CONCORD ASSOCIATES, INC.

Systems Performance Engineers

CA/TR 95-019-38

HOPE CREEK GENERATING STATION

TECHNICAL EVALUATION REPORT ON THE IPE SUBMITTAL HUMAN RELIABILITY ANALYSIS

FINAL REPORT

by

P.J. Swanson

Prepared for

U.S. Nuclear Regulatory Commission
Office of Nuclear Regulatory Research
Division of Systems Technology

Draft Report, January 13, 1995
Final Report, December 27, 1995

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Contract No. NRC-04-91-069
Task Order No. 38

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E. EXECUTIVE SUMMARY

This Technical Evaluation Report (TER) is a summary of the documentation-only review of the human reliability analysis (HRA) presented as part of the Public Service Electric and Gas Company (PSE&G) Individual Plant Examination (IPE) submittal for the Hope Creek Generating Station (HCGS) to the U.S. Nuclear Regulatory Commission (NRC). The review was performed to assist NRC staff in their evaluation of the IPE and conclusion regarding whether the submittal meets the intent of Generic Letter 88-20.

E.1 Plant Characterization

The Hope Creek Generating Station (HCGS) is operated by Public Service Electric and Gas Company (PSE&G) and is located approximately 18 miles south of Wilmington, Delaware and 30 miles southwest of Philadelphia, Pennsylvania. The HCGS employs a General Electric boiling water reactor, type BWR-4. The unit uses a Mark 1 containment and a natural draft cooling tower. The HCGS began commercial operation in December 1986. HCGS design features which impact core damage frequency (CDF) relative to other BWR 4 plants include; 1) four diesel generators, 2) both pumps required in SACS and SSW loops, 3) four hour battery lifetime, 4) ability to use alternate injection to the vessel, and 5) automatic actuation of SLC.

E.2 Licensee IPE Process

The HRA process addressed both pre-initiator actions (performed during maintenance, test, surveillance, etc.) and post-initiator actions (performed as part of the response to an accident). Pre-initiator actions considered included both restoration errors and miscalibration. Post-initiator actions included both response-type and recovery-type actions. Post-initiator HRA was performed using the Systematic Human Action Reliability Procedure (SHARP), EPRI NP-3583. The particular methods applied to quantify human errors under SHARP included the Technique for Human Error Prediction (THERP), NUREG/CR-1278 for pre-initiator actions, and a combination of the Accident Sequence Evaluation Program (ASEP), NUREG/CR-4772 and the EPRI NP-6560L methodologies for post-initiator actions. Plant-specific performance shaping factors and dependencies were considered to some degree in both pre-initiator and post-initiator analyses. Human errors were identified as significant contributors in accident sequences leading to core damage, and human-performance-related enhancements were identified and credited in the IPE/HRA or cited for future consideration. PSE&G employed the service of Haliburton, NUS to perform the HRA. Licensee staff with knowledge of plant design, operations and maintenance worked with the contractor throughout the HRA process. Procedures reviews, interviews with operations staff, and plant walkdowns helped assure that the IPE represented the as-built, as-operated plant. An independent review to assure appropriate use of HRA techniques was performed by a peer review team comprised of an contractor and PSE&G staff not involved with the actual performance of the HRA.

E.3 Human Reliability Analysis

E.3.1 Pre-Initiator Human Actions.

The licensee used the ASEP methodology to screen identify pre-initiator human events to be included in the analysis. A review of HCGS's maintenance, surveillance, test, and calibration procedures was performed to help facilitate identification of pre-initiator human events. The involvement of plant operators and analysts appear adequate to assure a comprehensive assessment of restoration and misalignment errors. There is no mention of maintenance personnel participation in identification and selection of pre-initiator errors (i.e., calibration and restoration errors), but it does appears that maintenance personnel were involved in the review process.

There was no numerical screening performed for pre-initiator human errors.

Miscalibration and restoration errors were quantified using the Handbook of Human Reliability With Emphasis on Nuclear Power Plant Operations and the Technique for Human Error Rate Prediction (THERP). Detailed HCGS-specific HRA event trees were developed for miscalibration, dependent miscalibration of three channels, and restoration error following test or maintenance. The licensee did not attempt to develop task-specific THERP trees for each maintenance procedure but applied a single value for miscalibration error rates and another single value for restoration error rates. Events associated with dependent miscalibration of two instruments and dependent miscalibration of three instruments were each assigned a single value as well. PSE&G's states that "a conservative approach to envelop the task by taking advantage of similarities in the procedures" was used. As an additional check on reasonability for their approach, the licensee performed a sensitivity study to bound the effects of potential underestimates of miscalibration HEPs. A total of 25 restoration errors and 66 miscalibration errors were included in the fault tree models.

Overall, HCGS's approach for quantifying pre-initiator errors is consistent with the recommendations of the HRA methodology applied.

E.3.2 Post-Initiator Human Actions.

The HCGS IPE addresses activities performed by crews during and after the occurrence of an abnormal event with both response and recovery type actions in post-initiator analysis.

In general, HCGS procedures for system operating, emergency operating, abnormal operating, and alarm response were used to identify and group human actions. The process involved a review of human actions modeled in the system fault trees, through which the analyst identified those operator actions that include manual operation or alignment of components that must be manually initiated and controlled or backup automatic operation. A list of 41 actions treated in the fault trees is provided in the submittal. Recovery actions were applied in transients, ATWS events, and to the longer-term events such as loss of decay heat removal. If several actions were applicable to a cutset, then the actions with the lowest unavailability was applied. The licensee used a numerical screening process to identify and select post-initiator actions for refined analysis. The screening process outlined in the ASEP methodology was used. Operator actions that appeared only in cutsets lower than 1.0E-07/yr or less were left in the fault tree models at the screening value of 1.0. Operator actions that appeared in cutsets greater than 1.0E-7/yr were evaluated further using refined HEP estimates and sequences with no operator action modeled were examined to identify potential recovery actions. Additionally, all sequences which would have been above the cutoff criteria were it not for low human error probabilities in recovery actions are well documented with detail discussion as requested in NUREG-1335.

