offgas system or turbine building HVAC systems are piping or ducts and do not contain radioactive sources in sufficient quantity and thus would not require protection from turbine missiles. Reference DCD 12.2.3.4.

The HVAC system of the turbine building (TB) is a clean system and does not contain any "sources" of radioactivity. It is only a conduit pathway to off-site exposures if a source was released, for example a main steam line rupture. The TB HVAC filters are installed only to capture dust that may have become contaminated and are not considered a source. The turbine building HVAC is monitored to ensure no radioactivity, outside of the guidelines, is emitted to the surroundings. Thus if a turbine missile destroyed HVAC duct work, filter banks or the monitors there could only be a release of some steam that came from the source and this would be well under the off-site release dose limits. The HVAC system does not release any more radioactivity than is emitted from the source of the incident.

The remainder of the offgas system is also just piping and equipment that carries entrained air and minor trace radioactive gases (e.g. N-16) from the condenser to the adsorber tanks in question. If a turbine missile were to impact any other portion of the Offgas system, such as Steam Jet Air Ejectors or Hydrogen Recombiners, (other than the adsorber tanks) only a few gasses from the condenser would be released to the turbine building general areas. These gases are so low in concentration and radioactivity (plus most have very short half lives) that they are not considered a source that could impact the off-site release dose limits.

The off-gas charcoal tanks, of the Off Gas System (OGS), are located along the turbine axis north in the turbine building more than 35° out of the vertical plane of the last turbine bucket. The off-gas charcoal tank covers are depicted in DCD Figure 1.2-14. DCD Figure 3.5-2 shows that the north end of the Turbine Building is not in the Low-Trajectory Turbine Missile Strike Zone, as defined in Regulatory Guide 1.115, and thus turbine missile barriers are not required.

<u>Regulatory Guide 1.117 Appendix item 9</u>: Systems or portions of systems that are required for monitoring, actuating, and operating tornado-protected portions of systems listed in items 4, 6, 7, and 13.

The monitoring, actuating and operating portions of systems listed in RG 1.117 Appendix items 4, 6, 7 and 13 are centralized in the Control building, which is a seismic category 1 structure. The review of this structure is above in RG 1.117 item 7. It has been reviewed that the portions of systems required for operations and post accident monitoring (including emergency lighting in the control building) are protected from Low-Trajectory Turbine Missile Strikes, as defined in Regulatory Guide 1.115, and thus turbine missile barriers are not required. Also see Regulatory Guide 1.117 Appendix item 4, 6, 7, and 13 for disposition of each RG 1.117 Appendix item incorporated in this RAI response.

Regulatory Guide 1.117 Appendix item 10: All electric and mechanical devices and circuitry between the process sensors and the input terminals of the actuator systems involved in generating signals that initiate protective actions by tornado-protected portions of systems listed in items 4, 6, 7, and 13.

Safety Related components from the Reactor Protection System (RPS) that are potentially in the Low-Trajectory Turbine Missile Strike Zone, as defined in Regulatory Guide 1.115 are listed in DCD 10.1 and 10.2.4. These Reactor Protection System instruments listed in DCD CH 10.1 and 10.2.4 have been evaluated as acceptable since they fail-safe. Fail-safe refers to failing into a trip-initiating state on loss of power, loss or disconnection of any input signal, or loss of any internal or external device-to-device connection signal (reference DCD Subsection 7.2.1.2.4). Accordingly, damage to the safety-related condenser pressure transmitters and turbine bypass valve position sensors and any associated cabling and connections as the result of low-trajectory turbine missiles does not inhibit the safety-related function of the RPS. Therefore, turbine missile protection with barriers is not relevant to these affected safety-related SSCs. Other signals required for RG 1.117 items 4, 6, 7 and 13 or RTNSS Criterion B are generated, or processed, in buildings (Reactor Building, Control Building, Fuel Building, FWSC and the ADG building) outside the Low-Trajectory Turbine Missile Strikes, as defined in Regulatory Guide 1.115, and thus turbine missile barriers are not required. Also see Regulatory Guide 1.117 Appendix item 4, 6, 7, and 13 for disposition of each RG 1.117 Appendix item incorporated in this RAI response.

Regulatory Guide 1.117 Appendix item 11: Those portions of the long-term emergency core cooling system that would be required to maintain the plant in a safe condition for an extended time after a loss-of-coolant accident.

This is reviewed in the RTNSS portion of this RAI response above under #3 for FAPCS pump suction piping and # 7 FPS water supply. It has been reviewed that the portions of systems required for operations and post accident monitoring RG 1.117 item numbers 4 (systems), 7 (Control Room), and 9 (monitoring and actuating) are not within the Low-Trajectory Turbine Missile Strikes, as defined in Regulatory Guide 1.115, and thus turbine missile barriers are not required.

Regulatory Guide 1.117 Appendix item 12: Primary reactor containment and other safety-related structures, such as the control room building and auxiliary

building, to the extent that they not collapse, allow perforation by missiles, or generation of secondary missiles, any of which could cause unacceptable damage to tornado-protected items. However, the primary containment need not necessarily maintain its leaktight integrity.

The Reactor Building, Control Building, FWSC, ADG, and other safety-related structures are basically south of the turbine building as per DCD Figures 1.1-1 and 3.5-2. Thus they are not in the Low-Trajectory Turbine Missile Strike Zone, as defined in Regulatory Guide 1.115, and do not require turbine missile barriers.

Regulatory Guide 1.117 Appendix item 13: The Class 1E electric systems, including the auxiliary systems for the onsite electric power supplies, that provide the emergency electric power needed for the functioning of plant features included in items 1 through 11 above.

Class 1E electric systems, including the auxiliary systems for the onsite electric power supplies, that provide the emergency electric power needed for the functioning of plant features for the ESBWR are very limited because this plant is designed to be passive. The DC and associated A/C Class 1E electrical systems reside in the reactor, control and associated safety-related buildings. These structures are basically south of the turbine building as per DCD Figures 1.1-1 and 3.5-2. Thus they are not in the Low-Trajectory Turbine Missile Strike Zone, as defined in Regulatory Guide 1.115, and do not require turbine missile barriers.

Regulatory Guide 1.117 Appendix item 14: Those portions of structures, systems, and components whose continued function is not required but whose failure could reduce to an unacceptable safety level the functional capability of any plant features included in items 1 through 13 above or could result in incapacitating injury to occupants of the control room.

The answers to RG 1.117 Appendix questions 1 to 13 are answered above and are supplemented by the responses to the 15 RTNSS Criterion B items listed in DCD Chapter 19A also answered in this RAI response.

Items in the postulated Low-Trajectory Turbine Missile Strike Zone defined in Regulatory Guide 1.115 are shown in DCD Figures 3.5-2. These include parts of Radwaste Building, main fuel oil tanks, turbine lube oil dirty and clean tanks, auxiliary boiler house, condensate storage tank and the Electrical building, which contains the TSC. All of these structures are nonsafety-related and do not require control room staff to occupy for RTNSS Criterion B or safety-related accident mitigation purposes. Therefore, incapacitating injuries to an occupant of the control room is not expected and thus will not require turbine missile barriers. The

Independent Fuel Storage Installation was reviewed under RG 1.117 item 5 (spent fuel).

Notes: [from RG 1.117 Appendix]

1. **As defined in §50.2 of 10 CFR Part 50.**
2. **The system boundary includes those portions of the system required to accomplish the specified safety function and connecting piping up to and including the first valve (including a safety or relief valve) this is either normally closed or capable of automatic closure when the safe function is required.**
3. **Alternatively, the main steam system, up to and including a second isolation valve such as a redundant series MSIV, or a turbine stop valve, may be protected.**

GEH will revise the Design Control Document (DCD) Sections 3.5.1.1.1.2, 10.1 and 10.2.4 to include information that states the standard ESBWR design, with its favorably oriented turbine, does not require turbine missile barriers for RTNSS Category B functions, RG 1.115 or RG 1.117 Appendix essential structures, systems or components.

GEH will do a general revision to DCD Figure 3.5-2 to clearly indicate that the Independent Spent Fuel Storage Installation is not in the Low-Trajectory Turbine Missile Strike Zone defined in Regulatory Guide 1.115. This figure will also be revised to be in conformance with DCD Figure 1.1-1 and 9A.2-33. A proposed mark-up of DCD Figure 3.5-2 is not included with this RAI response, but will be revised in DCD Revision 7.

GEH will revise DCD Table 19A-3 to delete the duplicate entry of "CRHAVS Air Handling Units" and insert the correct item "Ancillary Diesel Building HVAC"

In conclusion, the DCD proposed mark-ups with the existing DCD statements should make it clear that RTNSS Category B functions as listed in DCD Table 19A-2 and 19A-3, and structures, systems and components listed in the Regulatory Guide 1.117 Appendix are not within the low-trajectory turbine missile strike zone as defined in Regulatory Guide 1.115 and shown in DCD Figure 3.5-2. Therefore barriers to protect this equipment, or the safety-related equipment listed in DCD Section 10.2, from low-trajectory turbine missile strikes are not required. No new COL information items are required for the ESBWR standard plant DCD. Since there are no new requirements to be verified, new or revised Inspections, tests, Analyses, and Acceptance criteria (ITAAC) are not required.

DCD Impact

Proposed markups of the DCD change are attached.

Enclosure 2

MFN 10-089 Revision 1

Response to NRC Request for

Additional Information Letter No. 409

Related to ESBWR Design Certification Application

DCD Markups for RAI Number 10.2-18 S03

Table 1.9-10

Summary of Differences from SRP Section 10

SRP Section	Specific SRP Acceptance Criteria	Summary Description of Difference	Subsection Where Discussed
10.2	5.b – Frequency for surveillance testing of main steam stop and control valves	In accordance with NRC accepted programs at operating plants, the main steam stop and control valves will be tested quarterly instead of once per month.	
10.2	10 CFR Part 50, Appendix A, GDC 4	None	
10.2	RG 1.68	None	
10.2	BTP ASB 3-1	~~None~~ESBWR applies BTP SPLB 3-1, which has replaced BTP ASB 3-1.	Table 1.9-20
10.2	BTP MEB 3-1	~~None~~ESBWR applies BTP 3-4, which has replaced BTP MEB 3-1.	Table 1.9-20
10.2	Paragraph III.2.c	ESBWR uses an alternate overspeed detection and trip system and does not incorporate a mechanical over speed trip device.	10.2.2.4
~~10.2.3~~	~~II.4.a – Turbine design~~ overspeed	~~Design overspeed is less than 5%~~ above the highest anticipated speed from a loss of load	~~10.2.3~~
10.3	10 CFR Part 50, Appendix A, GDC 2	None	
10.3	10 CFR 50, Appendix A, GDC 4	None	
10.3	10 CFR 50, Appendix A, GDC 5	The ESBWR is a single-unit plant. Therefore this Code is not applicable.	N/A
10.3	10 CFR 50, Appendix A, GDC 34	GDC 34 pertains to PWR plants. This is not applicable to the ESBWR design.	N/A
10.3	RG 1.26	None	

10.2 TURBINE GENERATOR

10.2.1 Design Bases

The design of the Turbine Generator (TG) system meets the requirement of General Design Criterion 4 as related to the protection of safety-related structures, systems and components from the effects of turbine missiles. It provides a redundant turbine overspeed protection system to minimize the probability of turbine missile generation. In addition, the ESBWR standard plant design has a favorably oriented turbine to minimize the potential impact on safety-related structures and equipment. Favorably oriented turbine generators are located such that the containment and most safety-related Structures, Systems and Components (SSC) outside containment are excluded from the low-trajectory hazard zone described in Regulatory Guide (RG) 1.115.

The required total turbine missile generation probability for loading the turbine and bringing the system online is less than 1×10^{-4} per year as outlined in Table 3.5-1. With rotor designs that utilize large integral forgings, the total turbine missile generation probability is reduced. For ESBWR, assuming the recommended inspections and tests are conducted at the recommended frequencies, this value is less than 1×10^{-5} per year.

10.2.1.1 Safety Design Bases

The TG does not perform or support any safety-related function, and thus, has no safety design basis. The TG is, however, a potential source of high energy missiles that could damage safety-related ~~equipment or structures~~ or RTNSS Category B SSCs. The turbine is designed to minimize the possibility of failure of a turbine blade or rotor. Turbine integrity is discussed in Subsection 10.2.3. The effects of potential high energy missiles are discussed in Section 3.5 and Subsection 10.2.4.

10.2.1.2 Non-Safety Power Generation Design Bases

- The TG has base load and load following capability.
- The gross generator outputs at ESBWR standard plant reactor rated thermal power and Valves Wide Open operation are given on the heat balances shown on Figures 10.1-2 and 10.1-3, respectively.
- The TG load change characteristics are compatible with the Plant Automation System (PAS), which coordinates TG and reactor operation.
- The TG is designed to accept a sudden loss of full load with sufficient margin to the overspeed trip.
- The TG is designed to permit periodic testing under power operation conditions of steam valves important to overspeed protection and overspeed trip circuits.
- The failure of any single component does not cause the rotor speed to exceed 120% of rated speed.

- Turbine control functions, which are required for turbine protection, possess sufficient redundancy such that failure of a single component input does not disable the turbine protection system.
- The TG is designed to accommodate greater than or equal to 85% of rated steam flow through three control valves. Reference DCD Subsection 15.2.2.1.2.
- The TG auxiliary systems (stator cooling, lube oil cooling, etc.) are designed either with enough redundancy to support full power operation with a single failure or to provide a signal to the main control room to prompt a reduction in power to within the capability of the remaining auxiliary systems.

10.2.1.3 Functional Limitations Imposed by the Design or Operational Characteristics of the Reactor Coolant System

Turbine main steam stop, control valves, intermediate stop valves, ~~and~~ intercept valves and non-return valves protect the turbine from excessive speeds. The Steam Bypass and Pressure Control (SB&PC) System protects the reactor system from abnormal pressure surges. Operation of the SB&PC system is discussed in Subsection 7.7.5. The valve arrangements and valve closure times are such that a failure of any single valve to operate does not result in the unit exceeding 120% of rated speed or an abnormal pressure surge in the event of a TG trip signal or near full load rejection.

10.2.1.3.1 Turbine Stop Valve

During an event resulting in turbine stop valve fast closure, turbine inlet steam flow is not reduced faster than that shown in Figure 10.2-1 to comply with the transient analyses in DCD Chapter 15.

10.2.1.3.2 Turbine Control Valve

During any event resulting in turbine control valve fast closure, the turbine inlet steam flow is not reduced faster than that shown in Figure 10.2-2 to comply with the transient analyses in DCD Chapter 15.

The turbine control valve steam flow shutoff rate, upon a step reduction to zero in pressure regulation flow demand (no resulting bypass steam flow demand), is within the region shown in Figure 10.2-3 to comply with the transient analyses in DCD Chapter 15. Any single control system failure or TG event does not cause a faster steam flow reduction than that shown in Figure 10.2-3 without generating control valve fast closure signals to the RPS.

10.2.1.3.3 Load Maneuvering Capability

During at least 90% of an operating cycle, the plant shall be capable of a 24-hour load cycle with the following profile: starting at 100% power, power ramps down to 50% power in two hours, power remains at 50% for two to ten hours, and then ramps up to 100% in two hours. Power remains at 100% for the remainder of the 24-hour cycle. This capability assumes ramp rates up to about ± 0.5% per minute. The plant design shall accommodate a minimum of 17200 equivalent daily load following cycles. Less aggressive load following capability will be available when fuel preconditioning requirements do not support these ramp rates, e.g., for a few days after reload core startup or a control rod pattern exchange.

10.2.2 Description

10.2.2.1 General Description

The TG consists of an 188.5 rad/s (1800 rpm) turbine, external moisture separator/reheaters, generator, exciter, controls, and associated subsystems.

The turbine for the ESBWR standard plant consists of a double-flow, high pressure unit, and three double-flow low pressure units in tandem. The high pressure turbine exhaust gets ~~has extraction points for~~ reheat and sent to the low pressure turbine sections. The high pressure turbine also ~~ing steam and~~ has extractions for high pressure feedwater heating.

Moisture separation and reheating of the high pressure turbine exhaust steam is performed by external Moisture Separator Reheaters (MSRs). The MSRs are located on each side of the TG centerline. The steam then passes through the low pressure turbines, each with extraction points for the low pressure stages of feedwater heating, and exhausts into the main condenser. In addition to the moisture separators in the external MSRs, the turbine steam path has provisions for removing some additional moisture and routing it to extraction lines.

The generator is a direct driven, three-phase, 60 Hz, 188.5 rad/s (1800 rpm) synchronous generator with a water-cooled armature winding and hydrogen-cooled rotor.

The TG uses a digital monitoring and control system, which, in coordination with the SB&PC system, controls the turbine speed, load, and flow for startup and normal operations. The control system operates the turbine stop valves, control valves, and intermediate stop and intercept valves. TG supervisory instrumentation is provided for operational analysis and malfunction diagnosis.

TG accessories include the bearing lubrication oil system, Turbine Generator Control System (TGCS), turbine hydraulic system, turning gear, hydrogen gas control system, seal oil system, stator cooling water system, exhaust hood spray system, turbine gland seal system, MSR reheater heating steam system, excitation system, and turbine supervisory instrument system.

The TG unit and associated high and moderate energy piping, valves, and instruments are located completely within the Turbine Building. Any postulated failure associated with the TG unit does not affect any essential systems or components as defined in BTP SPLB 3-1 or RTNSS Category B functions, as listed in DCD Table 19A-2 and 19A-3, or structures, systems and components listed in Regulatory Guide 1.117 Appendix. Failure of TG equipment cannot preclude safe shutdown of the reactor system. TG system components, equipment, and piping are classified as discussed in Section 3.2.

10.2.2.2 Component Description

The MSRs, MSR drain tanks, stator water coolers, and stator water demineralizer are designed to ASME Code Section VIII requirements. The balance of the TG is designed to turbine manufacturer's standards. All valves important to overspeed protection are designed with closing times sufficient to prevent the turbine from exceeding design overspeed conditions.

10.2.2.2.1 Main Stop and Control Valves

Four main stop and four control valves admit steam to the high pressure turbine. The primary function of the main stop valves is to quickly shut off the steam flow to the turbine under trip conditions. The primary function of the control valves is to control steam flow to the turbine in response to the TGCS, but also close under trip conditions.

The main stop valves are hydraulically operated in an open-closed mode either by the turbine overspeed protection system in response to a turbine trip signal, or by a test solenoid valve and a fast acting solenoid valve for periodic testing. The disks are unbalanced and cannot open against full differential pressure. A bypass is provided to pressurize the below seat areas of the four valves and supply steam for turbine casing and steam chest warming. Springs in the valves are designed to improve the closing time response of the main stop valve under the abnormal conditions listed in Subsection 10.2.2.5. An equalizing header is provided between the stop valves, upstream of the control valves.

Each main stop valve is designed to accept a steam strainer to limit foreign material from entering the control valves and turbine.

The control valves are designed to provide steam shut-off adequate for turbine speed control. The valves are of sufficient size, relative to their cracking pressure, to require a partial balancing.

Each control valve is hydraulically operated by a high pressure fire-resistant fluid supplied through a servo valve.

10.2.2.2.2 High Pressure Turbine

The high pressure turbine receives steam through four steam leads, one from each control valve outlet. The steam is expanded axially across several stages of stationary and moving blades. Extraction steam from the high pressure turbine supplies the sixth stage of feedwater heating and first stage reheaters. High pressure turbine exhaust steam is collected in eight cold reheat pipes, four at each end of the high pressure turbine casing, and is routed to the inlets of the MSRs. Extraction steam taps off the high pressure turbine exhaust cold reheat pipes and is sent to the fifth stage feedwater heater as shown in Figure 10.4-7a.

10.2.2.2.3 Moisture Separator Reheaters

Horizontal, cylindrical-shell, combined MSRs are installed in the steam path between the high and low pressure turbines. The MSRs serve to dry and reheat the high pressure turbine steam exhaust (cross around steam) before it enters the low pressure turbines. This improves cycle efficiency and reduces liquid impingement erosion and flow-accelerated corrosion (FAC) in the low pressure turbines. Cold reheat steam is piped into the bottom of the MSRs. Moisture is removed in chevron-type moisture separators, and is drained to the appropriate stage of feedwater heating. The steam next passes upward across the two reheater stages. Heating steam to the first reheater stage is supplied by extraction steam and heating steam to the second reheater stage is supplied with main steam. Reheated steam is routed to the intermediate stop and intercept valves, which are located just upstream of the low pressure turbine inlet nozzles, Figure 10.3-2. Safety relief valves are provided on the MSRs for overpressure protection. Taps off the cold reheat pipes also supply steam to the fifth stage feedwater heaters.

10.2.2.2.4 Intermediate Stop and Intercept Valves

Hydraulically operated intermediate stop and intercept valves are provided in each hot reheat line just upstream of the low pressure turbine inlet.

Upon loss of load, the intercept valves first close then throttle steam to the low pressure turbine as required to control speed. The intermediate stop valves and intercept valves close on a turbine trip. The intermediate stop and intercept valves are designed to close rapidly to control turbine overspeed.

10.2.2.2.5 Low Pressure Turbines

Each low pressure turbine receives steam from the MSRs through two hot reheat lines. The steam expands axially across several stages of stationary and moving blades.

Extraction steam from the low pressure turbines supplies the first stages of feedwater heating.

10.2.2.2.6 Extraction Non-return Valves

Upon loss of load, the steam contained downstream of the turbine extractions can flow back into the turbine, across the remaining turbine stages, and into the condenser. Associated condensate can flash to steam under this condition and contribute to the backflow of steam or can be entrained with the steam flow and damage the turbines. Non-return valves are employed in selected extraction lines to minimize potential for overspeeding and also for preventing water entrainment (Subsection 10.2.2.4). Two types of non-return valves are provided; spring assisted closure type and simple check valve type. Spring assisted non-return valves are held open with instrument air. The non-return valves close when the parallel relay air dump valves open and vent the air header. When the air is released the spring acts to close the valve. Closure time is within 2 seconds from tripping the relay dump valves. The non-return valves are located on high pressure extraction steam lines to the number five (5) and six (6) feedwater heaters. They are also mounted on extraction lines feeding the open feedwater heater (number four (4)), but two are mounted in series for single failure proof protection since this heater contains a very large volume of water and potential energy. The number three (3) feedwater set, of low pressure heaters, also are required to have the spring-assisted type.

Simple non-return valves are used for the two strings of low-pressure heaters (heater numbers one (1) and two (2)) because of the relative low potential energy for increasing the turbine speed and are not required for turbine overspeed protection. The simple non-return valves on the last two stages of feed water heating are for prevention of moisture carryover and vibrations at low load operation.

The type and location of non-return valves can be adjusted during detailed design when the entrained energy calculations are completed, but must also comply with the missile probability analysis.

The air is supplied by the plant instrument air system.

10.2.2.2.7 Generator

The generator is a direct-driven, three-phase, 60 Hz, 188.5 rad/s (1800 rpm), four-pole synchronous generator with a water-cooled armature winding and hydrogen-cooled rotor.

The rotor is manufactured from forged components and includes layers of field windings embedded in milled slots. The windings are held radially by slot wedges at the rotor outside diameter. The wedge material maintains its mechanical properties at elevated temperature. The magnetic field is generated by direct current (DC) power, which is fed to the windings through collector rings located outboard of the main generator bearings.

The rotor body and shaft is machined from a single, solid steel forging. Detailed examinations include:

- Material property checks on test specimens taken from the forging;
- Photomicrographs for examination of microstructure;
- Magnetic particle and ultrasonic examination; and
- Visual surface finish inspections of rotor slots for indication of a stress riser.

10.2.2.2.8 Hydrogen Gas Control System

The Hydrogen Gas Control System (HGCS) is illustrated on Figure 10.2-4. The HGCS is designed to provide the necessary flow and pressure at the main generator for startup/shutdown filling/purging operations and supply makeup hydrogen for generator leakage during normal operation.

The HGCS consists of hydrogen supply piping with all the necessary valves, instrumentation, gas purity measuring equipment, hydrogen gas dryers, and bulk hydrogen storage unit.

Fires and explosions during filling and/or purging of the generator are prevented by inerting the generator with CO_2 so that a flammable mixture of hydrogen and oxygen cannot be produced. Unneeded hydrogen is vented outside through a flame arrestor.

The bulk hydrogen system utilizes the guidelines given in Reference 10.2-2. Specifically, the bulk hydrogen system piping and components are located to reduce risk from their failures. The bulk hydrogen storage is located outside the Turbine Building at a distance great enough to ensure no structural damage from a hydrogen detonation. The hydrogen lines are provided with a pressure reducing station that limits the maximum flow before entering the Turbine Building. Equipment and controls are designed to be accessible and remain functional after a bulk hydrogen storage detonation. The design features and/or administrative controls are provided to ensure that the hydrogen supply is isolated when normal building ventilation is lost.

The arrangement of buildings at the facility and the location of building doors and bulk hydrogen storage tanks ensure that damage to buildings containing safety-related equipment due to detonation or combustion of hydrogen is unlikely.

Additionally, the bulk hydrogen system piping in the Turbine Building is designed in accordance with industry practice and applicable codes and standards.

10.2.2.3 Normal Operation

During normal operation, the main stop valves, intermediate stop valves, and intercept valves are wide open. Operation of the TG is under the control of the TGCS. The SB&PC system controls the turbine control valves through the TGCS to regulate reactor pressure. The normal function of the TGCS is to generate the position signals for the main stop valves, main control valves, intermediate stop valves, and intercept valves.

10.2.2.4 Turbine Overspeed Protection System

The normal speed control system comprises the first line of defense against turbine overspeed. This system includes the main control valves, intercept valves, and fast-acting valve-closing functions within the TGCS. The normal speed control unit utilizes three speed signals. Loss of any two of these speed signals initiates a turbine trip via the Emergency Trip System (ETS). An increase in speed above setpoint tends to close the control and intercept valves in proportion to the speed increase. Rapid turbine acceleration resulting from a sudden loss of load at higher power levels normally initiates the fast-acting solenoids via the normal speed control system or what is part of the normal/primary overspeed protection and trip system. The fast-acting solenoids rapidly close the main control and intercept valves irrespective of the current turbine speed. A turbine trip signal from the normal/primary system will initiate a closure of all valves important to turbine protection.

The normal speed control system is designed to limit peak overspeed resulting from a loss of full load, to at least 1% below the overspeed trip setpoint. Typically, this peak speed is in a range of 106-109% of rated speed, and the overspeed trip setpoint is approximately 110% of rated speed. All turbine steam control and intercept valves are fully testable during normal operation. The fast closing feature, provided by action of the fast-acting solenoids, is testable during normal operation. The normal speed control system closes all valves important to turbine protection (stop, control, non-return, intermediate stop and intercept valves) if an overspeed event is sensed. The overspeed protection systems (normal/primary and emergency) meet the single failure criterion and are testable when the turbine is in operation. All valves important to turbine protection are capable of closure concurrently. The valve arrangement is such that a failure of any single valve to close will not result in excessive turbine overspeed in the event of a turbine trip signal. This includes the steam non-return check valves provided at extraction connections. Two types of non-return valves are provided, spring assisted closure type and simple check valve type. Spring assisted non-return valves are held open with instrument air and receive a closure signal opening the relay air dump valves. The air is supplied by the plant instrument air system. See DCD Subsection 10.2.2.2.6 for more information.

Hydraulic oil for all steam admission valves and bypass valves are supplied by the electro hydraulic control system. High-pressure oil feed header is routed through the trip manifold assembly. After the trip valve manifold, typically one oil feed line supplies valves of one type, for example stop or control. When a turbine trip signal is present, the feed header dumps its control oil from the trip manifold assembly solenoid valves (either primary and/or emergency) into the electro hydraulic reservoir tank via drain lines from the trip manifold assembly drain pan. Each of the drain lines from the trip manifold drain pan is sized for full oil flow from a trip from both the primary and emergence solenoids and is vented by the drain pan vent.

A turbine trip closes all steam isolation valves (stop, control, intermediate stop and intercept valves) and non-return extraction valves. Either set of solenoids can trip the turbine. The signal that trips the solenoid valves open, to dump the oil, also opens both relay air dump valves for the non-return valves.

Air is dumped from the air relay dump solenoid valves and allow each power operated (spring assisted) non-return valve to close. Each spring assisted non-return valve can be tested individually by venting the air from the piston to the local area via a solenoid test valve. Only the control signals are shared by the two dump systems. Instrument air feed lines are shared by the non-return valves for opening and are shared for dumping the air when the parallel relay dump valves gets an open signal. Testing of these lines and test solenoids each quarter ensure continued uninterrupted operation.

Normal speed control is supplemented by the power load unbalance function. The power load unbalance function can protect the turbine from an overspeed trip condition in the event of full load rejection. The power load unbalance function looks for an unbalance between mechanical power and electrical load. Under specific load rejection conditions, the power load unbalance will initiate main control valve and intercept valve fast closing functions to prevent rapid acceleration and a subsequent turbine trip.

If the normal speed control and power load unbalance function should fail, the overspeed trip devices close all valves important to turbine protection (stop, control, non-return, intermediate stop and interceptthe main and intermediate stop valves). This emergency turbine overspeed protection system comprises the second line of defense against turbine overspeed. It is an independent,both redundant and diverse backup electrical overspeed trip circuit that senses the turbine speed by 3 separate magnetic pickups from the normal/primary over speed trip system and closes all valves important to turbine protection (stop, control, non-return, intermediate stop and intercept valves). The control signals from this emergency circuit are separate from the normal control system and are isolated and independent of one another. There is also a manual turbine trip switch in the control room and one on the front standard of the turbine. The manual switches are tested during refuel outages prior to turbine start-ups or if maintenance work on the wiring could have introduced a potential for loss of continuity or functionality.

Redundancy comes from the use of multiple speed probes (3 normal/primary and 3 emergency without sharing input signals between normal/primary and emergency), multiple separate controllers, and multiple trip solenoid valves. The turbine hydraulic trip solenoid valve hydraulic circuits are arranged in a dual, "two-out-of-three," de-energize to trip configuration. Any power interruption to either set of the two-out-of-three trip solenoid valves in the Emergency Trip Device (ETD) results in a turbine trip.

Diversity is provided by separate sets of physically isolated primary and emergency overspeed protection controllers. The primary overspeed trip and emergency overspeed trip controllers are independent and diverse by providing unique hardware and logic design and implementation. This separate hardware and logic design between the primary and emergency overspeed trip control systems provide redundancy and diversity. Power to the trip solenoids is interrupted by either the primary overspeed protection controllers or by the emergency overspeed protection controllers. An overspeed trip results if either set of redundant controllers determines an overspeed condition exists. Power interruption to the turbine control cabinet (which also supplies power to the trip solenoids) results in a "fail-safe" turbine trip. The trip solenoid valve and associated controller are fully testable during normal operation.

Potential common mode failure and failure modes and effect analysis (FMEA) for the electronic, mechanical and hydraulic portions of this system has been reviewed and documented by the Original Equipment Manufacturer (OEM). Operational Experience (OE) has also been applied to the design and fault tolerance of the turbine overspeed system and valves. OE experience has dictated electro hydraulic system upgrades that have been applied to the ESBWR system; a fluid conditioning system and titanium cooling heat exchanger tubes. Various industry and Nuclear Regulator Commission (NRC) documents are the basis for these evaluations. The culmination of this field data is incorporated in the Missile Probability Analysis (See COL Information item 10.2-2-A) and other associated design documents generated by the Original Equipment Manufacturer. The turbine controller system and turbine overspeed control and trip protection that is provided for the ESBWR has been found to be more reliable than the older electronic and mechanical systems by an order of magnitude.

For an actual overspeed trip condition, the primary overspeed controllers exchange and median vote their individual speed inputs so each controller executes its protective algorithm on the consensus speed value. Values outside the acceptable band are placed automatically into a trip condition. Thus failures of sensing probes (high or low) are eliminated by this voting scheme. Each primary overspeed controller de-energizes trip solenoid valves in a two-out-of-three logic arrangement. The two-out-of-three logic precludes a single failure in any of the three controllers from blocking trip initiation

A different implementation and operation takes place in the three completely separate and individual emergency overspeed trip controllers. Each of the three emergency controllers has a dedicated power supply and operates completely separate from each of the other emergency overspeed trip controllers. The three emergency controllers operate independently from the primary overspeed trip controllers. In the event of an overspeed condition, the emergency controllers individually detect and determine speed, and de-energize trip solenoid valves in a two-out-of-three logic arrangement. The two-out-of-three logic precludes a single failure in any of the three controllers from blocking trip initiation.

The overspeed protection system is designed to ensure that failure of the normal speed control system does not result in turbine speed exceeding 120% of rated speed. The components and circuits comprising the turbine normal and emergency overspeed protection system are testable when the turbine is in operation. Thus common cause failures or degradation mechanisms are canceled out with the ability of on-line testing, multiple separated devices (for example: speed probes, solenoid valves, controllers power supplies, etc), tolerance bands on signal acceptability and redundant valving schemes. Augmented inspection programs required by the turbine missile probability analysis and implementation of the inspection, maintenance, and testing programs as referred to in COL Information items 6.6-1-A and 10.2-1-A also ensures operability.

The overspeed sensing devices are located in the turbine front bearing standard, and are therefore protected from the effects of missiles or pipe breakage. The hydraulic lines are fail-safe; if one is broken, loss of hydraulic pressure results in a turbine trip. The ETD is also fail-safe. Each trip solenoid transfers to the trip state on a loss of control power, resulting in a turbine trip. These features provide inherent protection against failure of the overspeed protection system caused by low trajectory missiles or postulated piping failures.

Each turbine extraction line is reviewed for potential energy and contribution to overspeed. The number and type of extraction non-return valves required for each extraction line are specified based on the enthalpy and mass of steam and water in the extraction line and feedwater heater. Higher energy lines are provided with power-assisted open, spring-assisted closed non-return valves, controlled by air relay dump valves, which in turn, are activated by the ETS. The air relay dump valves, actuated on a turbine trip, dump air from the extraction non-return valve actuators to provide rapid closing via actuator spring force. The closing time of the extraction non-return valves is sufficient to minimize extraction steam contribution to the turbine overspeed event.

The following component redundancies are employed to guard against excessive overspeed:

(1) Main stop valves/Control valves.

(2) Intermediate stop valves/Intercept valves.

(3) Normal speed control/Primary overspeed trip/Emergency overspeed trip.

(4) Fast-acting solenoid valves/Emergency trip fluid system (part of ETD).

(5) Spring assisted non-return valves where needed.

(6) Parallel air relay dump valves for spring assisted non-return valves.

(7) Duel oil drain lines from the trip manifold drain pan to the oil reservoir.

The main stop valves and control valves provide full redundancy in that these valves are in series and have independent control signals and operating mechanisms. Closure of all four stop valves or all four control valves shuts off all main steam flow to the high pressure turbine. The intermediate stop and intercept valves are also in series and have independent control signals and operating mechanisms. Closure of either valve or both valves in each of the six sets of intermediate stop and intercept valves effectively shuts off intermediate steam flow to the three low pressure turbines. This arrangement is such that failure of a single valve to close does not result in turbine speed exceeding 120% of rated speed. To ensure feedwater heater flashing steam does not contribute to acceleration of the turbine after a trip, spring assisted non-return valves are installed on lines that could contain high amounts of entrained energy. Two spring assisted non-return valves are installed in each of the number four (4) feedwater heater extraction lines for single failure proof protection.

10.2.2.5 Turbine Protection System

In addition to the overspeed trip signals discussed, the ETS closes the main stop and control valves and the intermediate stop and intercept valves to shut down the turbine on the following signals.

- Manual e~~E~~mergency trip switch in control room;
- Moisture Separator high level;
- High condenser pressure;
- Low lube oil pressure;
- Low pressure turbine exhaust hood high temperature;

- High reactor water level;
- Thrust bearing wear;
- Manual eEmergency trip switch at the front standard;
- Loss of stator coolant (if runback fails);
- Low hydraulic fluid pressure;
- Selected generator trips;
- Loss of TGCS electrical power;
- Excessive turbine shaft vibration;
- Loss of two speed signals – either two Normal Speed Control or two Emergency;
- Loss of two or more SB&PC System channels; and
- Closure of Main Steam Isolation Valves (MSIVs).

When the ETS is activated, it overrides all operating signals and trips (closes) the main stop, and control valves, and intermediate stop, and intercept valves and non-return valves.

10.2.2.6 Turbine Generator Supervisory Instruments

Although the turbine is not readily accessible during operation, the Turbine Supervisory Instrumentation is sufficient to detect specific turbine generator malfunctions. The Turbine Supervisory Instrumentation includes monitoring of the following:

- Vibration and eccentricity;
- Thrust bearing wear;
- Exhaust hood temperature;
- Oil system pressures, levels and temperatures;
- Bearing metal and oil drain temperatures;
- Shell temperature;
- Valve positions;
- Shell and rotor differential expansion;
- Shaft speed, electrical load, and control valve inlet pressure indication;
- Hydrogen temperature, pressure and purity;
- Stator coolant temperature and conductivity;
- Stator-winding temperature;
- Exciter temperatures;
- Turbine gland sealing pressure;
- Gland steam condenser vacuum;

- Steam chest pressure; and
- Seal oil pressure.

10.2.2.7 Testing

The Primary and Emergency overspeed trip circuits and devices are tested remotely at or above rated speed by means of controls in the Main Control Room (MCR)<u> or can be tested with the turbine not in operation</u>. Operation of the overspeed protection devices under controlled speed conditions is checked at startup and after each refueling or major maintenance outage. In some cases, operation of the overspeed protection devices can be tested just prior to shutdown<u> or on-line</u>. This eliminates the need to test overspeed protection devices during the subsequent startup if no maintenance is performed that affects the overspeed trip circuits and devices.