The human events not screened out were quantified using recommended HEP values from ASEP for slips (P3) and mistakes (P1). For non-responses (P2), the simulator based model in EPRI NP-6560L was substituted for the fixed time curves in ASEP. This allowed incorporation of generic and plant-specific information into the assessments. The time available for operators to respond was determined primarily by a combination of severe accident codes (MAAP), and simulator observations without operator actions under specified conditions. Finally the three estimates for detection errors (P1), non-response (P2), and post-initiator action errors (P3) were merged into a HEP, and an uncertainty bounds (UCB) as recommended in ASEP was assigned. Forty refined human response and recovery actions were included in the final analysis.

Overall the HCGS's treatment of post-initiator human actions appears reasonably thorough and complete. Results from HCGS's HRA are generally consistent with similar BWR 4 plant reviewed.

E.4 Generic Issues and CPI

The licensee's consideration of generic safety issues (GSIs) and unresolved safety issues (USIs) and of containment performance improvements (CPI) recommendations are the subject of the front-end review, and back-end review, respectively. The HCGS IPE addresses two generic issues, USI A-45 - Decay Heat Removal, and GSI 105 - Intersystem LOCA Outside Containment.

The analysis of DHR reported in submittal consideration of operator actions typically found in the DHR analysis of other IPEs for similar plants. The licensee credits the closure of Unresolved Safety Issue (USI) A-45 as a result of this analysis. The Interfacing System LOCA (ISLOCA) event trees contain human actions for early isolation, RPV depressurization, establishment of other make-up sources, and late isolation. The licensee states that in the case of operator action for early isolation of rupture of the Containment Spray (CS) pumps discharge line, the error probability was obtained with order of magnitude estimates (study performed by ERIN) instead of a detailed HEP analysis. For operator action in late isolation of a rupture of CS pumps discharge line, the operator action was assigned a conservative value of 0.5 because of the uncertainty associated with the operation of the valve (harsh environment), and dependency on previous operator errors. Simulator exercise observations are credited with discovering several insights related to leak isolation during LOCA. Specifically, identification of ruptures/leaks from diverse information systems provided to the control room operating personnel and actions to isolate leaks.

E.5 Vulnerabilities and Plant Improvements

The HCGS IPE defines vulnerability based on NUREG-1335 screening criteria for reporting systemic sequences. To be considered a vulnerability, those sequences meeting the screening criteria must also contribute inordinately to the CDF with respect to either (1) other sequences or events in the IPE, or (2) in comparison with PRA results for other plants.

In the licensee's analysis, transients involving HVAC failure were determined to contribute inordinately to the CDF. For example, loss of switchgear or 1E panel room cooling had an initial CDF of 3.29E-3/yr. In response to this vulnerability the licensee developed a new procedure for providing alternate methods for panel room cooling. The sequence analysis was repeated and credit was taken for the new procedure which resulted in a reduction of sequence CDF to 9.87E-7/yr. Operator recovery action associated with the new procedure includes taking steps to provide alternative cooling means for electrical equipment in these rooms, i.e., open doors, placement of portable fans, etc,. A human error probability of 3.0E-04 was assigned to this action. This is a relatively low value for an HEP, but typical of values seen in other IPE analysis where explicit procedural guidance, considerable time available for accomplishment (12 hours), and emphasis in training is identified.

Additionally, the licensee initiated a detailed review of the success criteria for SSW and SACS to see if some of the conservatism presently in the model could be relaxed by crediting additional operator action. A new procedure for operating SACS with one pump per loop was thought to result in a substantial improvement in CDF resulting from SBO. The licensee reports in their response to NRC's request for additional information that after detailed evaluation it was determined that little benefit was to be derived by taking credit for this operator action.

E.6 Observations

The following observations from our document-only review are pertinent to NRC's determination of whether the licensee's submittal meets the intent of Generic Letter 88-20.

The submittal and supporting documentation indicates that utility personnel were involved in the HRA, and that the walkdowns and documentation reviews constituted a viable process for confirming that the HRA portions of the IPE represent the as-built, as-operated plant. The licensee performed an in-house peer review that provides some assurance that the HRA techniques have been correctly applied and that documentation is accurate.

The licensee's analysis of pre-initiator human actions was reasonably complete, though simplified and relatively generic. Identification and selection of human actions to be quantified included review of calibration, test and maintenance procedures and discussion with plant personnel. Both calibration and restoration errors were included. No numerical screening was performed; qualitative screening that appears to be rational and consistent with other PRAs eliminated some actions from consideration. All actions surviving the qualitative screening were included in the IPE model as basic events in fault trees. The quantification used THERP to analyze four "generic" pre-initiator actions that represented all pre-initiator actions included in the model. Plant-specific and certainly case-specific analysis was very limited. This limits the ability of the licensee to identify factors contributing to human error and therefore plant risk and to identify possible enhancements. However, the analysis appears to have been effective in identifying the relative importance of contributions from pre-initiator human errors.

The treatment of post-initiator human actions included both response-type and recovery-type actions. The process for identification and selection of post-initiator human actions included review of procedures and discussion with plant operations and training staff. Numerical screening based on guidance in the ASEP methodology was employed to eliminate actions or sequences from further consideration. Quantification of human error used the ASEP and EPRI NP-6560-L processes for detailed calculations. The guidance for methodologies used appears to have been followed by the licensee. Evaluation of plant-specific performance shaping factors was included, consistent with the simplified ASEP process; and, error recovery factors were included according to ASEP guidance. Dependencies among post-initiator actions were treated in a manner consistent with the ASEP dependency model.