During refueling, or maintenance shutdowns, coinciding with the inservice inspection schedule required by Section XI of the ASME B&PV Code for reactor components, at intervals defined in Subsection 10.2.3.7, at least one main stop valve, one main control valve, one intermediate stop valve, and one intercept valve are dismantled to conduct visual and surface examinations of valve seats, disks, and stems. If unacceptable flaws or excessive corrosion is found in a valve, all other valves of that type should be dismantled and inspected. Valve bushings are inspected and cleaned, and bore diameters checked for proper clearance.<u> Non-return valves are inspected and tested in accordance with vendor recommendations as discussed in Subsection 6.6.7 and 10.2.3.7 and as specified by COL Information items 6.6-1-A and 10.2-1-A.</u>

<u>The </u>~~Main ~~stop, ~~main ~~control, intermediate stop, and intercept valves are exercised at least ~~once within each calendar quarter (or as required by the turbine missile probability analysis)~~ by closing each valve and observing the remote valve position indicator for fully CLOSED position status. This test also verifies operation of the fast close function of each main stop and main control valve during the last few percent of valve stem travel. Fast closure of the intermediate stop and intercept valves is tested in a similar way if they are required to have a fast close function that is different from the test exercise.

Access to required areas outside of the turbine shielding is provided on the turbine floor under operating conditions.

Provisions are included for testing each of the following devices while the unit is operating:

- ~~Main s~~<u>S</u>top valves and ~~main ~~control valves;
- Low pressure turbine intermediate stop and intercept valves;
- Turbine Extraction non-return valves important to overspeed protection;
- <u>Air relay dump valves;</u>
- ~~Lubricating oil pumps;~~
- Hydraulic fluid pumps;
- Emergency Trip Device; and
- Power-Load Unbalance circuits.

10.2.3 Turbine Integrity

10.2.3.1 Materials Selection

Turbine rotors are made from vacuum treated or remelted alloy steel components using processes that minimize flaw occurrence, assure uniform strength, and provide adequate fracture toughness. Undesirable elements, such as sulfur and phosphorus, are controlled to the lowest practical concentrations consistent with good scrap selection and melting practice, and consistent with obtaining adequate initial and long-life fracture toughness for the environment in which the parts operate. The turbine materials have the lowest Fracture Appearance Transition Temperatures (FATT) and highest Charpy V-notch energies obtainable, on a consistent basis from material at the sizes and strength levels used.

10.2.3.1.1 Materials for Turbine Disc Forgings

Low pressure turbine wheel (disc) forgings are made from vacuum treated Ni-Cr-Mo-V alloy steel forgings. The fracture appearance transition temperature (50% FATT), as obtained from Charpy tests performed in accordance with American Society of Testing Methods (ASTM) A-370, is no higher than -18ºC (0ºF) for low pressure turbine wheel (disc) forgings. The Charpy V-notch energy at the minimum operating temperature is at least 8.3 kg-m (60 ft-lb_f) for a low pressure turbine wheel (disc) forging. A minimum of three Charpy V-notch specimens are tested in accordance with specification ASTM A-370 to determine this energy level. The determination of FATT is used in lieu of nil-ductility transition temperature methods.

10.2.3.1.2 Materials for Integral Rotor Forgings

Large integral rotors are made from vacuum treated Ni-Cr-Mo-V alloy steel forgings. Their larger size limits the achievable properties. The fracture appearance transition temperature (50% FATT), as obtained from Charpy tests performed in accordance with ASTM A-370, is no higher than -1.1ºC (30ºF) for large integral forgings. The Charpy V-notch energy at the minimum operating temperature is at least 6.23 kg-m (45 ft-lb_f) for a large integral rotor forging. A minimum of three Charpy V-notch specimens are tested in accordance with specification ASTM A-370 to determine this energy level.

Current turbine designs utilize rotors produced from large integral forgings. Future turbine designs may include fabricated rotors produced from multiple wrought components. Acceptable material properties will be consistent with component size and fabrication method.

10.2.3.2 Fracture Toughness

Suitable material toughness is obtained through the use of selected materials as described in Subsection 10.2.3.1, to produce a balance of material strength and toughness to ensure safety while simultaneously providing high reliability, availability, and efficiency during operation.

Stress calculations include consideration of centrifugal loads, interference fit, and thermal gradients where applicable. The ratio of material fracture toughness, K_{1c} (as derived from material tests on each major part or rotor), to the maximum tangential stress intensity at speeds from normal to design overspeed, is at least two at minimum operating temperature. The fracture toughness (K_{1c}) value is determined using a value of deep-seated FATT based on the measured FATT values from actual bore specimens or trepan specimens, and a correlation factor obtained from historical integral rotor test data. When required, sufficient warm-up time or other procedures are specified in the turbine operating instructions to ensure that the above ratio of fracture toughness to stress intensity is maintained during all phases of anticipated turbine operation.

10.2.3.3 High Temperature Properties

The operating temperature range of both the high pressure and low pressure rotors is below the stress rupture temperature range of the materials used. Therefore, creep-rupture is not considered to be a significant failure mechanism for these components.

10.2.3.4 Turbine Design

The turbine for the ESBWR standard plant employs integral forgings for the rotors. The integral forging rotor design yields a number of benefits compared to earlier designs with shrunk-on disks. For example, the integral forging rotor is inherently less likely to have a failure resulting in a turbine missile than previous designs with shrunk-on disks and keyways. By eliminating disk bores and keyways, many of the associated stress risers and areas where contaminants collect and concentrate have been eliminated. This design feature minimizes the occurrence of stress corrosion cracking.

The turbine blades are also designed to improve safety and reliability. Some blades in high stress regions utilize axial entry dovetails. This feature allows the designer to optimize the allocation of stress between the blade and rotor dovetail, taking into account the relative strengths of the two materials. Certain blades also incorporate the use of integral covers and mid-span wings. The contact surfaces provided by these features act as frictional dampeners that dissipate vibration energy and reduce the maximum amplitude of vibration. These features also couple the blades into a single structure, raising the natural frequency, thereby reducing the response to flow induced vibration. The end result achieved by incorporation of the above blade design features is decreased vibration and fatigue and enhanced reliability.

The turbine assembly is designed to maintain structural integrity during normal and upset operating conditions including anticipated operational occurrences and accidents resulting in a turbine trip. The design of the turbine assembly meets the following criteria:

- Turbine shaft bearings and pedestals are designed to retain their structural integrity when subjected to any combination of loads from normal and upset operating conditions, anticipated operational occurrences, and accidents resulting in turbine trips.
- The natural lateral critical frequencies of the turbine shaft assemblies existing between zero speed and 120% overspeed are controlled in the design and operation so as to cause no distress to the unit during operation. A torsional vibration analysis shows that the TG rotor resonance is outside of the normal operating frequency and its harmonics.
- The turbine rotor average tangential stress (excluding stresses in the blade/wheel region) at design overspeed resulting from centrifugal forces, interference fit (as applicable), and thermal gradients does not exceed 0.75 of the minimum specified yield strength of the material.
- The overspeed trip setpoint of the turbine is approximately 110% (of rated speed). This overspeed trip setpoint is at least 1% above the highest anticipated speed resulting from

loss of load, which is normally in the range of 106-109%. The turbine assembly is designed and tested to withstand the stresses corresponding to an overspeed level of 120%. This speed is approximately 10% above the highest anticipated speed resulting from loss of load. The final overspeed basis and setpoints are included with the turbine missile probability analysis (Subsection 10.2.3.8).

- Integral forging rotor designs are employed to eliminate adverse effects such as fretting and loosening of discs that are associated with designs that utilize shrunk-on discs.
- Nuclear Boiler System (NBS) chemistry and thus Turbine Main Steam System (TMSS) chemistry are carefully controlled to minimize the potential effects of pitting and stress corrosion cracking of turbine rotors and blades. Expected ESBWR water quality parameters are provided in Table 5.2-5. The expected reactor water quality exceeds the turbine manufacturer's requirements for steam and condensate purity.
- The turbines are built with moisture control features and drain points that remove excessive moisture from the turbine steam path. This design feature, combined with moisture separation and reheat capability provided by the external Moisture Separator Reheaters (MSRs), limits the effects of moisture-related erosion damage to the turbine blades, casings, and rotors. Collected moisture is discharged via extraction point connections to feedwater heaters or through drains to the condenser.
- The turbine missile probability analysis discussed in Subsection 10.2.3.8 contains additional description of the design features of the turbine, rotor, shaft, couplings, and blades, including the number of stages, blade design, how the blades are attached to the rotor, how the turbine rotor is forged, and pertinent fabrication methods. Informational drawings are included as required to illustrate important design features.
- The turbine missile probability analysis discussed in Subsection 10.2.3.8 includes an analysis of turbine component loading. The analysis includes rotor and blade loading combinations. The analysis shows that the rotor and blades have adequate margin to withstand loadings imposed during postulated overspeed events up to 120% of rated speed without detrimental effects.

10.2.3.5 Preservice Inspection

The preservice inspection procedures and acceptance criteria are as follows:

- Forgings are rough-machined with minimum stock allowance prior to heat treatment.
- Forgings undergo 100% volumetric (ultrasonic), visual, and surface examinations subject to established inspection methods and acceptance criteria that are equivalent to or more restrictive than those specified for Class 1 components in ASME B&PV Code Sections III and V. Subsurface sonic indications are not accepted if found to compromise the integrity of the unit during its service life. Rotor forgings may be bored to remove defects, obtain material for testing and to conduct bore sonic inspection.
- All steam path surfaces are surface examined before any welding and/or brazing to the finished rotor forging. After welding and/or brazing activities are completed, all steam path surfaces are re-examined with particular attention given to stress risers and welds.

- Specific portions of finish machined rotors, including any bores, keyways, or drilled holes, are subject to magnetic particle test or liquid penetrant examination. Surface indications are evaluated and removed if found to compromise the integrity of the unit during its service life. All flaw indications in keyways and drilled holes are removed.
- Each fully bladed turbine rotor assembly is factory spin-tested at 120% of rated speed.

Additional preservice inspections include air leakage tests performed to determine that the hydrogen cooling system leakage is within the manufacturer's limits before hydrogen is introduced into the generator casing. The hydrogen purity is tested in the generator after hydrogen has been introduced. The generator windings and required motors are megger-tested. Vibration tests are performed on required motor-driven equipment. Hydrostatic tests are performed on required coolers. Required piping is pressure-tested for leaks. Turbine protection system circuits and hydraulic systems are tested for proper function prior to initial unit startup. The above testing is performed to demonstrate that the TG and related auxiliary systems are available to support power operation.

10.2.3.6 Inservice Maintenance and Inspection of Turbine Rotors

The inservice maintenance and inspection program for the turbine assembly includes the complete inspection of all normally inaccessible parts such as couplings, coupling bolts, turbine shafts, turbine blades and low and high pressure turbine rotors. During plant shutdown (coinciding with the inservice inspection schedule for ASME B&PV Code Section III components, as required by the ASME Boiler and Pressure Vessel Code Section XI), the turbine maintenance and inspection plan is performed in sections during the refueling outages so that a total inspection and any required maintenance have been completed at least once within the time period recommended by the manufacturer. One of the purposes of the inservice maintenance and inspection plan is to detect flaws that could lead to a failure of the rotor assembly or blades at speeds up to 120% of rated speed.

The recommended maintenance and inspection program plan for the turbine assembly, valves and controls ensures that the annual TG missile probabilities are maintained at or below the acceptable level (Subsection 10.2.1).

This inspection consists of visual, surface and volumetric examinations as indicated below.

- Visual, magnetic particle, and ultrasonic examination of all accessible surfaces of rotors.
- Visual and magnetic particle or liquid penetrant examination of all turbine blades.
- Visual and magnetic particle examination of couplings and coupling bolts.

The COL Applicant will provide a description of the plant specific turbine maintenance and inspection program required to satisfy the Original Equipment Manufacturer's turbine missile generation probability calculation including each of the criteria identified in Section II of SRP 3.5.1.3 and to address any augmented valve and control system maintenance, inspections, and tests that are needed ~~(COL 10.2-1-A)~~ (COL 6.6-1-A and COL 10.2-1-A).

10.2.3.7 Inservice Inspection of Turbine Valves

All ~~main~~ stop valves, control valves, extraction non-return valves important to overspeed protection, intermediate stop, and intercept valves are tested under load. Test controls installed in the MCR permit full stroking of the stop valves, control valves, and intermediate stop and intercept valves. Valve position indication is provided in the MCR. Some load reduction may be necessary before testing main stop and control valves, intermediate stop and intercept valves.

Main stop, main control, intermediate stop, and intercept valves are exercised at least once within each calendar quarter (or as required by the turbine missile probability analysis) by closing each valve and observing the remote valve position indicator for fully CLOSED position status. This test also verifies operation of the fast closure function of each main stop and main control valve during the last few percent of valve stem travel. Fast closure of the intermediate stop and intercept valves is tested in a similar way if they are required to have a fast close function that is different from the test exercise.

A tightness test of the main stop and main control valves may be performed as required. A tightness test is normally performed by checking the coast down characteristics of the turbine from no load with each set of four main stop and main control valves closed alternately. As alternative methods, warm up steam may be used as an indicator or the turbine speed may be monitored when on the turning gear while opening each set of four main stop and main control valves alternately.

Non-return valves are internally inspected, as per the augmented valve inspection program, to ensure degradation will not affect gross closure of the valve. See DCD Subsection 6.6.7.

All valves essential to water induction prevention (such as attemperator spray valves, extraction non-return and check valves, etc.) should be tested or inspected for tight shutoff, or an internal visual inspection made. This test should also include all interlocks and controls. All level actuated drain valves should have their level actuated mechanisms tested to be sure they are functioning properly.

All ~~main~~ stop valves, ~~main~~ control valves, and intermediate stop and intercept valves are disassembled and visually inspected once during the first three refueling shutdowns. Subsequent inspections are scheduled as required to support the turbine missile probability analysis and are consistent with applicable industry practice. The inspections are conducted for:

- Wear of linkages and valve stem packing;
- Erosion of valve seats and stems;
- Deposits on stems and other valve parts, which could interfere with valve operation; and
- Distortions, misalignment or cracks.

Non-return valves are inspected per the augmented inspection program and in accordance with vendor recommendations. These inspections include seat to disk contact, binding and wear of linkages, erosion, deposits and other maladies that could disrupt closure operation while at power.

Inspection of all valves of one functional type or size (i.e., stop, control, intercept, non-return) should be conducted for any detrimental unusual condition (as defined by the turbine valve augmented inservice inspection program, see COL 6.6-1-A) if one is discovered during the inspection of any single valve.

10.2.3.8 Turbine Missile Probability Analysis

An analysis is prepared containing an evaluation of the probability of turbine missile generation. The report provides a calculation of the probability of turbine missile generation using approved methods and industry guidance applicable to the fabrication technology employed. The analysis is a comprehensive report containing a description of turbine fabrication methods, material quality and properties, and required maintenance and inspections.

The following information is contained in the above analysis report:

- The calculated probability of turbine missile generation from material and overspeed related failures based on as-built rotor and blade designs and as-built material properties (as determined in certified testing and Nondestructive Examination (NDE));
- Maximum anticipated speed resulting from a loss of load, assuming normal control system function without trip;
- Overspeed basis and overspeed protection trip setpoints;
- Description of the minimum required inservice inspection and testing program for valves essential to overspeed protection; (Subsection 10.2.3.7);
- ~~Discussion of the design and structural integrity of turbine rotors (Subsection 10.2.3.4);~~
- An analysis of potential degradation mechanisms and any specific maintenance or operating requirements necessary to mitigate the effects of such mechanisms, including pitting, low-cycle fatigue, stress corrosion cracking, corrosion fatigue, erosion and erosion-corrosion;
- List of material properties, including the method of obtaining those properties, that includes yield strength, stress-rupture properties, fracture toughness, and minimum operating temperature of the high pressure turbine rotor;
- Additional description of preservice test and inspection procedures and acceptance criteria required to support calculated turbine missile probability;
- Actual maximum tangential and radial stresses and their locations in the low pressure turbine rotor (Subsection 10.2.3.4);
- Rotor and blade design analyses, including loading combinations, assumptions and warm-up time, that demonstrate sufficient safety margin to withstand loadings from postulated overspeed events up to 120% of rated speed; and
- A description of inservice tests, inspections, and maintenance activities for the turbine and valve assemblies that are required to support the calculated missile probability, including inspection and test frequencies with technical bases, type of inspection, techniques, areas to be inspected, acceptance criteria, disposition of reportable indications, and corrective actions, (Subsection 10.2.3.7).

The above analysis/report is prepared using criteria in accordance with NRC requirements that include Reference 10.2-3 and NUREG-0933 item A37.

The COL Applicant will provide an evaluation of the probability of turbine missile generation using criteria in accordance with NRC requirements. If necessary, bounding material property values may be used to perform the analysis until actual material test specimens are available for testing (COL 10.2-2-A).

10.2.4 Evaluation

The turbine generator is nonsafety-related, and is not needed to effect or support a safe shutdown of the reactor.

The turbine is designed, constructed, and inspected to minimize the possibility of any major component failure.

The turbine has a redundant, diverse, and testable overspeed trip system to minimize the possibility of a turbine overspeed event. The turbine controller system and the primary and emergency turbine overspeed trip functions for the ESBWR has been found to be more reliable than the older electronic and mechanical systems by an order of magnitude.

The uncontrolled release of stored energy in the extraction steam system is reduced to an acceptable minimum by the addition of non-return valves in selected extraction lines (Subsection 10.2.2.2.6).

The TG equipment shielding requirements and the methods of access control for required areas of the Turbine Building ensure that the dose criteria specified in 10 CFR 20 for operating personnel are not exceeded. All areas in proximity to TG equipment are zoned according to expected occupancy times and radiation levels anticipated under normal operating conditions. Specification of the various radiation zones in accordance with expected occupancy is listed in Chapter 12. If deemed necessary during unusual occurrences, the occupancy times for certain areas are reduced by administrative controls enacted by health physics personnel.

The design basis operating concentrations of N^{16} in the turbine cycle are indicated in Section 12.2.

The connection between the low pressure turbine exhaust hood and the condenser is made by means of a steel weld or rubber or stainless steel expansion joint. Because there are no essential systems or components (as defined in BTP SPLB 3-1), in the turbine area, and the condenser is at sub-atmospheric pressure during all modes of turbine operation, failure of the joint has no adverse effects on safety-related equipment.

The TG trip logic and control schemes use coincident logic and redundant controllers and input signals to support the plant availability goals and avoid spurious trips.

All safety-related Structures, Systems and Components (SSC) outside containment are excluded from the low-trajectory turbine missile strike zone, as defined in RG 1.115, except:

- Condenser pressure transmitters;
- Turbine bypass valve position sensors; and
- Cabling and connections to the RPS.

The safety-related equipment listed above is potentially within the low-trajectory turbine missile strike zone and subject to direct and indirect effects from turbine missiles. The safety-related condenser pressure transmitters and turbine bypass valve position sensors are part of the safety-related RPS and are therefore classified as safety-related. However, equipment within the

RPS is designed to fail into a trip-initiating state on loss of power, loss or disconnection of any input signal, or loss of any internal or external device-to-device connection signal (Subsection 7.2.1.2.4). Accordingly, damage to the safety-related condenser pressure transmitters and turbine bypass valve position sensors and any associated cabling and connections as the result of low-trajectory turbine missiles does not inhibit the safety-related function of the RPS. Therefore, turbine missile protection is not relevant to these affected safety-related SSCs.

RTNSS Category B functions, as listed in DCD Table 19A-2 and 19A-3, and structures, systems and components listed in Regulatory Guide 1.117 Appendix are not within the low-trajectory turbine missile strike zone as defined in Regulatory Guide 1.115 and shown in Figure 3.5-2. Therefore barriers to protect this equipment, or safety-related equipment listed above from low-trajectory turbine missile strikes are not required.

10.2.5 COL Information

10.2-1-A Turbine Maintenance and Inspection Program

The COL Applicant will provide a description of the plant specific turbine maintenance and inspection program required to satisfy the Original Equipment Manufacturer's turbine missile generation probability calculation including each of the criteria identified in Section II of SRP 3.5.1.3 ~~(Subsection 10.2.3.6).~~, and to address any augmented valve and control system maintenance, inspections, and tests that are needed. These tests and inspections shall ensure required valve closure times and seat leakage requirements are met. The turbine and valve maintenance program and on-line testing programs shall be based upon proper implementation of assumptions and factors contained in Original Equipment Manufacturer's maintenance and testing instructions. The basis for each of the recommendations should be documented and use of operational experience should also be applied to ensure the basis of the calculation forming the results of the Missile Probability Analysis report are continually validated. This basis shall also document the allowed time out of service. All valves important to turbine overspeed protection shall be included, but not limited to, stop, control, non-return, intermediate stop, and intercept valves. The augmented inspection and testing program is covered under COL Information item 6.6-1-A.

10.2-2-A Turbine Missile Probability Analysis

The COL Applicant will provide an evaluation of the probability of turbine missile generation using criteria in accordance with NRC requirements. If necessary, bounding material property values may be used to perform the analysis until actual material test specimens are available for testing (Subsection 10.2.3.8).

10.2.6 References

10.2-1 (Deleted)

10.2-2 Electric Power Research Institute, "Guidelines for Permanent BWR Hydrogen Water Chemistry Installations – 1987," Electric Power Research Institute (EPRI) NP-5283-SR-A, September 1987.

10.2-3 USNRC, "Safety Evaluation Report Relating to the Operation of Hope Creek Generating Station," NUREG-1048, Supplement No. 6, July 1986.

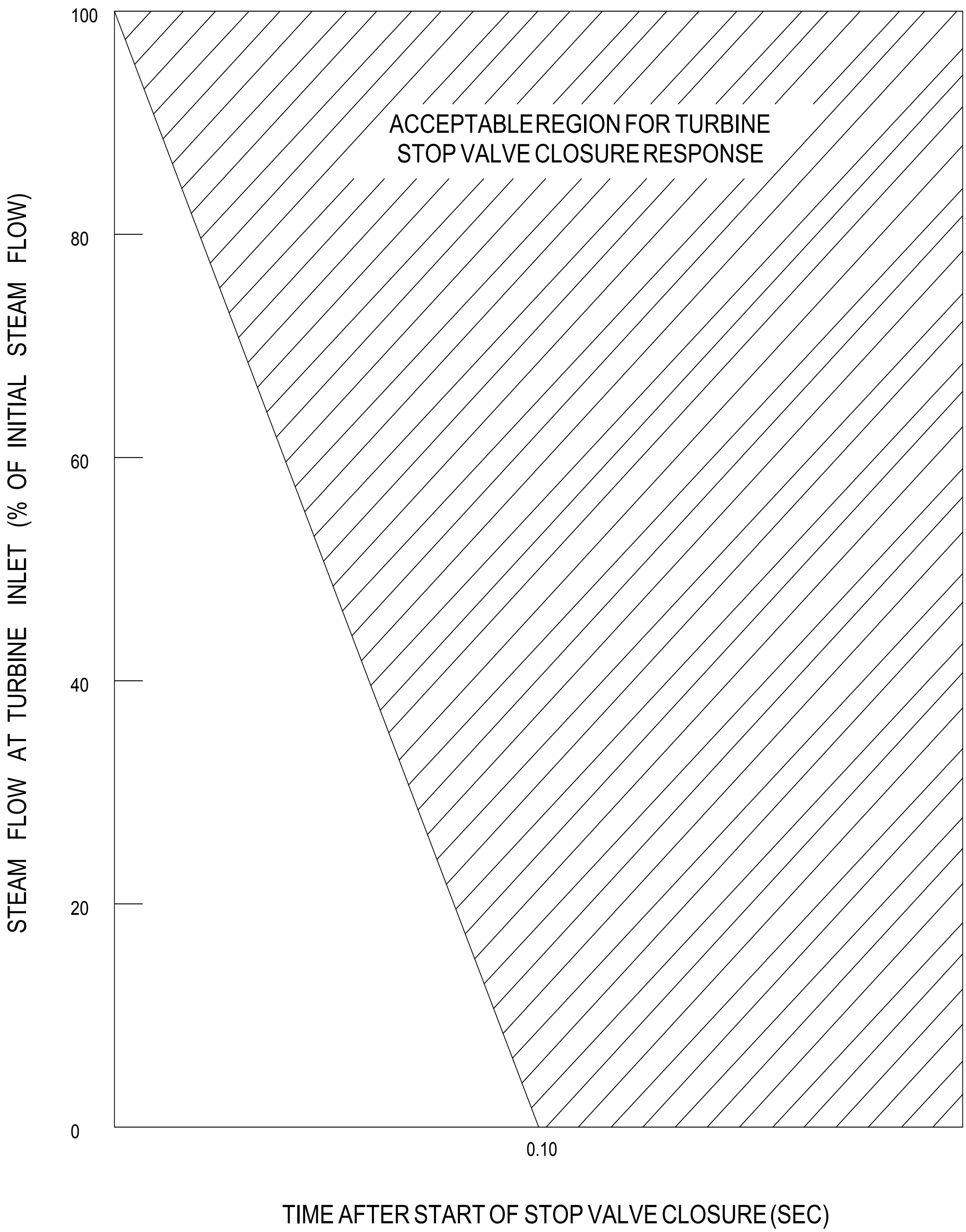


Figure 10.2-1. Turbine Stop Valve Closure Characteristic

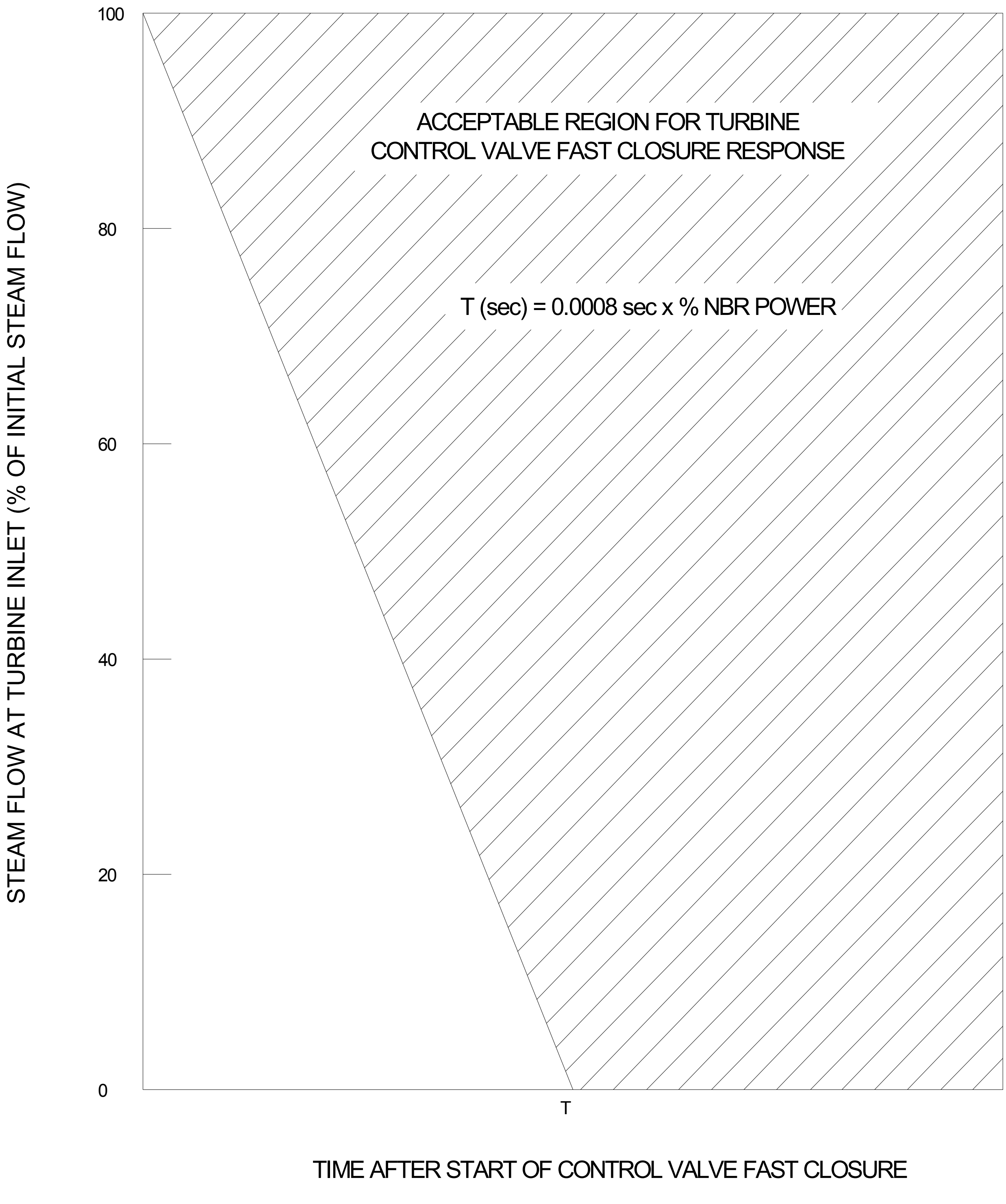
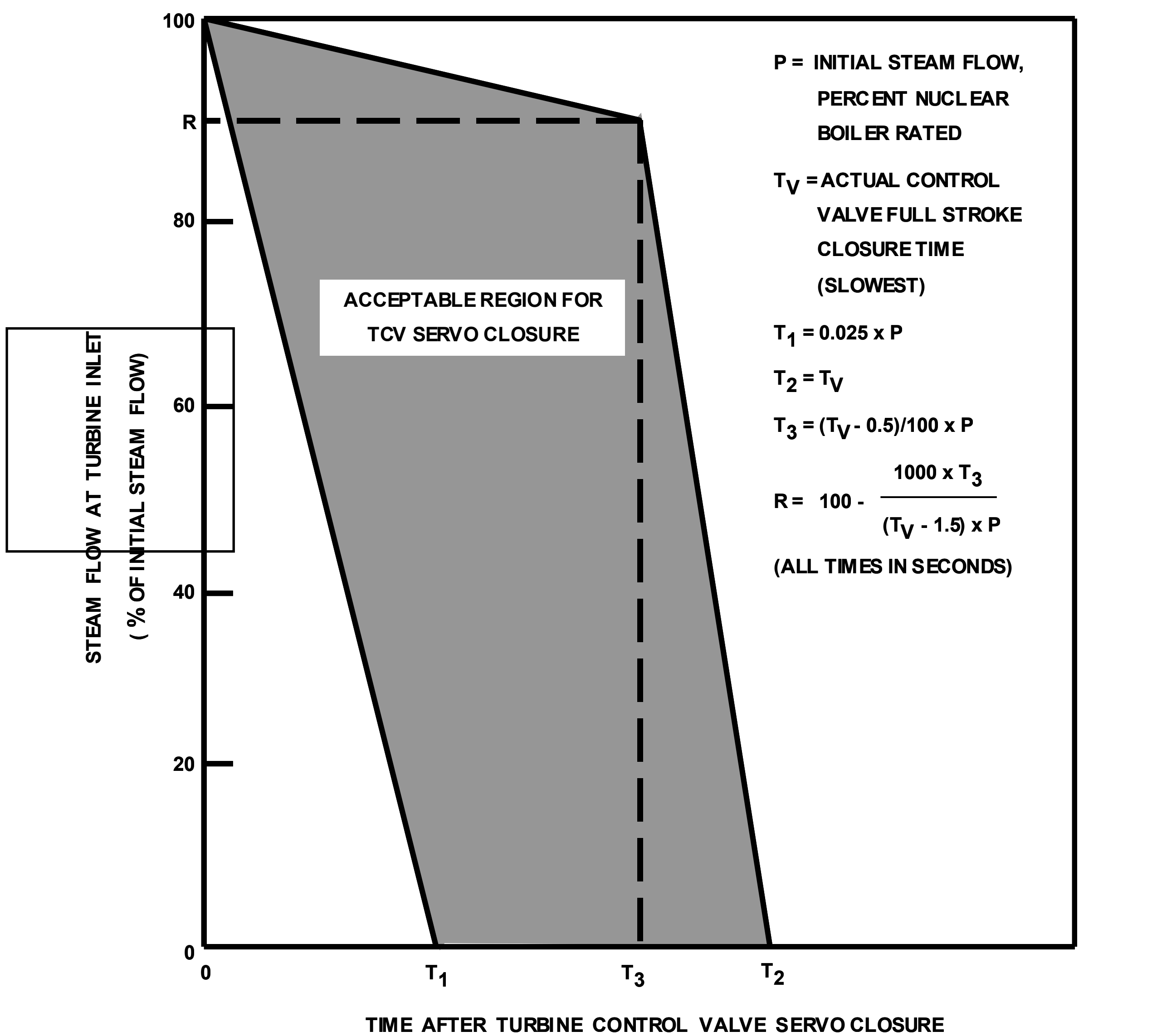


Figure 10.2-2. Turbine Control Valve Fast Closure Characteristic


100
R
80
60
40
20
0
STEAM FLOW AT TURBINE INLET
(% OF INITIAL STEAM FLOW)
ACCEPTABLE REGION FOR
TCV SERVO CLOSURE
P = INITIAL STEAM FLOW, PERCENT NUCLEAR BOILER RATED
T_V = ACTUAL CONTROL VALVE FULL STROKE CLOSURE TIME (SLOWEST)
T_1 = 0.025 x P
$T_2 = T_V$
$T_3 = (T_V - 0.5)/100 \times P$
$R = 100 - \frac{1000 \times T_3}{(T_V - 1.5) \times P}$
(ALL TIMES IN SECONDS)
0
T_1
T_3
T_2
TIME AFTER TURBINE CONTROL VALVE SERVO CLOSURE