The process used by the licensee to obtain plant-specific data for representation of performance shaping factors, which included simulator exercises, procedure walkdowns and discussion with key plant personnel, is considered a strength in their HRA.

The licensee employed a systematic process to screen for vulnerabilities and identify potential enhancements. Vulnerability screening criteria included NUREG-1335 reporting criteria plus a comparison with other PRA results to identify unusual contributors. In the licensee's analysis, transients involving HVAC failure were determined to contribute inordinately to the CDF. For example, loss of switchgear or 1E panel room cooling had an initial CDF of 3.29E-3/yr. In response to this vulnerability the licensee developed a new procedure for providing alternate methods for panel room cooling. The sequence analysis was repeated and credit was taken for the new procedure which resulted in a reduction of sequence CDF to 9.87E-7/yr. Operator recovery action associated with the new procedure includes taking steps to provide alternative cooling means for electrical equipment in these rooms, i.e., open doors, placement of portable fans, etc,.

1. INTRODUCTION

This Technical Evaluation Report (TER) is a summary of the documentation-only review of the human reliability analysis (HRA) presented as part of the Public Service Electric and Gas Company (PSE&G) Individual Plant Examination (IPE) submittal for the Hope Creek Generating Station (HCGS) to the U.S. Nuclear Regulatory Commission (NRC). The review was performed to assist NRC staff in their evaluation of the IPE and conclusion regarding whether the submittal meets the intent of Generic Letter 88-20.

1.1 HRA Review Process

The HRA review was a "document-only" process which consisted of essentially four steps:

(1) Comprehensive review of the IPE submittal focusing on all information pertinent to HRA.

(2) Preparation of a draft TER summarizing preliminary findings and conclusions, noting specific issues for which additional information was needed from the licensee, and formulating requests to the licensee for the necessary additional information.

(3) Review of preliminary findings, conclusions and proposed requests for additional information (RAIs) with NRC staff and with "front-end" and "back-end" reviewers.

(4) Review of licensee responses to the NRC requests for additional information, and preparation of this final TER modifying the draft to incorporate results of the additional information provided by the licensee.

Findings and conclusions are limited to those that could be supported by the document-only review. No visit to the site was conducted. No review of detailed "Tier 2" information was performed, except for selected details provided by the licensee in direct response to NRC's request for additional information (RAIs). In general it was not possible, and it was not the intent of the review, to reproduce results or verify in detail the licensee's HRA quantification process.

1.2 Plant Characterization

The Hope Creek Generating Station (HCGS) is operated by Public Service Electric and Gas Company (PSE&G) and is located approximately 18 miles south of Wilmington, Delaware and 30 miles southwest of Philadelphia, Pennsylvania. The HCGS employs a General Electric boiling water reactor, type BWR-4. The unit uses a Mark 1 containment and a natural draft cooling tower. The HCGS began commercial operation in December 1986. HCGS design features which impact core damage frequency (CDF) relative to other BWR 4 plants include; 1) four diesel generators, 2) both pumps required in SACS and SSW loops, 3) four hour battery lifetime, 4) ability to use alternate injection to the vessel, and 5) automatic actuation of SLC.

2. TECHNICAL REVIEW

2.1 Licensee IPE Process

2.1.1 Completeness and Methodology.

The HCGS submittal is a Level 2 PRA with HRA components in both Level 1 and Level 2 analysis. The freeze date of the IPE model was August, 1993. One change to the plant after the freeze date was incorporated into the IPE model, that being the incorporation of a new procedure for the recovery of HVAC to electrical equipment areas.

The submittal provides a reasonably complete summary of the HRA methodology. The primary leadership of the HRA and all calculation of human errors was performed by Haliburton NUS, with PSE&G engineers providing technical assistance throughout the process. HCGS staff with knowledge of plant design, operations and maintenance appear to have had significant involvement in the HRA. The IPE discussion on accident sequence delineation (event trees), systems analysis, internal flooding analysis, decay heat removal (A-45), and back-end analysis, all provide reasonably complete descriptions of important human actions addressed. Human-performance related insights and enhancements are identified.

The HRA process was performed under the Systematic Human Action Reliability Procedure (SHARP), EPRI NP-3583 (Reference 1). The licensee considered both pre-initiator actions (performed during maintenance, test, surveillance, etc.) and post-initiator actions (performed as part of the response to an accident) in their analysis. The primary HRA techniques employed to quantify human error included the Technique for Human Error Prediction (THERP), (Reference 2) for pre-initiator actions, and elements of the Accident Sequence Evaluation Program (ASEP), (Reference 3) and EPRI NP-6560L (Reference 4) for post-initiator actions. Plant-specific factors were considered in both pre-initiator and post-initiator analyses. The quantification results (HEPs) for those actions which the licensee performed "refined" analysis are summarized in the Submittal, but details on the analysis of specific events is somewhat limited. PSE&G did provide in their response to NRC's request for additional information (RAI), complete and thorough documentation on the quantification process for several requested human error events. The Level 2 analysis used a different approach for treating human actions. In Level 2 analysis, the HRA was performed using the Dougherty and Fragola, TRC methodology.

2.1.2 Multi-Unit Effects and As-Built, As-Operated Status

HCGS is a single unit plant which shares a common site with two Salem units. The only shared system appears to be the electrical switchyard(s) were each plant can receive off-site power via the others switchyard. This interface does not influence the HRA.

The assembly of information needed to support the IPE included the involvement of HCGS Engineering, Operations, and Training Department personnel. This process included review and assessment of plant documentation, multiple plant system walkdowns, and review of several PRAs for other BWRs. Documentation used in the IPE included: procedures (emergency, operating, test, maintenance and surveillance), UFSAR, and design basis documents. Overall, the submittal documentation and RAI responses indicate that the licensee took steps to provide reasonable assurance that the HRA-related aspects of the IPE model represented the as-built, as-operated plant during the time frame of the IPE development.

2.1.3 Licensee Participation and Peer Review.

The overall coordination of the Level 1 PRA was under the responsibility of PSE&G's Nuclear Engineering Department, Probablistic Risk Assessment Group. This group provided engineers to support the study, performed portions of the PRA tasks, and reviewed the results. The technical direction of the effort, training of PSE&G's staff, and major portions of the analysis were provided by contractors. Those contractors involved in the HCGS effort include SAIC, Halliburton NUS, Gabor, Kenton and Associates, ERIN, ABB Implell, and Reliability and Performance Associates (RAPA).

The primary leadership for the HRA and all evaluations of human errors was performed by PSE&G's contractor with a PSE&G engineer providing technical assistance throughout the process (IPE Section 2.1.4). Additionally, technically knowledgeable PSE&G and HCGS personnel participated throughout the IPE process, including the review of all applicable plant-specific procedures. The utilities staff involvement in the IPE appears to be comprehensive and extensive.

We believe that the utility personnel involvement in the development and application of PRA techniques to their facility and the associated walkdowns and documentation reviews constituted a viable process for confirming that the IPE represents the as-built and as-operated plant.

An independent review of the IPE and associated documentation was performed in two phase approach. First, a senior level review of ongoing work was done by PSE&G's review team leader and consultants. Then, a formal review team was assembled with personnel from PSE&G's Nuclear Engineering Department who were not involved with the development of the IPE. A contractor from the consulting firm of RAPA, served as technical lead for the independent formal review. All personnel involved in the review appear to have an appropriate level of experience and expertise which complements one-another in covering the entire range of the IPE. The review process for the HCGS IPE is well documented and appears reasonable.

In our opinion, the reviews appear to constitute a reasonable process for an "in-house" peer review that provides some assurance that the IPE analytic techniques were correctly applied and that documentation is accurate.

2.2 Pre-Initiator Human Actions

Errors in performance of pre-initiator human actions (i.e., actions performed during maintenance, testing, etc.) may cause components, trains, or entire systems to be unavailable on demand during an accident, and thus may significantly impact plant risk. Our review of the HRA portion of the IPE examines the licensee's HRA process to determine what consideration was given to pre-initiator human actions, how potential actions were identified, the effectiveness of quantitative and/or qualitative screening process(es) employed, and the processes for accounting for plant-specific performance shaping factors, recovery factors, and dependencies among multiple actions.

2.2.1 Pre-Initiator Human Actions Considered.

Pre-initiator (pre-accident) human errors modeled in the HCGS IPE are those related to the tasks of testing and maintenance. Errors in performing these tasks include miscalibration of sensors and failure to restore components following a test or maintenance activity.

2.2.2 Process for Identification and Selection of Pre-Initiator Human Actions.

The key concerns of the NRC staff review regarding the process for identification and selection of pre-initiator human events are: (a) whether maintenance, test and calibration procedures for the systems and components modeled were reviewed by the systems analyst(s), and (b) whether discussions were held with appropriate plant personnel (e.g., maintenance, training, operations) on the interpretation and implementation of the plant's test, maintenance and calibration procedures to identify and understand the specific actions and the specific components manipulated when performing the maintenance, test, or calibration tasks.

The licensee states in IPE Section 3.3.3.2, that the "methods used to assess pre-initiator operator actions are consistent with the NUREG/CR-4772 and the NUREG/CR-4550 studies." The licensee reviewed HCGS's maintenance, surveillance, test, and calibration procedures to identify the pre-initiator human events to be used in the analysis. From our review of the pre-initiators reported it appears that selection of specific channels to be considered in the analysis of miscalibration error was based on a functional criteria. Also, the licensee evaluated the valves in standby systems to determine whether a restoration error could result in partial or total failure of the system to perform its required function. We believe the involvement of plant operators and analysts was adequate for a comprehensive assessment of restoration and misalignment errors. There is no mention of maintenance personnel participation in identification and selection of pre-initiator errors (i.e., calibration and restoration errors), but it does appears that maintenance personnel were involved in the review process.

2.2.3 Screening Process for Pre-Initiator Human Actions.

There was no numerical screening performed for pre-initiator human errors. The licensee cites the criteria which they used to screen out restoration/misalignment errors, namely:

- components realigned upon demand,
- components which must be tested upon completion of maintenance,
- components which are not affected by maintenance and,
- misalignments that would be noticed on a shift basis, or would be annunciated.

Screening on the basis of "misalignments that would be noticed on a shift basis, or would be annunciated" could result in important human errors being eliminated if the criterion is applied to informal observations. When used in connection with formal administrative control procedures, such as surveillance procedures for logging Technical Specification cited parameters on a shift basis, we believe taking credit for "noticed on a shift basis" would be appropriate. In response to NRC's request for additional information the licensee provided "tier 2" documentation for identifying events screened out. Our review of this documentation indicates that the licensee's application of the criteria appears reasonable and should not have eliminated important human error.

2.2.4 Quantification of Pre-Initiator Human Actions.

The probability of error in performing pre-initiator human actions can vary substantially (up or down) from "generic" estimates because of plant specific factors affecting human performance. Plant-specific "recovery factors" that exist due to plant design features or operational practice, or dependencies among multiple restoration/miscalibration tasks that may exist as a result of "systemic," but perhaps subtle, human performance problems in training, procedures, etc. If the licensee is to gain a realistic understanding of the potential impact of pre-initiator human error on plant risk, it is important that the HRA include a reasonably rigorous assessment of these plant-specific factors and dependencies. While the numerical HEP estimate is important, the benefit gained from the pre-initiator HRA is to a large degree a function of the rigor of this more qualitative evaluation of plant-specific factors.