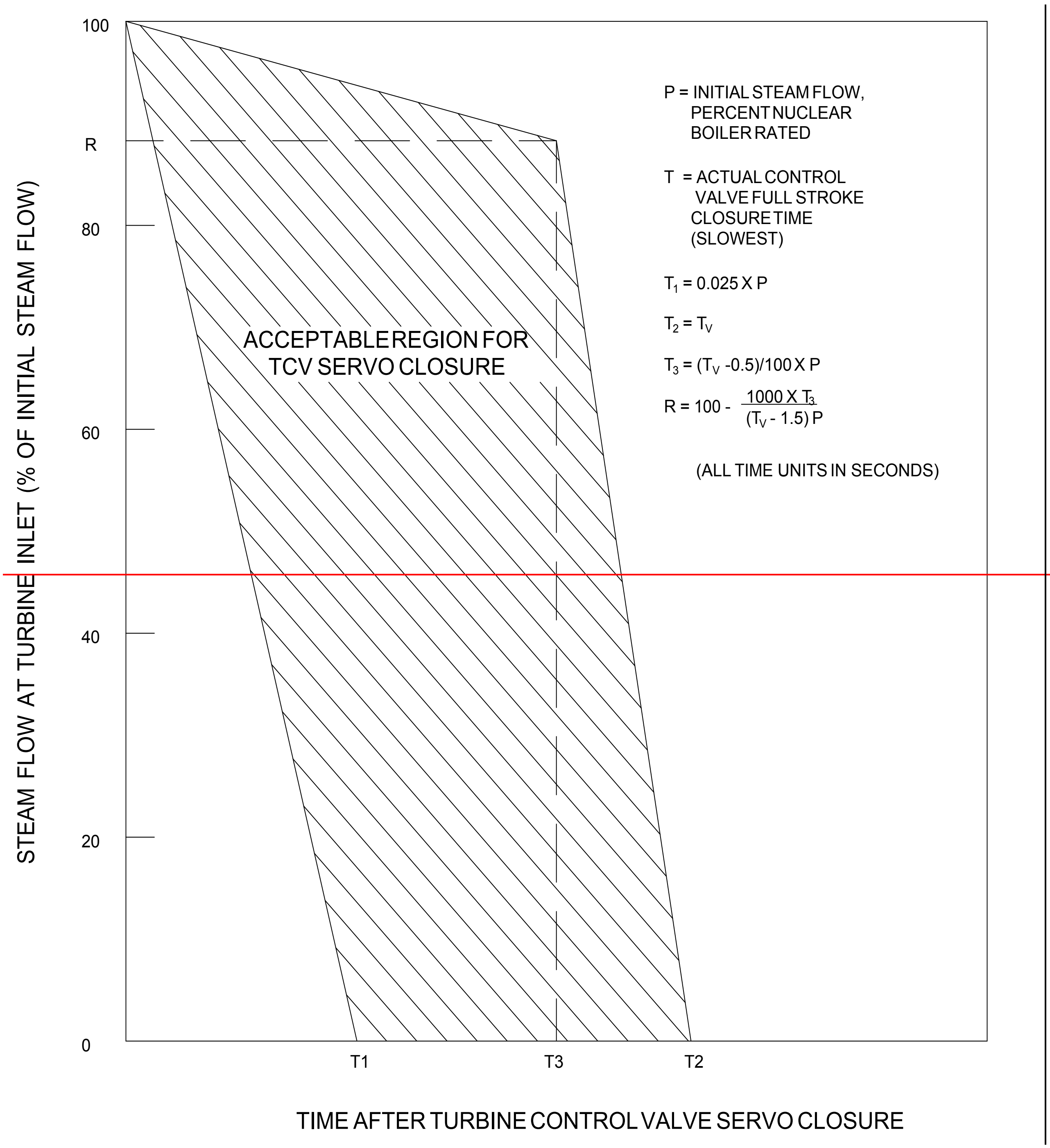


Figure 10.2-3. Acceptable Range for Control Valve Normal Closure Motion

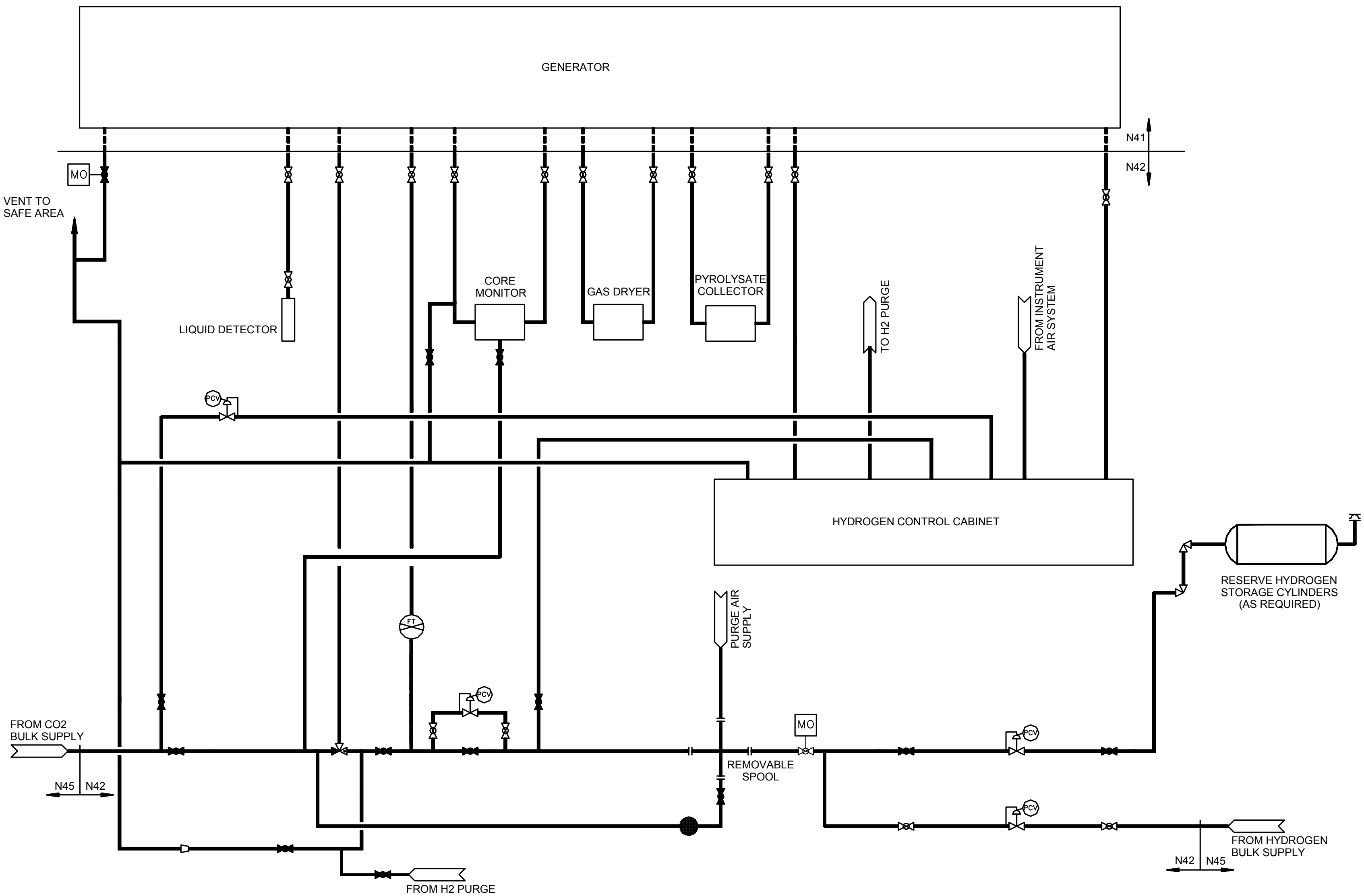


Figure 10.2-4. Hydrogen Gas Control System

Erosion-Corrosion

Piping systems, ASME Section III Code Class 1, 2, 3 and nonsafety-related piping and components as described in NRC Generic Letter 89-08, determined to be susceptible to erosion-corrosion are subject to a program of nondestructive examinations to verify system structural integrity. The examination schedule and examination methods are determined in accordance with the Electric Power Research Institute (EPRI) guidelines in NSAC-202L-R2, which satisfies NRC Generic Letter 89-08, or the latest revision approved by NRC (or equally effective program), and applicable rules of ASME Section XI.

Maintenance and Inspection Program

Equipment requiring special maintenance and inspections shall also be part of the augmented inservice inspection program. For example, equipment important to turbine overspeed protection and referred to in COL Information item 10.2-1-A, should be included.

6.6.8 Code Exemptions

As provided in ASME BPVC Section XI, IWC-1220 and IWD-1220, certain portions of Class 2 and 3 systems are exempt from the volumetric, surface and visual examination requirements of IWC-2500 and IWD-2500.

6.6.9 Code Cases

ASME Section XI requirements can be modified by invoking approved ASME Section XI Code Cases. Approved Code Cases for inservice inspection are listed in RG 1.147. As applicable, the provisions of the Code Cases listed in Table 5.2-1 may be used for preservice and inservice inspections, pressure tests, evaluations, and repair and replacement activities.

6.6.10 Plant Specific PSI/ISI Program Information

6.6.10.1 Relief Requests

The specific areas where the applicable ASME Code requirements cannot be met are identified after the examinations are performed. Should relief requests be required, they are developed through the regulatory process and submitted to the NRC for approval in accordance with 10 CFR 50.55a(g)(5). The relief requests include appropriate justifications and proposed alternative inspection methods.

6.6.10.2 Code Edition

The ASME BPVC Section XI edition and addenda for this program description are as specified in Table 1.9-22. The COL Holder will define the applicable edition and addenda of the ASME Code in the plant specific ISI program.

6.6.11 COL Information

6.6-1-A PSI/ISI Program Description

The COL Applicant is responsible for providing a full description of the PSI/ISI programs and augmented inspection programs for Class 2 and 3 components and piping by supplementing, as necessary, the information in Section 6.6. The augmented inservice inspection program shall also cover erosion-corrosion and equipment requiring special maintenance and inspections as described in 6.6.7. The COL Applicant will also provide milestones for program implementation (Section 6.6).

6.6-2-A PSI/ISI NDE Accessibility Plan Description

The COL Applicant is responsible for developing a plan and providing a full description of its use during construction, PSI, ISI, and for design activities for components that are not included in the referenced certified design, to preserve accessibility to piping systems, to enable NDE of ASME Code Class 2 austenitic and DM welds during ISI (Section 6.6).

6.6.12 References

None.

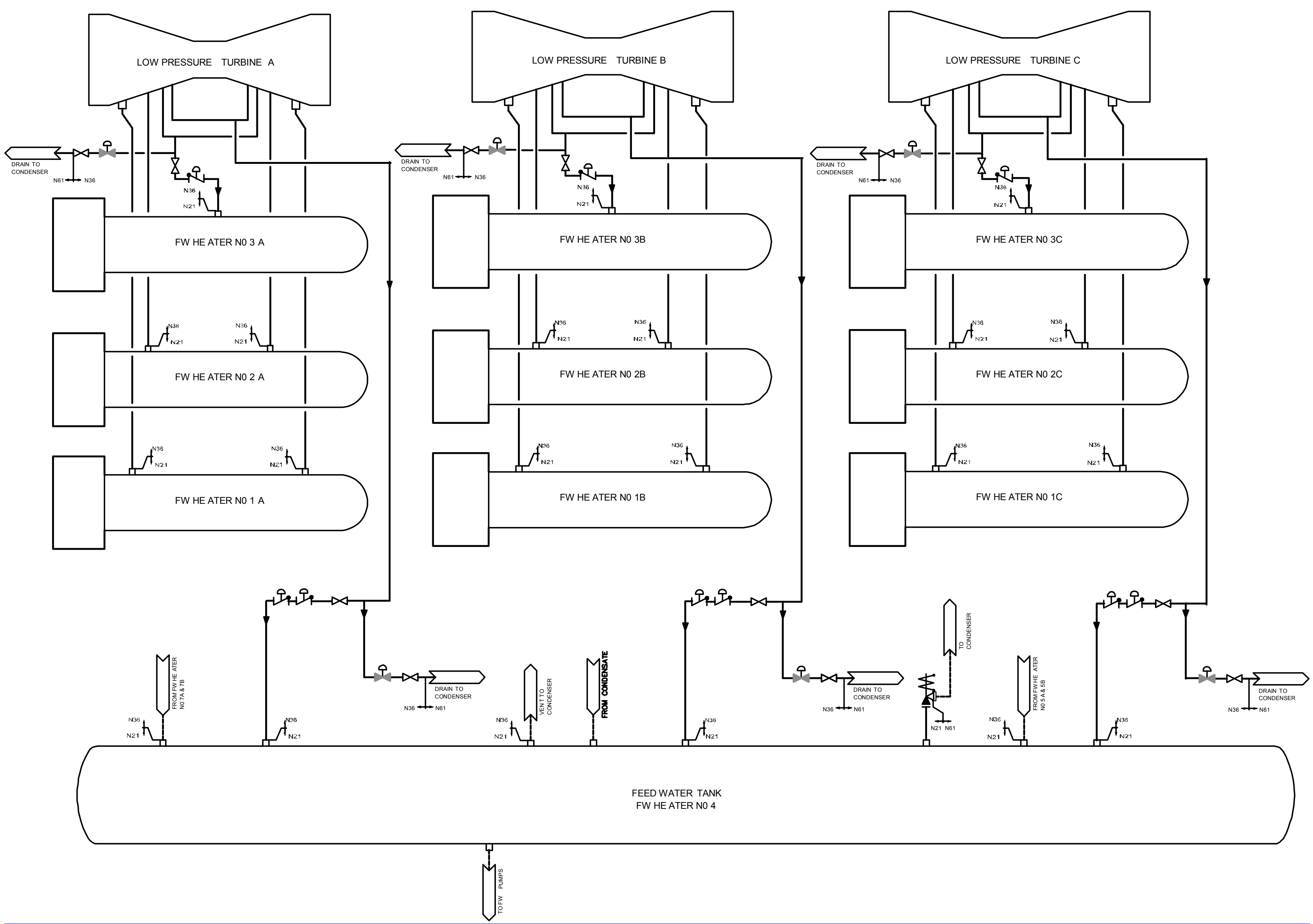
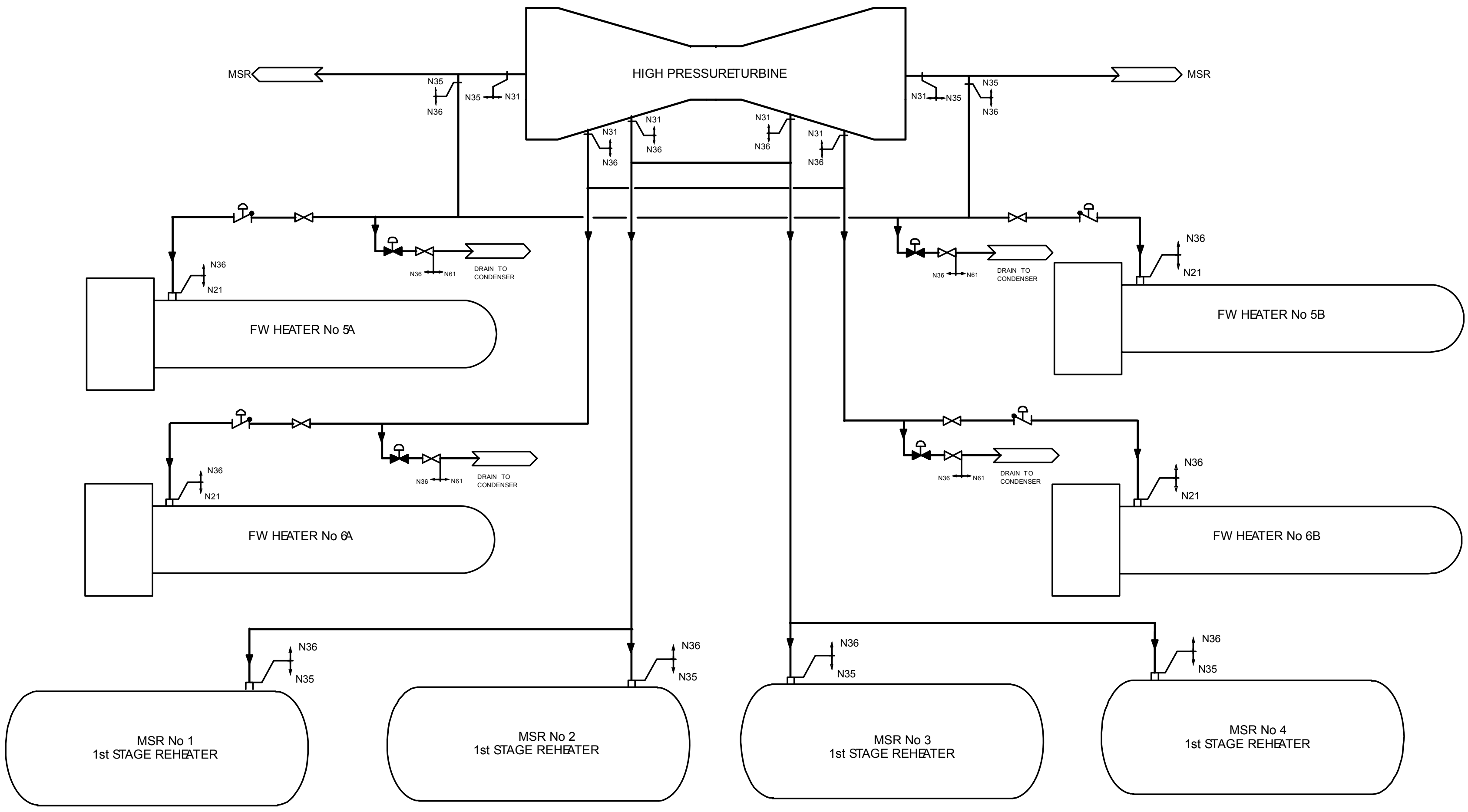

LOW PRESSURE TURBINE A
LOW PRESSURE TURBINE B
LOW PRESSURE TURBINE C
DRAIN TO CONDENSER
FW HEATER N0 3 A
FW HEATER N0 2 A
FW HEATER N0 1 A
FW HEATER N0 3B
FW HEATER N0 2B
FW HEATER N0 1B
FW HEATER N0 3C
FW HEATER N0 2C
FW HEATER N0 1C
FROM FW HEATER N0 7A & 7B
VENT TO CONDENSER
FROM CONDENSATE
TO CONDENSER
FROM FW HEATER N0 5 A & 5B
FEED WATER TANK
FW HEATER N0 4
TO FW PUMPS
N36
N21
N61

Figure 10.4-6a. Low Pressure Extraction Steam System


HIGH PRESSURETURBINE
MSR
MSR
N35
N36
N31
DRAIN TO CONDENSER
N61
N21
FW HEATER No 5A
FW HEATER No 5B
FW HEATER No 6A
FW HEATER No 6B
MSR No 1
1st STAGE REHEATER
MSR No 2
1st STAGE REHEATER
MSR No 3
1st STAGE REHEATER
MSR No 4
1st STAGE REHEATER

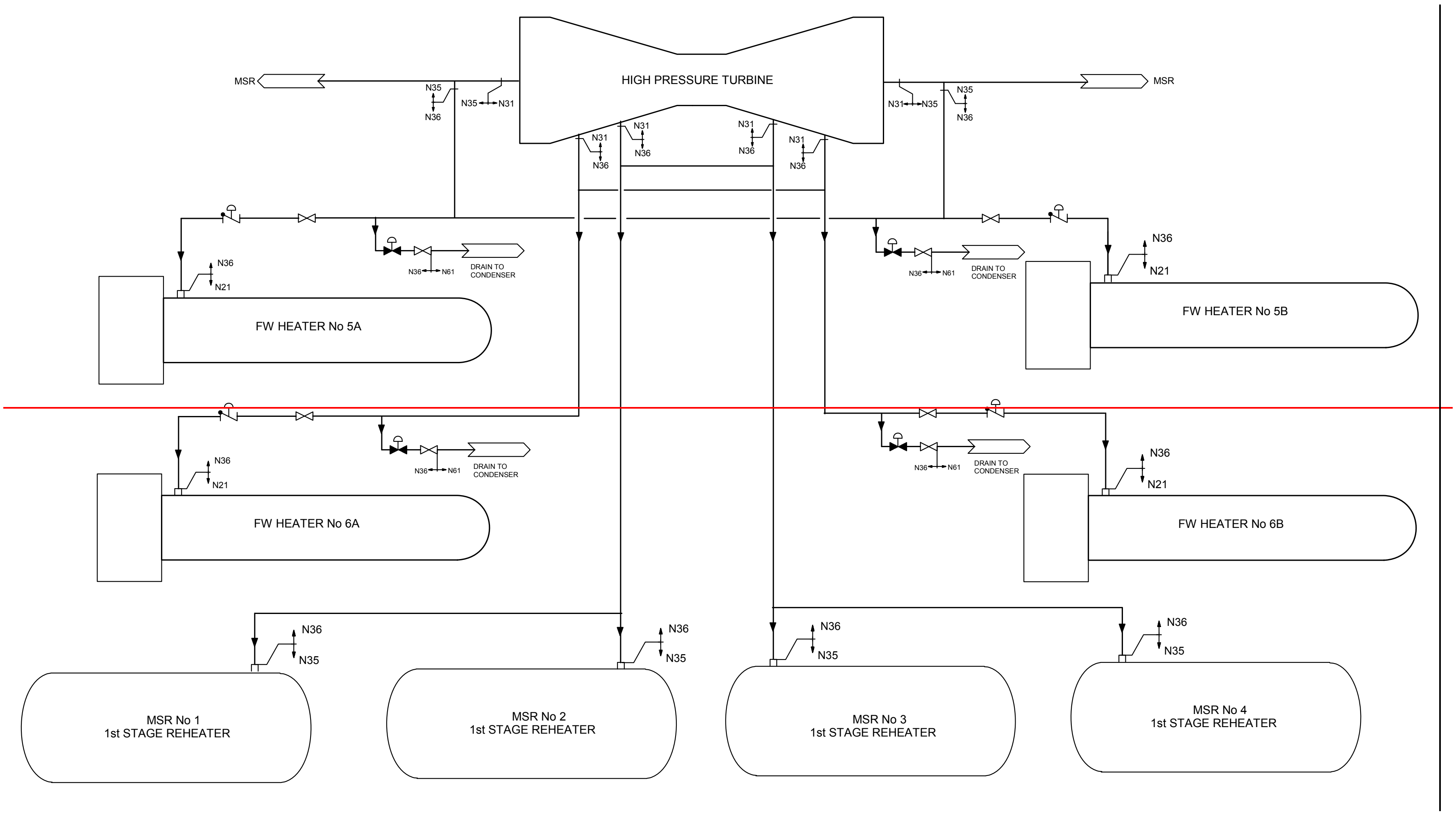


Figure 10.4-7a. High Pressure Extraction Steam System

Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure and approved the initiation of testing. For each scheduled testing iteration, the plant shall be in the appropriate operational configuration with the specified prerequisite testing complete. Applicable instrumentation shall be checked or calibrated as is appropriate

Description

Power ascension phase testing of plant cooling water systems is necessary only to the extent that fully loaded conditions could not be approached during the preoperational phase. Pertinent parameters shall be monitored in order to provide a verification of proper system flow balancing and heat exchanger performance under near design or special conditions, as appropriate. This includes extrapolation of results obtained under normal or test conditions as needed to demonstrate required performance at limiting or accident conditions.

Criteria

System performance shall be consistent with design requirements.

14.2.8.2.19 Heating, Ventilation and Air Conditioning System Performance Test

Purpose

The objective of this test is to verify the ability of various HVAC systems to maintain area temperatures and humidity within the specified limits during reactor power operation.

Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure(s) and approved the initiation of testing. For each scheduled testing iteration, the plant shall be in the appropriate operational configuration with the specified prerequisite testing complete. Applicable instrumentation shall be checked or calibrated as is appropriate.

Description

Power ascension phase testing of plant HVAC systems is necessary only to the extent that fully loaded conditions could not be approached during the preoperational phase. Pertinent parameters are to be monitored in order to provide a final verification of proper system flow balancing and cooler performance under near design or special situation conditions, as appropriate.