Miscalibration and restoration errors were quantified using the Handbook of Human Reliability With Emphasis on Nuclear Power Plant Operations and the Technique for Human Error Rate Prediction (THERP). IPE Tables 3.3.3-1 and 3.3.3-4 present the conditions and procedures (administrative controls) associated with calibration and maintenance/restoration respectively. These conditions and procedures are used to support the selection of the specific THERP tables and specific values therein used to quantify the HRA event trees (THERP models). General assumptions/administrative controls which were used by the analyst in quantifying calibration errors include:

- Calibration is normally performed every 3, 6, 12, or 18 months as applicable.

- Each calibration is covered by a separate procedure.

- Calibration teams normally involve two or more people; one person perform the calibration and the other person observes the work and checks off each step as it is completed.

- Procedure sheets have a before calibration reading entry and an after calibration entry which are to be compared when calibration is completed (prior to shift foreman sign-off).

- The I&C maintenance foreman checks the consistency of "before-and-after" readings after the calibration. This is accomplished within three working days.

- Some of the instrument panel checks are completed by reactor operators observing the indicated value from the calibrated instrument, and comparing those readings with other instrument readings.

- Calibration procedures involve a second person or group to check the procedure.

- I&C technicians can close and open most instrument sensing line valves with approved test procedures and shift foreman permission. Other sensing line valves must be closed (and opened) by an operator.

For restoration or misalignment type pre-initiator errors, the following assumptions/ administrative controls were applied:

- Scheduled maintenance (involves routine preventative maintenance performed on a regular schedule) may be performed while the unit is at power.

- Unscheduled maintenance (corrective maintenance performed when a component fails) can be performed during power operation, within the Technical Specification guidelines.

- Most maintenance acts have an applicable set of procedures.

- Operations personnel perform all isolation before maintenance and realignment after maintenance.

- After maintenance is complete, the shift supervisor approves removal of the blocking tags.

- Maintenance teams normally involve two or more people; one or more to perform the maintenance and, one person to observe the work and check off each step as it is completed, if there is an applicable procedure.

- Each component maintained is tested for proper operation following maintenance, if required.

- The maintenance supervisor verifies that blocking tags are physically in place for personnel safety prior to allowing any personnel to start work on a component.

- When components in safety-related systems are tagged out, and again when the tags are released, a second operator independently verifies the tag/release. This is in addition to the maintenance personnel verification.

The submittal includes the detailed HCGS-specific HRA event trees for miscalibration (Table 3.3.3-2), dependent miscalibration of three channels (Table 3.3.3-3), and restoration error following test or maintenance (Table 3.3.3-5). A detailed examination of plant-specific calibration and restoration (following maintenance) procedures was performed by the licensee to ensure technical accuracy of the plant-specific models. The licensee applied a single value of 3.0E-03 per calibration for miscalibration error rates and 5.0E-3 per test or maintenance for restoration error rates. Dependent miscalibration of two instruments was assigned a probability of 5.0E-4, while dependent miscalibration of three instruments was assigned 3.0E-4. Dependent restoration errors were treated as contributors to the beta and gamma factors for common cause failures.

Component unavailability (UA), due to miscalibration or restoration, was determined with the following equation:

$$UA = (HEP)\ (FDT)\ (INTRVL)$$

where;

HEP = miscalibration (or restoration) error probability
FDT = fault duration time before detection, and
INTRVL = interval between calibrations (test or maintenance).

The licensee considered a total of 25 restoration errors and 66 miscalibration errors in the fault tree models.

Overall, HCGS's approach for quantifying pre-initiator errors is generally straight forward and appears consistent with the recommendations of the Handbook. However, the pre-initiator HRA did not attempt to develop task-specific THERP trees for each maintenance procedure but used what PSE&G terms as "a conservative approach to envelop the task by taking advantage of similarities in the procedures". As an additional check on reasonableness of their approach, the licensee performed a sensitivity study to bound the effects of potential underestimates of miscalibration HEPs. All events were simultaneously increased by a factor of 10 in the model which resulted in an increased of CDF by 28%. The major contributor to the change noted in CDF was attributed to the effect of miscalibration on the ESF (actuation) support system.

2.3 Post-Initiator Human Actions

Human errors in responding to an accident initiator, e.g., by not recognizing and diagnosing the situation properly, or failure to perform required activities as directed by procedures, can have a significant effect on plant risk. These errors are referred to as post-initiator human errors. Our review assesses the types of post-initiator errors considered by the licensee, and evaluates the processes used to identify and select, screen, and quantify post-initiator errors, including issues such as the means for evaluating timing, dependency among human actions, and other plant-specific performance shaping factors.

2.3.1 Types of Post-Initiator Human Actions Considered.

There are two important types of post-initiator actions considered in most nuclear plant PRAs: (1) response actions, which are performed in response to the first level directives of the emergency operating procedures/instructions (EOPs, or EOIs); and, (2) recovery actions, which are performed to recover a specific failure or fault, e.g., recovery of offsite power or recovery of a front-line safety system that was unavailable on demand earlier in the event. The HCGS IPE addresses activities performed by crews during and after the occurrence of an abnormal event with both response and recovery type actions in post-initiator analysis. In the discussion of "refined" analysis performed, the submittal refers to all post-initiator actions as recovery actions.

2.3.2 Process for Identification and Selection of Post-Initiator Human Actions.

The primary thrust of our review related to this question is to assure that the process used by the licensee to identify and select post-initiator actions is systematic and thorough enough to provide reasonable assurance that important actions were not inappropriately precluded from examination. Key issues are whether: (1) the process included review of plant procedures (e.g., emergency/abnormal operating procedures or system instructions) associated with the accident sequences delineated and the systems modeled; and, (2) discussions were held with appropriate plant personnel (e.g., operators or training staff) on the interpretation and implementation of plant procedures to identify and understand the specific actions and the specific components manipulated when responding to the accident sequences modeled.
The submittal states that key operator actions that could have an impact on the consequence of an event sequence were selected using three methods. In general, HCGS procedures for system operating, emergency operating, abnormal operating, and alarm response were used to identify and group human actions. The first method addresses human actions modeled in the system fault trees, through which the analyst identified those operator actions that include manual operation or alignment of components that must be manually initiated and controlled or backup automatic operation. A list of 41 actions treated in the fault trees is provided in

Table 3.3.3-7 of the submittal. The second method presented involves recovery actions applied to sequence cutsets. Here the recovery actions were applied in transients, ATWS events, and to the longer-term events such as loss of decay heat removal. If several actions were applicable to a cutset, then the action with the lowest unavailability was applied. Specific details on the formulation of specific timing criteria and determination of which actions did or did not meet timing criteria are not provided in the submittal. Finally, refined recovery actions were selected to replace combined human actions. These recovery actions are typically cutset dependent. Therefore, they were applied at the cutset level after the initial sequence cutsets had been grouped into similar sequences.

2.3.3 Screening Process for Post-Initiator Response Actions.

Initial screening of post-initiator errors was quantified with all actions identified in the initial models set to 1.0 in order to see all combinations of operator actions to ensure that all dependencies of operator actions were known. However, there were an unmanageable number of cutsets which would have dropped below the reporting screening criteria once the recovery actions were applied. Therefore in a second screening step a new value of 0.1 was assigned. This resulted in many cutsets with 1 to 3 human actions combined with several equipment failures. The value of each of those human actions was then assigned a probability of 1.0. The resulting cutsets were examined, and if the recovery actions were separate in time, then the screening process outlined in the ASEP procedure was used. For example, if the first recovery action in a cutset was based on a detailed quantification, then the second action was included in the quantification by multiplying the greater of either the detailed HEP assessment for the second action or 0.03 as recommended for screening the guidance document. If a third action was identified, a HEP of 0.1 was assigned (or detailed assessment HEP, if greater). The licensee states that this process accounts for human action dependencies during the sequence quantification.

Operator actions that only appeared in sequences lower than 1.0E-07/yr or less were left in the fault tree models at the screening value of 1.0. Operator actions that appeared in sequences greater than 1.0E-7/yr were evaluated further using refined HEP estimates and sequences with no operator action modeled were examined to identify potential recovery actions.

Additionally, all sequences which would have been above the cutoff criteria were it not for low human error probabilities in recovery actions are well documented with detail discussion as requested in NUREG-1335.

2.3.4 Quantification of Post-Initiator Human Actions.

The human events not screened out were quantified using recommended HEP values from NUREG/CR-4772 for slips (P3) and mistakes (P1). For non-responses (P2), the simulator based model in EPRI NP-6560L was substituted for the fixed time curves in NUREG/CR-4772. This allowed incorporation of generic and plant-specific information into the assessments. The time available to operators to respond was determined primarily by a combination of severe accident codes (MAAP), and simulator observations without operator actions under specified conditions. This accounted for combinations of working and inoperative control systems. The transient information was used to estimate the time to core uncovery, conditions for actions to protect the suppression pool, and construction of timing information for cutset analysis. Finally the three estimates for detection errors (P1), non-response (P2), and post-initiator action errors (P3) were merged into a HEP and an UCB as recommended in NUREG/CR-4772 was assigned.

Operator actions that proved to be dominant contributors to accident sequence underwent further analysis by means of a refined (normal) HRA. The refined analysis was performed using NUREG/CR-4772 analysis procedure and time dependent model and data developed in EPRI-6560L. The refined assessment reduced conservatism introduced through HRA screening, and identified specific actions that are important for maintaining the risk and the expected level. Table 2.2-1 lists the 40 human recovery (response and recovery) actions and results for those operator actions subjected to refined analysis. The licensee did not distinguish between response and recovery actions in their analysis, both were treated with the same analysis with exceptions noted.

Table 2.2-1, Post-Initiator Operator Response and Recovery Actions Modeled.

IDENTIFIER	DESCRIPTION	HEP
NR-AIR-24	Failure to recover the IAS within 24 hours	5.7E-3
NR-ATWS-ADS-INH	Failure to inhibit ADS during an ATWS	7.5E-2
AR-ATWS-ARI	Failure to manually initiate ARI	1.4E-2
NR-ATWS-DEP	Failure to manually depressurize the PRV during an ATWS	5.6E-2
NR-ATWS-HPCI-30M	Failure to initiate HPCI during an ATWS	5.0E-2
NR-ATWS-HPCI-CS	Failure to isolate HPCI injection through the Core Spray piping during an ATWS	2.4E-1
NR-ATWS-LCNTL-LO	Failure to control RPV water level with LPCI during an ATWS	4.7E-1
NR-COND-5	Failure to restart condensate pumps after other injection systems fail	3.7E-2
NR-DG-6	**Failure to recover D/Gs within 6 hrs (independent failures of D/Gs)[1]**	**7.0E-1**
NR-DG-DF-6	**Failure to recover D/Gs within 6 hrs (common cause failures of D/Gs)[1]**	**6.0E-1**
NR-HPCI-LCNT-HIE	Failure to control RPV water level using HPCI during an ATWS to prevent core damage	4.6E-2
NR-HVC-PNRM-12	**Failure to provide alternate ventilation to the Panel Room within 12 hrs after loss of HVAC[1]**	**3.0E-4**
NR-HVC-SWGR-24	Failure to provide alternate ventilation to the Switchgear Room within 24 hrs after loss of HVAC	1.6E-4
NR-IGS-24	Failure to restart the EIAC after RACS cooling has been restored following a LOCA isolation	3.8E-3
NR-LOSP-24	Failure to restore offsite power within 24 hrs	2.2E-3
NR-LOSP-12	Failure to restore offsite power within 12 hrs	1.5E-2
NR-LOSP-6	**Failure to restore offsite power within 6 hrs[1]**	**5.0E-2**
NR-LOSP-5	Failure to restore offsite power within 5 hrs	7.0E-2
NR-LOSP-1	Failure to restore offsite power within 1 hour	4.0E-1
NR-LOSP-40M	Failure to restore offsite power within 40 minutes	5.5E-1
NR-LOSP-30M	Failure to restore offsite power within 30 minutes	6.0E-1