Criteria

System performance shall be consistent with design requirements. For systems that are taken credit for in the plant safety analysis, performance shall meet the minimum requirements assumed in such analysis.

14.2.8.2.20 Turbine Valve Performance Test

Purpose

The objective of this test is to demonstrate proper functioning of the ~~main~~ turbine ~~control, stop, and bypass~~ valves during reactor power operation.

Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure(s) and approved the initiation of testing. For each scheduled testing iteration, the plant shall be in the appropriate operational configuration with the specified prerequisite testing complete. Applicable instrumentation shall be checked or calibrated as is appropriate.

Description

Early in the startup test phase with the reactor at a moderate power level and with the turbine generator on-line, the operability of the control, stop, ~~and~~ bypass, non-return, intermediate stop and intercept valves are demonstrated. This testing is similar to the individual valve testing required by the TS surveillances for the bypass valves or the augmented valve testing for the control, stop, non-return, intermediate stop and intercept valves. In addition to valve operability, the overall control system and plant response is observed. Because turbine valve testing is required routinely during power operation, the maximum power level at which such tests can safely be performed is determined by observing plant response during such tests at successively higher power levels.

Criteria

Turbine valves shall operate properly and in accordance with applicable ~~TS~~ requirements. Valve performance, control system response and plant response shall be consistent with design requirements. During high power testing, adequate scram avoidance margins shall be maintained.

14.2.8.2.21 Nuclear Boiler System Isolation Test

Purpose

The objectives of this test are to demonstrate proper operation of and to verify closure times for MSIVs, FW isolation valves, including steamline drain branch isolation valves, during power operation.

Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure(s) and approved the initiation of testing. For each scheduled testing iteration, the plant shall be in the appropriate operational configuration with the specified prerequisite testing complete. Applicable instrumentation shall be checked or calibrated as is appropriate.

Description

Beginning at rated temperature and pressure, and then again at intermediate power levels, each MSIV is individually stroked in the fast closure mode. Valve operability and closure time are verified and overall plant response observed. Closure times are evaluated consistent with TS and safety analysis requirements. If appropriate, the maximum power level at which such tests can safely be performed is determined by observing plant response during such tests at successively higher power levels. In addition, at rated temperature and pressure, proper functioning and stroke timing of steamline drain isolation valves (for example, on the common drain line) are demonstrated.

14.2.8.2.26 Loss of Turbine Generator and Offsite Power Test

Purpose

The objective of this test is to verify proper electrical equipment response and reactor system transient performance during and subsequent to a turbine generator trip with coincident loss of all offsite power sources.

Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure and approved the initiation of testing. The plant shall be in the appropriate operational configuration with specified prerequisite testing complete. Applicable instrumentation shall be checked or calibrated, as appropriate. A sufficient number of qualified personnel shall be available to handle the needs of this test, as well as those associated with normal plant operation.

Description

This test is performed at a relatively low power level early in the power ascension phase, but with the generator on-line at greater than 10% load. The test is initiated in a way such that the turbine generator is tripped and the plant is completely disconnected from all offsite power sources. The plant is maintained isolated from offsite power for a minimum of 30 minutes. During this time, appropriate parameters are monitored in order to verify the proper response of plant systems and equipment, including the proper switching of electrical equipment and the proper starting and sequencing of onsite power sources and their respective loads.

Criteria

Reactor protection system actions shall prevent violation of fuel thermal limits. The ICS and associated plant systems shall function properly without manual assistance to maintain reactor level above the initiation level of ADS and GDCS. The SDGs will start automatically following the loss of both Normal Preferred Power and Alternate Preferred Power and supply power to the 6.9 kV PIP buses. Other systems and equipment shall perform consistent with applicable design and testing specifications.

14.2.8.2.27 Turbine Trip and Generator Load Rejection Test

Purpose

The objective of this test is to verify that the dynamic response of the reactor and applicable systems and equipment is in accordance with design for protective trips of the turbine and generator during power operation.

Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure and approved the initiation of testing. The plant shall be in the appropriate operational configuration with specified prerequisite testing complete. Applicable instrumentation shall be checked or calibrated, as appropriate, including steamline expansion/vibration sensors.

Description

In the ESBWR design, there is no direct scram because of turbine trip or generator load rejection. From an initial power level of 100%, the main generator is tripped (generator output breaker is opened for the turbine trip test and the switchyard breaker is opened for the generator load rejection test) in order to verify the proper reactor and integrated plant response. This method for initiating the trip is chosen to create a complete loss of electrical load so the turbine is subjected to maximum overspeed potential. Reactor parameters such as vessel dome pressure and simulated fuel surface heat flux are monitored and compared with predictions so that the adequacy and conservatism of the analytical models and assumptions used to license the plant can be verified. Proper response of systems and equipment such as the turbine stop, control, and bypass valves, steamline vibration, the RPS, reduction in reactor power by SCRRI and staggered SRI group insertions, and the feedwater system are also demonstrated. The ability of the feedwater system to control vessel level after a 100% load rejection shall also be verified. Overspeed response of the main turbine shall also be evaluated because the generator is unloaded prior to complete shutoff of steam to the turbine.

For a turbine trip, the generator initially remains synchronized and there is no overspeed. However, the dynamic response of the reactor may be different if the steam shutoff rate is different. If there is expected to be a significant difference, it may be necessary to perform a separate demonstration and evaluation (similar to that discussed above), but initiated by a direct trip of the main turbine.

A turbine or generator trip is also to be performed at a lower power level. Reactor dynamic response is not as important for this AOO, compared to the full power demonstration, except for the ability to remain operating as designed. More important is the demonstration of proper integrated plant and system performance.

Criteria

For high power turbine or generator trips, reactor dynamic response shall be consistent with predictions based on expected system characteristics and shall be conservative relative to analysis results based on design assumptions. Feedwater control shall prevent flooding of the steamline following generator or turbine trip. After generator load rejection, turbine speed shall not exceed design limits. The positive change in reactor dome pressure and fuel surface heat flux shall not exceed limits assumed in the transient analysis. ~~Other plant systems and equipment shall perform in accordance with the appropriate design and testing specifications~~ Plant systems and equipment, including the turbine overspeed protection system and associated components, shall perform in accordance with the appropriate design and testing specifications.

14.2.8.2.28 Reactor Full Isolation Test

Purpose

The objective of this test is to verify that the dynamic response of the reactor and applicable systems and equipment is in accordance with design for a simultaneous full closure of all MSIVs from near rated reactor power.

Prerequisites

The preoperational tests are complete and plant management has reviewed the test procedure and approved the initiation of testing. The plant shall be in the appropriate operational configuration with specified prerequisite testing complete. Applicable instrumentation shall be checked or calibrated, as appropriate.

2.11 POWER CYCLE

The following subsections describe the major power cycle (i.e., generation) systems for the ESBWR.

2.11.1 Turbine Main Steam System

Design Description

The Turbine Main Steam System (TMSS) supplies steam generated in the reactor to the Turbine Generator, moisture separator reheaters, steam auxiliaries and turbine bypass system. The TMSS does not include the seismic interface restraint, main turbine stop valves or bypass valves.

The TMSS consists of four lines from the seismic interface restraint to the main turbine stop valves. The TMSS is nonsafety-related. Regulatory Guide 1.26 Quality Group B portions of the TMSS are designed in accordance with ASME Boiler and Pressure Vessel Code, Section III, Class 2 requirements. The TMSS is located in the Reactor Building steam tunnel and Turbine Building.

The Regulatory Guide 1.26 Quality Group B portions of the TMSS are those portions of the Main Steam Lines that extend from the seismic interface restraint (or seismic guide) to the turbine stop valves (non-inclusive), turbine bypass valves (non-inclusive) and the connecting branch lines (nominal 6.35 cm. (2.5 in) and larger) up to and including the first isolation valve which is either normally closed or capable of automatic closure during all modes of normal reactor operation. This defines the portions of the TMSS subject to ASME Code Section III Class 2 requirements. Figures 2.11.1-1 through 2.11.1-3 shows the functional arrangement and class changes to identify the scope equipment within the TMSS.

(1) The TMSS functional arrangement is as described in Subsection 2.11.1 and as shown on Figures 2.11.1-1 through 2.11.1-3.

(2) a1. The ASME Code Section III components of the TMSS are designed in accordance with ASME Code Section III requirements.

a2. The ASME Code Section III components of the TMSS shall be reconciled with the design requirements.

a3. The ASME Code Section III components of the TMSS are fabricated, installed, and inspected in accordance with ASME Code Section III requirements.

b1. The ASME Code Section III components ~~identified in Table 2.11.1-1~~ of the TMSS retain their pressure boundary integrity at their design pressure.

b2. The ASME Code Section III piping of the TMSS retains its pressure boundary integrity at its design pressure.

(3) Upon receipt of an MSIV closure signal, the Steam Auxiliary Isolation Valve(s) close(s) and required MSIV fission product leakage path TMSS drain valve(s) open(s).

(4) The Steam Auxiliary Isolation Valve(s) fail(s) closed and required MSIV fission product leakage path TMSS drain valve(s) fail(s) open on loss of electrical power to the valve actuating solenoid or on loss of pneumatic pressure.

(5) TMSS piping, which consists of the piping (including supports) for the MSL from the seismic interface restraint (or seismic guide) to the turbine stop valves (non-inclusive), turbine bypass valves (non-inclusive) and the connecting branch lines (nominal 6.35 cm. (2.5 in.) and larger up to and including the first isolation valve which is either normally closed or capable of automatic closure during all modes of normal reactor operation, is classified as Seismic Category II.

(6) The integrity of the as-built MSIV leakage path to the condenser (main steam piping, bypass piping, required drain piping, and main condenser as shown on Figure 2.11.1-1) is not compromised by non-seismically designed systems, structures and components.

(7) The non-seismic portion of the MSIV leakage path to the condenser (main steam piping from the stop valve (inclusive) to turbine nozzle, bypass piping, required drain piping, and main condenser) maintains structural integrity under SSE loading conditions.

(8) The TMSS piping is sized to ensure that reactor pressure vessel (RPV) dome to turbine stop valve pressure drop, total main steam system volume, and steamline length are consistent with assumptions in AOO analyses.

(9) a. The TMSS piping portion designated as ASME Code Section III is designed in accordance with ASME Code Section III requirements and Seismic Category II requirements.

b. The as-built TMSS piping portion designated as ASME Code Section III shall be reconciled with the piping design requirements.

c. The TMSS piping portion designated as ASME Code Section III is fabricated, installed, and inspected in accordance with ASME Code Section III requirements..

(10) a. Pressure boundary welds in the ASME Code Section III components of TMSS meet ASME Code Section III non-destructive examination requirements.

b. Pressure boundary welds in the ASME Code Section III piping of the TMSS meet the ASME Code Section III non-destructive examination requirements.

(11) a. Valves on lines attached to the RPV that require maintenance have maintenance valves installed such that freeze seals will not be required.

b. The as-built location of valves on lines attached to the RPV in the TMSS that require maintenance shall be reconciled to design requirements.

(12) The non-return valves shown on functional arrangement Figure 2.11.1-2 and 2.11.1-3 are spring assisted to close.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.11.1-1 provides a definition of the inspections, tests, and analyses, together with associated acceptance criteria for the TMSS.

Table 2.11.1-1

ITAAC For The Turbine Main Steam System

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The TMSS functional arrangement is as described in Subsection 2.11.1 and as shown on Figures 2.11.1-1 through 2.11.1-3.	Inspections of the as-built system will be conducted.	The as-built TMSS conforms to the functional arrangement description in Subsection 2.11.1 and as shown on Figures 2.11.1-1 through 2.11.1-3.
2a1. The ASME Code Section III components of the TMSS are designed in accordance with ASME Code Section III requirements.	Inspection of ASME Code Design Reports (NCA-3550) and required documents will be conducted.	ASME Code Design Report(s) (NCA-3550) (certified, when required by ASME Code) exist and conclude that the design of the ASME code components of the TMSS complies with the requirements of the ASME Code Section III.
2a2. The ASME Code Section III components of the TMSS shall be reconciled with the design requirements.	A reconciliation analysis of the components using as-designed and as-built information and ASME Code Design Reports (NCA-3550) will be performed.	ASME Code Design Report(s) (certified, when required by ASME Code) exist and conclude that design reconciliation has been completed in accordance with the ASME Code for as-built reconciliation of the ASME Code Section III components of the TMSS.
2a3. The ASME code components of the TMSS are fabricated, installed, and inspected in accordance with ASME Code Section III requirements.	Inspection of the components will be conducted.	ASME Code Data Report(s) (including N-5 Data reports, where applicable) (certified, when required by ASME code) and inspection reports exist and conclude that the ASME Code Section III components of the TMSS are fabricated, installed, and inspected in accordance with ASME Code Section III requirements.

Table 2.11.1-1

ITAAC For The Turbine Main Steam System

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
2b1. The ASME Code Section III components of the TMSS retain their pressure boundary integrity at their design pressure.	A hydrostatic test will be conducted on those Code components of the TMSS required to be hydrostatically tested by the ASME Code.	ASME Code Data Report(s) exist and conclude that the results of the hydrostatic test of the ASME ode components of the TMSS comply with the requirements of the ASME Code Section III.
2b2. The ASME Code Section III piping of the TMSS retains its pressure boundary integrity at its design pressure.	A hydrostatic test will be conducted on the code piping of the TMSS required to be hydrostatically tested by the ASME Code.	ASME Code Data Report(s) exist and conclude that the results of the hydrostatic test of the ASME Code piping of the TMSS comply with the requirements of the ASME Code Section III.
3. Upon receipt of an MSIV closure signal, the Steam Auxiliary Isolation Valve(s) close(s) and required MSIV fission product leakage path TMSS drain valve(s) open(s).	Tests will be performed on the Steam Auxiliary Isolation Valves(s) and required MSIV fission product leakage path TMSS drain valve(s) using simulated MSIV closure signals.	The Steam Auxiliary Isolation Valve(s) close(s) and required MSIV fission product leakage path TMSS drain valve(s) open(s) following receipt of a simulated MSIV closure signal.
4. The Steam Auxiliary Isolation Valve(s) fail(s) closed and required MSIV fission product leakage path TMSS drain valve(s) fail(s) open on loss of electrical power to the valve actuating solenoid or on loss of pneumatic pressure.	A functional test will be performed on Steam Auxiliary Isolation Valve(s) and required MSIV fission product leakage path TMSS drain valve(s).	The Steam Auxiliary Isolation Valve(s) fail(s) closed and required MSIV fission product leakage path TMSS drain valve(s) fail(s) open on loss of electrical power to the valve actuating solenoid or on loss of pneumatic pressure.

Table 2.11.1-1

ITAAC For The Turbine Main Steam System

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. TMSS piping, which consists of the piping (including supports) for the MSL from the seismic interface restraint (or seismic guide) to the turbine stop valves (non-inclusive), turbine bypass valves (non-inclusive) and the connecting branch lines (nominal 6.35 cm. (2.5 in) and larger) up to and including the first isolation valve which is either normally closed or capable of automatic closure during all modes of normal reactor operation, is classified as Seismic Category II.	An inspection will be performed to verify that a seismic analysis has been completed for the as-built TMSS piping.	The as-built TMSS piping, which consists of the piping (including supports) for the MSL from the seismic interface restraint (or seismic guide) to the turbine stop valves (non-inclusive), turbine bypass valves (non-inclusive) and the connecting branch lines 6.35 cm. (2.5 in.) and larger up to and including the first isolation valve which is either normally closed or capable of automatic closure during all modes of normal reactor operation, meets Seismic Category II requirements.
6. The integrity of the as-built MSIV leakage path to the condenser (main steam piping, bypass piping, required drain piping, and main condensers as shown on Figure 2.11.1-1) is not compromised by non-seismic~~ally designed~~ systems, structures and components.	Inspections and analysis of non-seismic~~ally designed~~ systems, structures and components overhead, adjacent to, and attached to the MSIV leakage path (i.e., the main steam piping, bypass piping, required drain piping and main condenser) will be performed. The as-built non-seismic systems, structures, and components will be reconciled through inspection and analysis with the results of the initial inspection and analysis.	The as-built non-seismic~~ally designed~~ systems, structures and components overhead, adjacent to, and attached to the MSIV leakage path to the condenser will not compromise the integrity of the main steam piping, bypass piping, required drain piping and main condenser.

Table 2.11.1-1

ITAAC For The Turbine Main Steam System

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7. The non-seismic portion of the MSIV leakage path to the condenser (main steam piping from the stop valve (inclusive) to turbine nozzle, bypass piping, required drain piping, and main condenser) maintains structural integrity under SSE loading conditions	An analysis of the as-built non-seismic portion of the MSIV leakage path to the condenser will be performed to verify that it maintains structural integrity under SSE loading conditions.	The as-built non-seismic portion of the MSIV leakage path to the condenser (main steam piping from the stop valve (inclusive) to turbine nozzle, bypass piping, required drain piping, and main condenser) maintains structural integrity under SSE loading conditions.
8. The TMSS piping is sized to ensure that RPV dome to turbine stop valve pressure drop, total main steam system volume, and steamline length are consistent with assumptions in Abnormal Event analyses.	Inspection and analysis of the as-built TMSS piping will be performed to confirm RPV to turbine calculated pressure drop, total main steam system volume, and steamline length are consistent with assumptions in Abnormal Events analyses.	The TMSS piping is sized to be consistent with these Abnormal Events analyses inputs: • Minimum Steamline Pressure Drop from RPV Dome to Turbine Throttle at rated conditions: 0.179 MPa (26 psi) • Minimum Main Steam System Volume: 103.3 m^3 (3648 ft^3) • Minimum Steamline Length: 65.26 m (214.1 ft)