NR-PCS-24	Failure to restore the PCS within 24 hrs following a turbine trip or MSIV closure initiating event	7.0E-4
NR-PCS-1	**Failure to restore the PCS within 1 hour[1]**	**6.0E-1**
NR-PCS-40M	Failure to restore the PCS within 40 minutes	9.0E-1
NR-Q-FWLVH-4M	Failure to prevent a level 8 trip of feedwater during a transient	1.4E-2
NR-Q-FWLVL-24M	Failure to prevent a level 8 trip of feedwater during a small LOCA	4.9E-3
NR-RACS-24	Failure to restore the RACS after a LOCA isolation	3.8E-3
NR-RHR-INIT	Failure to initiate RHR for decay heat removal within 24 hrs	5.0E-5
NR-SLEAK-ISO-15M	Failure to isolate recirculation pump seal LOCA	8.2E-2
NR-SPL-LVLL-4	**Failure to align core spray to the CST for long-term injection (without DHR)[1]**	**1.1E-1**
NR-U1X-DEP-30M	**Failure to manually depressurize the RPV within 30 minutes[1]**	**7.5E-3**
NR-U1X-DEP-40M	Failure to manually depressurize the RPV within 40 minutes	5.2E-3
NR-U1X-DEP-60M	**Failure to manually depressurize the RPV within 1 hour[1]**	**4.6E-3**
NR-UV-ECCS-1	Failure to manually initiate ECCS within 1 hour	3.9E-2
NR-UV-WTLVL-20M	Failure to control RPV water level with high pressure injection systems (non-ATWS)	4.3E-2
NR-VENT-5	Failure to initiate containment venting	2.0E-3
NR-WW1-SWP-1	Failure to manually start SSWS or SACS pumps within 1 hour	1.2E-2
NR-WW1-SWP-12	Failure to manually start SSWS or SACS pumps within 12 hours	1.9E-4
NR-WW1-SWP-20	Failure to manually start SSWS or SACS pumps within 20 hours	7.4E-5
NR-WW1-SWP-40M	Failure to manually start SSWS or SACS pumps within 40 minutes	1.6E-2

[1] This action appears in the top 30 event failures as determined by risk reduction measure.

The quantification process used by the licensee to complete the refined assessment which generated the above listed results includes the following 11 steps:

1) Define recovery actions that decrease a sequence below 1E-7/yr whose screening value is less than 0.1 for a cutset. This includes the combination of all recovery actions modeled in the fault trees and non-recovery actions that result from the examination of the information contained in the cutset. The qualitative insights gained from simulator observations were used to define the nature of the recovery action.

2) For the recovery actions that are not included in the fault trees, apply the appropriate recovery action identifier to the cutset.

3) Starting with the Basic HEPs for errors of omission and commission in NUREG/CR-4772 (treated as slips-errors in actions P1 and mistakes - errors in diagnosis P3 in EPRI-6560L), apply the PSFs for procedures, practice feedback, interface designs, stress and task complexity.

$$P1 = PSFs1 * HEPo$$

$$P3 = PSFs3 * HEPc$$

4) Estimate the time dependent part of the non-recovery probability by first determining the times for action and system time allowed. These times can be determined from thermal-hydraulic calculations, simulator observations, experienced events, or expert judgement as recommended in NUREG/CR-4772. Specifically,

   TM (the maximum time in which both phases of the recovery action must be completed) is estimated using thermal-hydraulic computer codes which provide time dependent information on core or containment parameters (i.e., pressure, temperature, water level, etc.), and/or information based on equipment failure characteristics (loss of room cooling, seal cooling, etc.).

   TA (the time required to physically accomplish the action phase) can be conservatively estimated as the sum of the maximum time required to reach the area where the action is be accomplished and the time required to accomplish the action - these should be based on actual measurements where possible.

   Estimate the time available to diagnose the recovery action, Td, by the following expression:

$$Td = TM - TA$$

5) Estimate the median response time, the type of cue that triggers the action or the level of cognitive processing required. Observations of simulator training, studies of procedures and walkdown of the plant support these plant-specific assessments. Options are to use the standard conservative curve provided in NUREG/CR-4772, or grouped data from simulator observations provided in NUREG/CR-4834 Vol 2. The desired approach in this study is to use plant-specific simulator observations, and to gain risk reduction insights through the process.

6) Obtain an estimate of the median failure probability for the time dependent non-recovery portion, P2, using the correlation from EPRI-6560L or NUREG/CR-4834 data described in step 5.

$$P2 = 1 - \phi\ [\ln(Td/Th)/\sigma]$$

   Where $\Phi(.)$ is the standard normal cumulative distribution, Td is the decision time and Th is a median time estimate for crew responses, and σ is the standard deviation of normalized time derived from data in EPRI-6560L to represent the type of cue or cognitive processing required for the task.

7) Estimate the median HEP for the action phase of the recovery task by assessing P1 and P3, and by applying the PSFs for each. Alternate methods using RMIEP, or the models the Handbook can be used. These involve the development of actions specific logic trees to represent each error.

Values for P1 and P3 were taken from NUREG/CR-4772, and from scaled simulator observations. In the case of P2, the simulator based model in EPRI NP-6560-L was substituted for the fixed time curves in NUREG/CR-4772. Use of the simulator-based model supports incorporation of generic and plant specific information.