Table 2.11.1-1

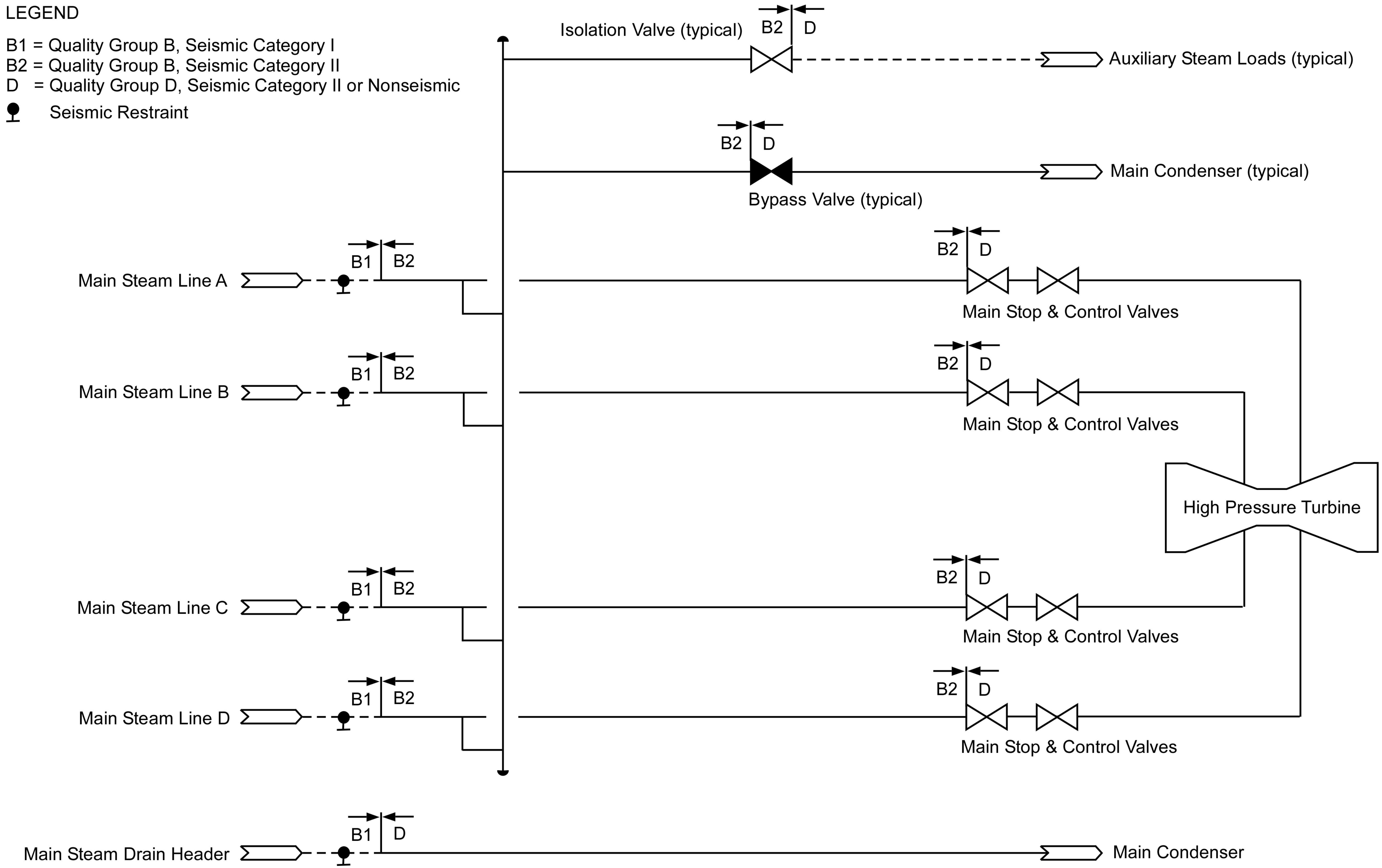
ITAAC For The Turbine Main Steam System

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
9a. The TMSS piping portion designated as ASME Code Section III is designed in accordance with ASME Code Section III requirements and Seismic Category II requirements.	Inspection of ASME code Design Reports (NCA-3550) and required documents will be conducted. {{Design Acceptance Criteria}}	ASME Code Design Report(s) (NCA-3550) (certified, when required by ASME Code) exist and conclude that the design of the TMSS piping portion designated as ASME Code Section III complies with the requirements of the ASME Code, Section III, and meets Seismic Category II requirements. {{Design Acceptance Criteria}}
9b. The as-built TMSS piping portion designated as ASME Code Section III shall be reconciled with the piping design requirements.	A reconciliation analysis of the piping using the as-designed and as-built information and ASME code Design Reports (NCA-3550) will be performed.	ASME Code Design Report(s) (certified, when required by ASME Code) exist and conclude that design reconciliation has been completed in accordance with the ASME code for as-built reconciliation of the TMSS piping portion designated as ASME Code Section III. The report documents the results of the reconciliation analysis.
9c. The TMSS piping portion designated as ASME Code Section III is fabricated, installed, and inspected in accordance with ASME Code Section III requirements.	Inspections of the piping will be conducted.	ASME Code Data Report(s) (certified, when required by ASME code) and inspection reports (including N-5 Data Reports where applicable) exist and conclude that the TMSS piping portion designated as ASME Code Section III is fabricated, installed, and inspected in accordance with ASME Code Section III requirements.

Table 2.11.1-1

ITAAC For The Turbine Main Steam System

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
10a. Pressure boundary welds in the ASME Code Section III components of TMSS meet ASME Code Section III non-destructive examinations requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	ASME Code Report(s) exist and conclude that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds in the TMSS components.
10b. Pressure boundary welds in the ASME Code Section III piping of the TMSS meet the ASME Code Section III non-destructive examinations requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	ASME Code Report(s) exist and conclude that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds in the TMSS piping.
11a. Valves on lines attached to the RPV that require maintenance have maintenance valves installed such that freeze seals will not be required.	Inspections of piping design isometric drawings will be conducted. {{Design Acceptance Criteria}}	A review of piping design isometric drawings confirms that maintenance valves are included such that freeze seals will not be required. {{Design Acceptance Criteria}}
11b. The as-built location of valves on lines attached to the RPV in the TMSS that require maintenance shall be reconciled to design requirements.	A reconciliation evaluation of valves on lines attached to the RPV that require maintenance using as-designed and as-built information will be performed.	A design reconciliation has been completed for the as-built location of valves relative to the design requirements. The report documents the results of the reconciliation evaluation.
12. The non-return valves shown on functional arrangement Figure 2.11.1-2 and 2.11.1-3 are spring assisted to close.	Inspections of the as-built system will be conducted.	The non-return valves shown on functional arrangement Figure 2.11.1-2 and 2.11.1-3 are spring assisted to close.


LEGEND
B1 = Quality Group B, Seismic Category I
B2 = Quality Group B, Seismic Category II
D = Quality Group D, Seismic Category II or Nonseismic
Seismic Restraint
Isolation Valve (typical)
B2
D
Auxiliary Steam Loads (typical)
B2
D
Main Condenser (typical)
Bypass Valve (typical)
Main Steam Line A
B1
B2
B2
D
Main Stop & Control Valves
Main Steam Line B
B1
B2
B2
D
Main Stop & Control Valves
High Pressure Turbine
Main Steam Line C
B1
B2
B2
D
Main Stop & Control Valves
Main Steam Line D
B1
B2
B2
D
Main Stop & Control Valves
Main Steam Drain Header
B1
D
Main Condenser

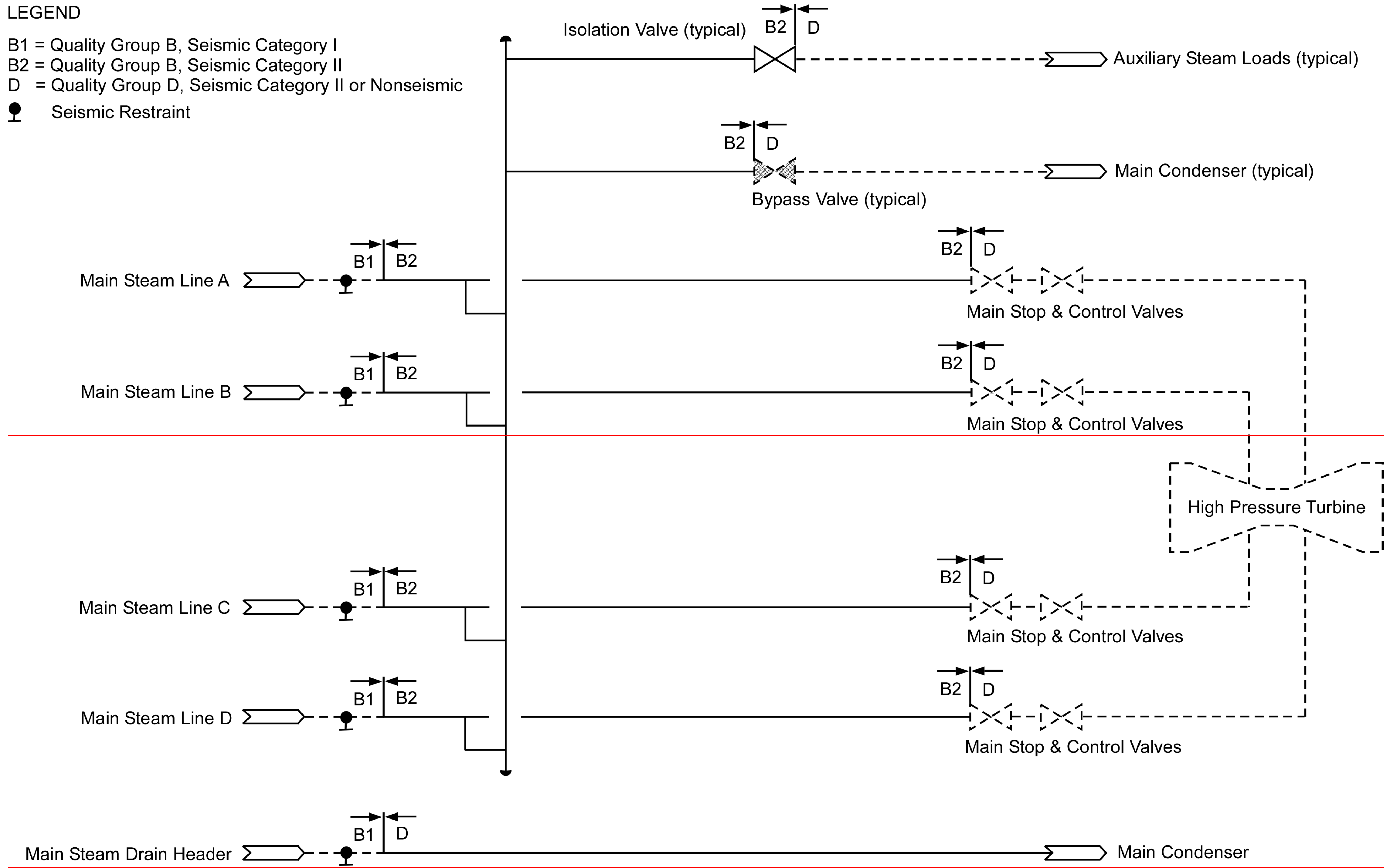


Figure 2.11.1-1. TMSS Functional Arrangement

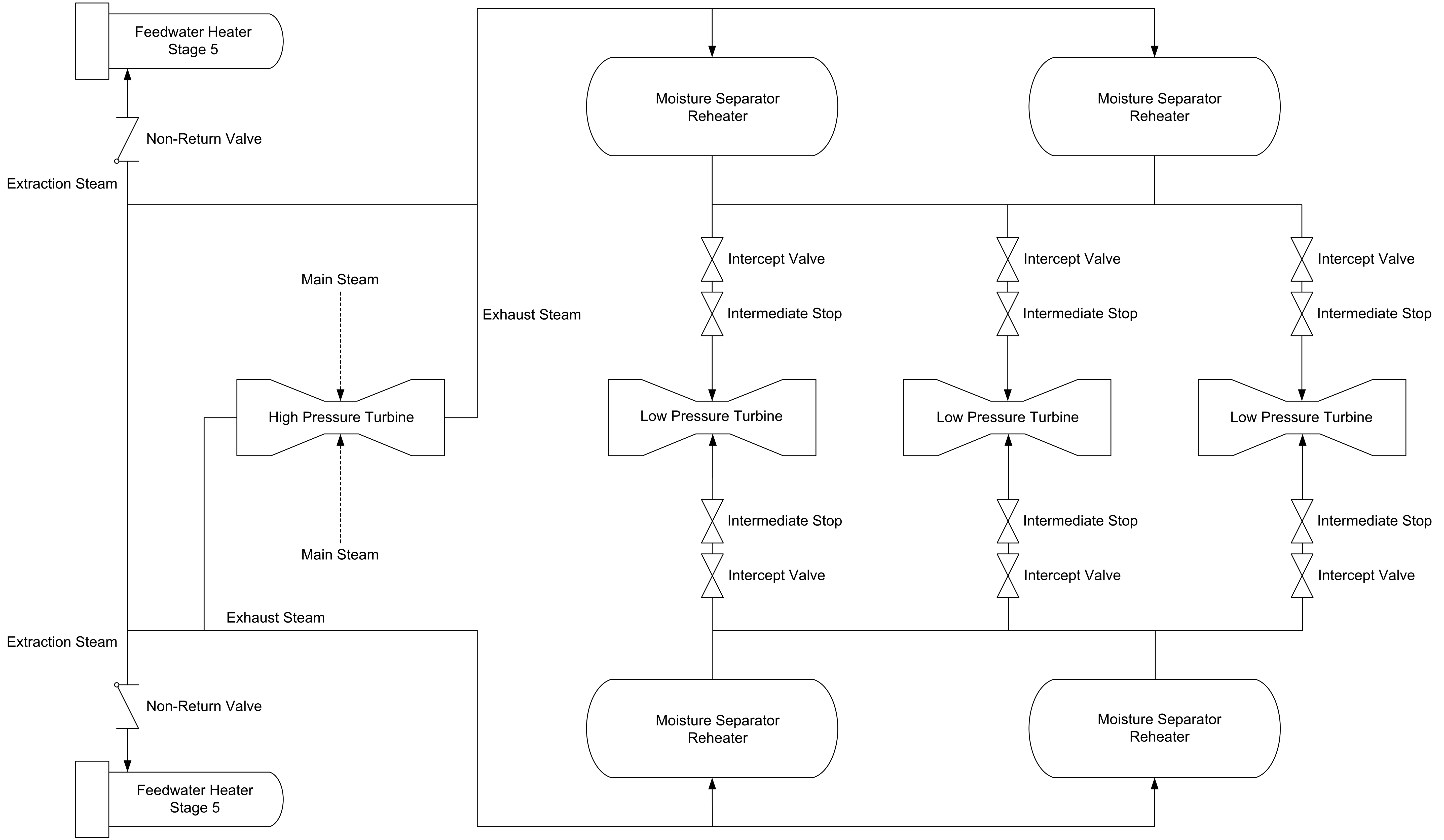


Figure 2.11.1-2. High Pressure Turbine Exhaust Functional Arrangement

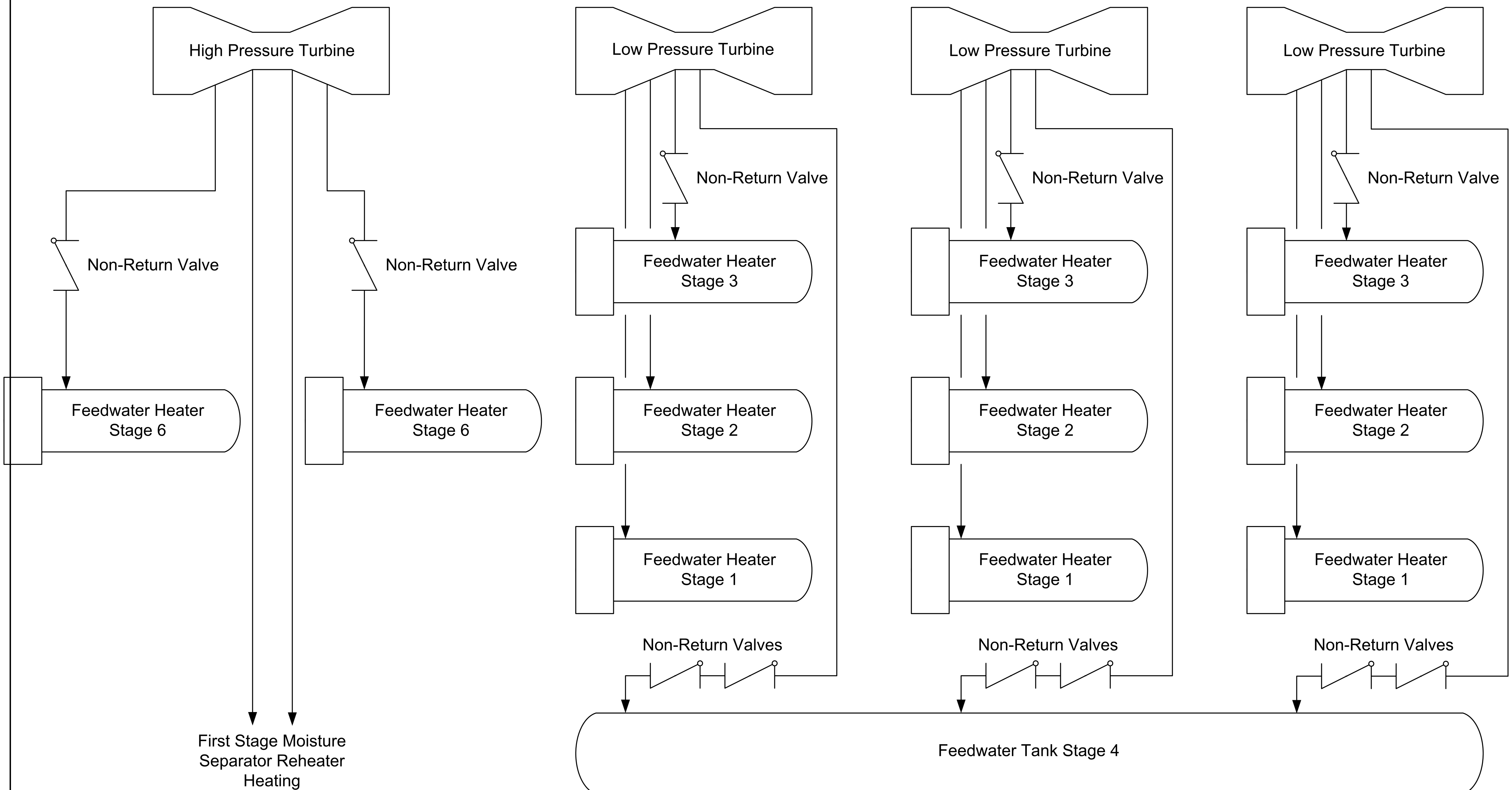


Figure 2.11.1-3. Extraction Steam Functional Arrangement

2.11.2 Condensate and Feedwater System

Design Description

The function of the Condensate and Feedwater System (C&FS) is to receive condensate from the condenser hotwell(s), supply condensate to the Condensate Purification System (CPS), and deliver feedwater to the reactor. The C&FS is classified as nonsafety-related.

Condensate is pumped from the main condenser hotwell(s) by the condensate pumps, passes through the CPS, auxiliary condenser/coolers, low-pressure feedwater heaters and into the feedwater tank. The feedwater booster pumps take suction from the open feedwater tank and provide adequate suction head for the reactor FW pumps, which pump feedwater through the high-pressure feedwater heaters to the reactor. The C&FS boundaries extend from the main condenser outlet to (but not including) the seismic interface restraint outside containment. The C&FS is located in the Reactor Building steam tunnel and Turbine Building.

(1) The functional arrangement for the C&FS is as described in Subsection 2.11.2.

(2) The C&FS provides sufficient feedwater flow and volume to mitigate AOOs.

(3) The C&FS limits maximum feedwater flow to mitigate AOOs.

(4) The C&FS, in conjunction with the feedwater control system, provides sufficient feedwater flow after MSIV isolation to mitigate AOOs.

(5) The C&FS, in conjunction with the feedwater control system, limits the maximum feedwater flow for a single pump following a single active component failure or operator error to mitigate AOOs.

(6) The C&FS, in conjunction with the feedwater control system, is designed so that the loss of feedwater heating is limited in the event of a single operator error or equipment failure.

(7) The C&FS, in conjunction with other Power Cycle Systems, provides a nominal full load final feedwater temperature that is consistent with assumptions in AOOs analyses.

(8) The C&FS has a nominal feedwater flow rate at rated conditions that is consistent with inputs and assumptions in AOOs analyses.

(9) a. Valves on lines attached to the RPV system that require maintenance have maintenance valves such that freeze seals will not be required.

b. The as-built location of valves on lines attached to the RPV system in the C&FS that require maintenance shall be reconciled to design requirements.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.11.2-1 provides a definition of the inspections, tests, and analyses, together with associated acceptance criteria for the Condensate and Feedwater System.

Table 2.11.2-1

ITAAC For The Condensate and Feedwater System

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement for the C&FS is as described in Subsection 2.11.2.	Inspections of the as-built system will be conducted to confirm the functional arrangement.	The as-built C&FS conforms to the functional arrangement described in Subsection 2.11.2.
2. The C&FS provides sufficient feedwater flow and volume to mitigate AOOs.	An analysis of the as-built C&FS and feedwater pumps will be performed to confirm the minimum capacity of three feedwater pumps. The analysis may be supported by type testing.	Three operating feedwater pumps are capable of supplying 135% of the rated feedwater flow at 7.34 MPaG (1065 psig) for mitigating AOOs.
3. The C&FS limits maximum feedwater flow to mitigate AOOs.	Analysis or type testing of the as-built C&FS and feedwater pumps will be performed to confirm that the C&FS limits maximum feedwater flow. The analysis may be supported by type testing.	The maximum capacity of three feedwater pumps at 7.34 MPaG (1065 psig) is less than or equal to 155% of rated feedwater flow for mitigating AOOs.
4. The C&FS, in conjunction with the feedwater control system, provides sufficient feedwater flow after MSIV isolation to mitigate AOOs.	Inspection or analysis of the as-built feedwater system will be performed to confirm that the C&FS provides sufficient feedwater flow after MSIV isolation.	The C&FS, in conjunction with the feedwater control system, provides feedwater flow greater than or equal to 240 seconds of rated feedwater flow after MSIV isolation for mitigating AOOs.
5. The C&FS, in conjunction with the feedwater control system, limits the maximum feedwater flow for a single pump following a single active component failure or operator error to mitigate AOOs.	Testing or analysis of the as-built C&FS and feedwater pumps or type testing of a single feedwater pump will be performed to confirm that the C&FS limits the maximum feedwater flow from a single pump.	The C&FS, in conjunction with the feedwater control system, limits the maximum feedwater flow for a single pump to 75% of rated flow following a single active component failure or operator error for mitigating AOOs.

Table 2.11.2-1

ITAAC For The Condensate and Feedwater System

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6. The C&FS, in conjunction with the feedwater control system, is designed so that the loss of feedwater heating is limited in the event of a single operator error or equipment failure.	Inspection or analysis of the as-built feedwater system will be performed to confirm that the C&FS, in conjunction with the feedwater control system, limits the loss of feedwater heating in the event of a single operator error or equipment failure.	The C&FS, in conjunction with the feedwater control system, is designed so that the loss of feedwater heating is limited to a final feedwater temperature reduction less than or equal to 55.6°C (100°F) in the event of a single operator error or equipment failure.
7. The C&FS, in conjunction with other Power Cycle Systems, provides a nominal full load final feedwater temperature that is consistent with assumptions in AOOs analyses.	Inspection or analysis of the as-built feedwater system and other Power Cycle Systems will be performed to confirm the nominal full load final feedwater temperature.	The C&FS, in conjunction with other Power Cycle Systems, provides a nominal full load final feedwater temperature of 216°C (420°F) as assumed in AOOs.
8. The C&FS has a nominal feedwater flow rate at rated conditions that is consistent with inputs and assumptions in AOOs analyses.	Testing or analysis of the as-built C&FS and feedwater pumps and type testing of a single feedwater pump will be performed to confirm the nominal feedwater flow rate at rated conditions.	The C&FS has a nominal feedwater flow rate at rated conditions of 2.43×10^3 kg/s (19.3×10^6 lbm/hr) as assumed in AOOs.
9a. Valves on lines attached to the RPV system that require maintenance have maintenance valves such that freeze seals will not be required.	Inspections of piping design isometric drawings will be conducted. {{Design Acceptance Criteria}}	A review of piping design isometric drawings confirms that maintenance valves are included such that freeze seals will not be required. {{Design Acceptance Criteria}}

Table 2.11.2-1

ITAAC For The Condensate and Feedwater System

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
9b. The as-built location of valves on lines attached to the RPV system in the C&FS that require maintenance shall be reconciled to design requirements.	A reconciliation evaluation of valves on lines attached to the RPV system that require maintenance using as-designed and as-built information will be performed.	A design reconciliation has been completed for the as-built location of valves relative to the design requirements. The report documents the results of the reconciliation evaluation.

2.11.3 Condensate Purification System

No ITAAC are required for this system.

2.11.4 Main Turbine

Design Description

The Main Turbine is nonsafety-related. The ESBWR standard plant design has a favorably oriented turbine to minimize any potential impact on safety-related structures and equipment.

(1) The physical layout of the Main Turbine system assures that protection is provided to essential systems and components, as required, from the effects of high and moderate energy Main Turbine system piping failures or failure of the connection(s) from the low pressure turbine exhaust hood(s) to the condenser. Essential systems and components are defined in BTP SPLB 3-1 as systems and components required to shut down the reactor and mitigate the consequences of a postulated piping failure, without offsite power. The physical layout also includes protection for the structures, systems, or components (SSCs) listed in Table 2.11.4-1.

(2) The Main Turbine has a favorable orientation to minimize the potential effects of turbine missiles on safety-related structures, systems, or components and the structures, systems, or components listed in Table 2.11.4-1.~~structures, systems, or components (SSCs).~~ The safety-related SSCs that are located within the low-trajectory turbine missile strike zone are failsafe ~~in design~~or protected by barriers.

(3) The Main Turbine control valve closing times are limited to mitigate Abnormal Events.

(4) The Main Turbine stop valve closing times are limited to mitigate Abnormal Events.

(5) The Main Turbine can accommodate sufficient steam flow through three control valves to mitigate Abnormal Events.

(6) The probability of a strike by a turbine missile is sufficiently low to prevent equipment damage to essential systems.

(7) The as-built turbine material properties, turbine rotor and blade designs, pre-service inspection and testing results and in-service testing and inspection requirements meet the requirements defined in the Turbine Missile Probability Analysis.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.11.4-~~1~~ 2 provides a definition of the inspections, tests, and analyses, together with associated acceptance criteria for the Main Turbine.

Table 2.11.4-1

Additional Equipment Protected from Turbine Missiles

FPS Diesel Driven Pump
FPS Motor Driven Pump
FPS to FAPCS Connection
PARs
PCCS Vent Fans
CRHAVS Air Handling Units
Emergency Lighting
FPS Water Tank
FPS Diesel Fuel Oil Tank
Ancillary Diesel Generators
Ancillary AC Power Buses
Ancillary DG Fuel Oil Tank
Ancillary DG Fuel Oil Transfer Pump
Ancillary Diesel Building HVAC
CRHAVS Air Handling Unit auxiliary heaters and coolers

Table 2.11.4-12

ITAAC For The Main Turbine

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The physical layout of the Main Turbine system assures that protection is provided to essential systems and components, as required, from the effects of high and moderate energy Main Turbine system piping failures or failure of the connection(s) from the low pressure turbine exhaust hood(s) to the condenser. Essential systems and components are defined in BTP SPLB 3-1 as systems and components required to shut down the reactor and mitigate the consequences of a postulated piping failure, without offsite power. The physical layout also includes protection for the structures, systems, or components (SSCs) listed in Table 2.11.4-1.	Inspections of the as-built Turbine Building and plant arrangements will be conducted.	The physical layout of the Main Turbine system protects essential systems and components from the effects of high and moderate energy Main Turbine system piping failures or failure of the connection(s) from the low pressure turbine exhaust hood to the condenser. Essential systems and components are defined in BTP SPLB 3-1 and equipment, structures, systems, or components (SSCs) listed in Table 2.11.4-1 as systems and components required to shut down the reactor and mitigate the consequences of a postulated piping failure, without offsite power.

Table 2.11.4-12

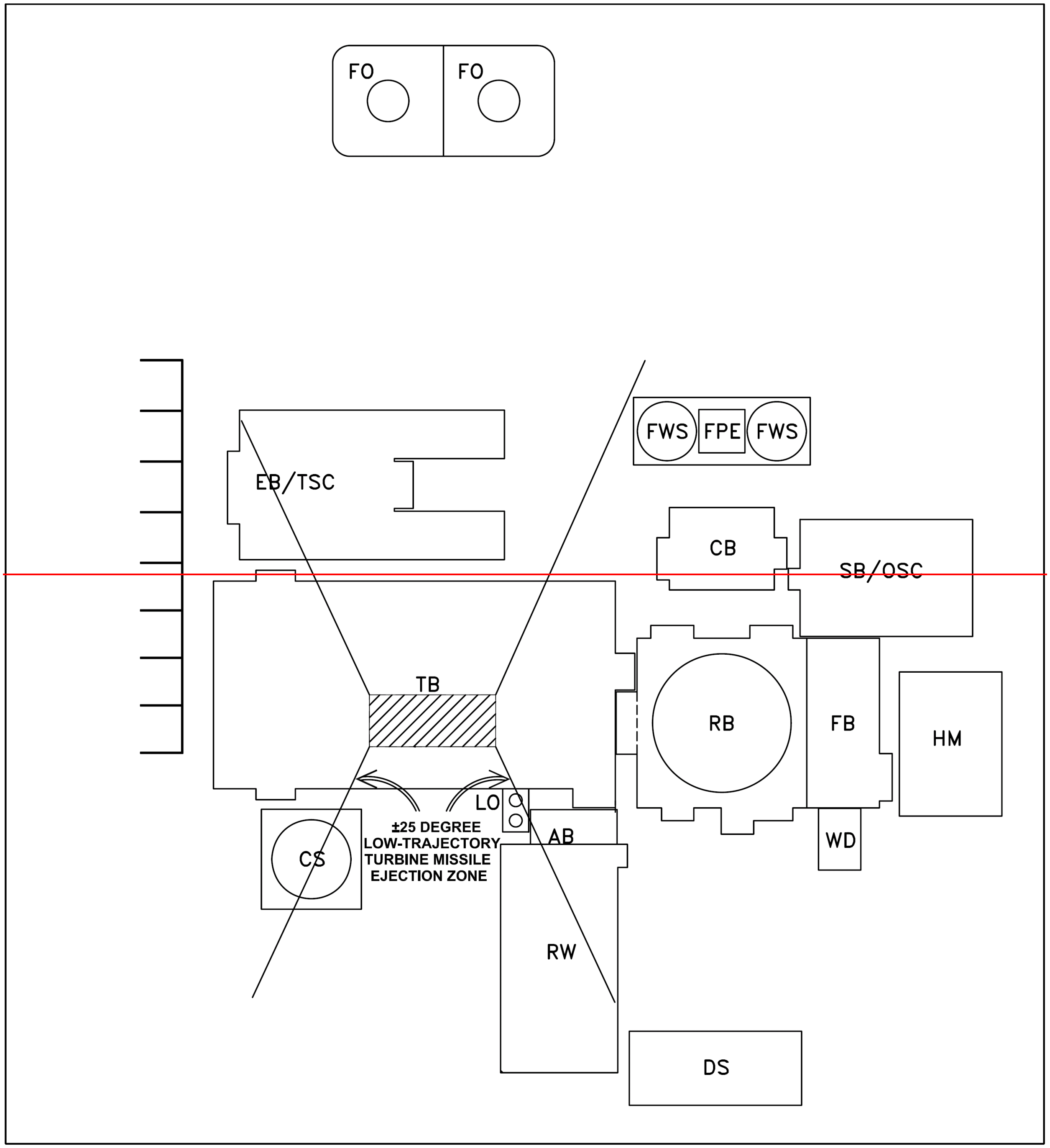
ITAAC For The Main Turbine

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
2. The Main Turbine has a favorable orientation to minimize the potential effects of turbine missiles on safety-related structures, systems, or components (SSCs). and the structures, systems, or components listed in Table 2.11-4-1. The safety-related SSCs that are located within the low-trajectory turbine missile strike zone are failsafe in designor protected by physical barriers.	Inspections of turbine orientation with respect to safety-related SSCs and the SSCs listed in Table 2.11.4-1 will be conducted. The consequences of turbine missile impact on those SSCs that are located within the low-trajectory turbine missile strike zone defined by Figure [reference figure in RG?1 of Regulatory Guide 1.115]will be analyzed. Inspections will be performed to verify the orientation of the Main Turbine, and that any safety-related SSCs within the low-trajectory turbine missile strike zone are failsafe in design. This inspection will also ensure that structures, systems, or components (SSCs) listed in Table 2.11.4-1 are not within the missile strike zone.	An analysis exists thatexists that confirms that any safety-related SSCs and SSCs listed in Table 2.11.4-1 that are located inside the low trajectory turbine missile strike zone are failsafe or are protected by physical barriers. The Main Turbine has a favorable orientation to minimize the potential effects of turbine missiles on safety-related SSCs, and structures, systems, or components (SSCs) listed in Table 2.11.4-1, and that any safety-related SSCs within the low-trajectory turbine missile strike zone are failsafe in design.
3. The Main Turbine control valve closing times are limited to mitigate Abnormal Events.	Testing or analysis of the as-built Main Turbine and type testing of a single turbine control valve will be performed to confirm control valve closing times.	The Main Turbine control valve fast closing time characteristic is limited to a minimum greater than or equal to the equivalent of 0.08 seconds at 100% NBR. The servo closing time is limited to a minimum greater than or equal to 2.5 seconds for mitigating Abnormal Events.

Table 2.11.4-~~1~~2

ITAAC For The Main Turbine

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4. The Main Turbine stop valve closing times are limited to mitigate Abnormal Events.	Testing or analysis of the as-built Main Turbine and type testing of a single turbine stop valve will be performed to confirm stop valve closing time.	The Main Turbine stop valve closing time is limited to a minimum greater than or equal to 0.100 seconds for mitigating Abnormal Events.
5. The Main Turbine can accommodate sufficient steam flow through three control valves to mitigate Abnormal Events.	An inspection of the analysis of the as-built Main Turbine will be performed to confirm that the Main Turbine can accommodate sufficient steam flow through three control valves.	The Main Turbine can accommodate a flow greater than or equal to 85% of rated steam flow through three control valves for mitigating Abnormal Events.
6. The probability of a strike by a turbine missile is sufficiently low to prevent equipment damage to essential systems.	A turbine missile probability analysis will be performed to demonstrate the probability of turbine failure resulting in the ejection of turbine rotor (or internal structure) fragments through the turbine casing is less than the regulatory limiting value.	Turbine Missile Probability Analysis Report(s) exist and conclude that the probability of turbine failure resulting in the ejection of turbine rotor (or internal structure) fragments through the turbine casing is less than $1x10^{-4}$ per year.
7. The as-built turbine material properties, turbine rotor and blade designs, pre-service inspection and testing results and in-service testing and inspection requirements meet the requirements defined in the Turbine Missile Probability Analysis.	An inspection of the as-built turbine material properties, turbine rotor and blade designs, pre-service inspection and testing results, and in-service testing and inspection requirements will be conducted.	The as-built turbine material properties, turbine rotor and blade designs, pre-service inspection and testing results and in-service inspection and testing requirements meet the requirements of the Turbine Missile Probability Analysis.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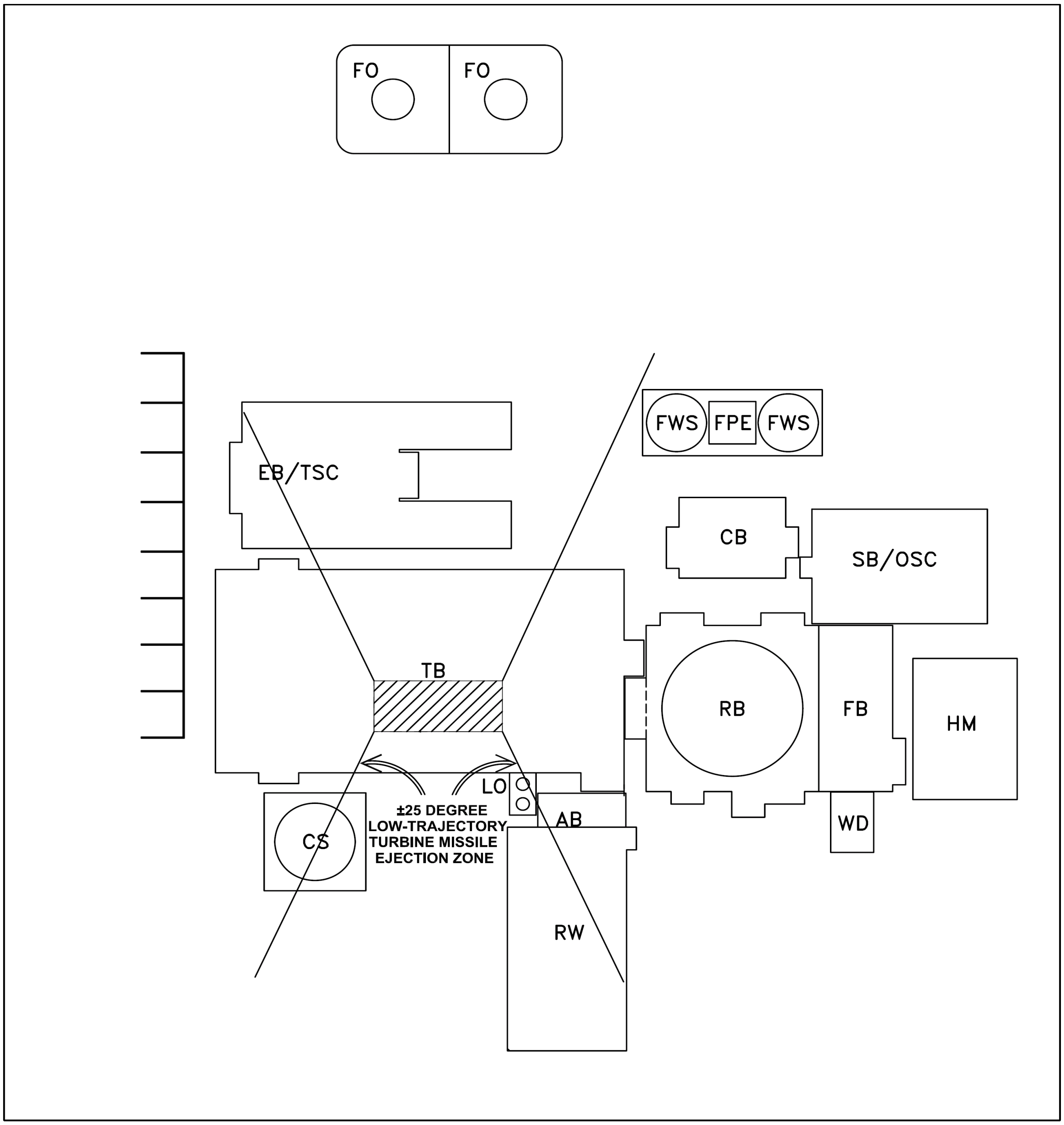

See Figure 1.1-1 for nomenclature.

Figure 3.5-2. ESBWR Standard Plant Low-Trajectory Turbine Missile Strike Zone