8) Estimate the total median failure probability for the recovery action, P(NR), using the following expression:

$$P(NR\text{-}median) = P1 + P2 + P3 - (P1*P2 + P1*P3 + P3*P2)$$

9) If the detailed assessment is for the first recovery action, and second or third action is to be applied to a single cutset, apply the dependence assessment methods in NUREG/CR-4772. To consider dependencies, the HEP for multiple actions is a product of the detailed quantification for the first action, and the greater of either the detailed assessment for the second action or 0.03 as recommended for screening in the guidance document. If a third action was identified, a HEP o 0.1 was assigned (or detailed assessment HEP, if greater). This process accounts for human action dependencies during the sequence quantification. Detailed assessments of dependency can be used to justify lower dependencies on a case-by-case basis.

$$P(NR\text{-}Dep\text{-}median) = R(NR\text{-}median) * P(NR2) * P(NR3)$$

For cutsets containing hardware recoveries (e.g. recovery of offsite power, the Emergency Diesel Generators or the feedwater system), the hardware recovery was applied using its calculated value. If a second hardware recovery was applied, it was also given its detailed value. There were no cutsets which contained two hardware recoveries and any additional recoveries. For cutsets containing one hardware recovery only, up to two additional operator recoveries were allowed. the first was assigned its quantified value, and second was assigned a value of 0.03 or the HEP value, whichever was larger. Following these rules, no cutsets were allowed more than three post-accident recovery actions.

10) Specify the uncertainty on the median HEP by assigning the Uncertainty Bound (UCB) according to the ratio of the 95th percentile to the 5th percentile of the lognormal distribution. This assignment produces a lognormal distribution for the HEP distribution, determined by the median and the UCB. A calculated mean value from the lognormal distribution is typically used in quantifying the mean value of a cutset to reflect uncertainty rage int he HEP.

11) The new cutset probability, allowing for recovery, is then:

$$P(cutset)_{new} = P(cutset)\ original * P(NR\text{-}Dep\text{-}mean)$$

2.3.4.1 Consideration of Plant-Specific Factors for Response Actions. Considered a strength in the HRA is the licensee's formal process for gaining insight on performance shaping factors used in the analysis. IPE Section 3.3.3.5 discusses the plant walkdowns, operator interviews, and simulator observations used by IPE team members and consultants to enhance the plant specific understanding of key operator actions. For example, information gained from walkdown of the 300 series procedures (those involve lifting of jumpers, realigning valves and inserting piping elements) was used to estimate time required (TA). The times were formally documented in a Job Performance Measures (JPM) program administered by the Training Department. The JPM program includes data for the travel time and confirmation of the feasibility for each procedure performed outside the control room. The timing data includes the time to obtain the procedures, tools, and transient time to the local site. Additional time was added to TA for troubleshooting and carrying out the response actions such as installing the spool piece for the fire water injection based on the recommendation of operating crews interviewed during the simulator exercises. Information obtained from the walkdowns and review of the procedures included the feasibility of actions based on logistics, time availability, and ease of completion. These insights and sensitivities to operator actions expected in actual operation were used in estimating PSFs for P1 and P3.

PSFs were taken from NUREG/CR-1278, NUREG/CR-4772, and NP-6560-L, based on those considered most appropriate for HCGS after review operating procedures, discussing the use of procedures with plant personnel, and observing operations crews in plant simulator exercises.

In the quantification process PSFs for both P1 and P3 events were assessed. The particular PSFs applied are:

PSF1	PSF3
Location	Detection/diagnosis
Preassigned crews	Feedback
Practice	Procedures (100, 200)
Complexity	Consequences,
Workload	Decision making, and
Time ratio	Practice/experience
Procedures for action (300 series)	

2.3.4.2 Consideration of Timing. The HCGS plant-specific simulator was used to gain qualitative insights to support the IPE/HRA quantification. Scenarios were developed based on identified sensitivity of certain operator actions identified in the initial quantification of cutsets. Those scenarios selected included:

- Transients with turbine trip and loss of feedwater - ATWS,
- LOP - with loss of high pressure injection,
- MSIV closure - ATWS, and
- A transient with loss of all injection due to loss of service water.

The simulator exercises were performed by two different operating crews of varying experience and qualifications. Each exercise was structured to replicate the actual expected operations in the plant, including shift turnovers, and field responses to control room requests. Three observers were used to validate the sequence timing and validate the observations. The operating crew was debriefed to assess the events and circumstances surrounding the scenario. The resulting insights, observations and discussions were documented and then incorporated into the analysis in support of the medium time estimate for crew response (Th), decision time (Td), and standard deviation of normalized time (σ) during the cutset review process. The process for estimating Td is described in step 4), of the licensee's quantification guidelines cited above. The median response time, Th, was estimated from the action time lines developed from observer notes which were compared with independent measurements from other BWRs in EPRI-6560L and NUREG/CR-4834. For non-measured cases, human reliability estimates in observed cases were extrapolated using model data and engineering judgement.

2.3.4.3 <u>Consideration of Dependencies for Response and Recovery Actions.</u> An important concern in HRA is the treatment of dependencies. Human performance is dependent on sequence-specific response of the system and of the humans involved. Appropriate consideration was given the likelihood of success of a given action based on influences from the success or failure on a preceding action and performance of other team members. The HCGS analysis does not distinguish between response and recovery type actions. Dependency among top-level actions in a sequence appear to have been appropriately accounted for based on review of specific examples provided by PSE&G which document the assessment of dependencies.

The treatment of response/recovery action dependency in HCGS's analysis is stated as being the dependence assessment method in NUREG/CR-4772. As discussed under step 9 of the 11 step quantification process described in Section 2.3.4 of this report, dependency values of 0.03 and 0.1 for second and third events in a cutset were applied after operator dependencies had already been examined and treated. When recovery events within cutsets were identified, dependent individual action were merged into a single basic event. As part of the dependency assessment, observation of crews performance on the simulator demonstrated the capability to perform multiple operator actions in a short time frame. These results (team response) were said to have been used when applicable. No specific examples were identified.

Several core damage sequences were developed as a result of multiple independent system failures, but operators do not necessarily perceive these as independent. NUREG/CR-4772, Table 8-2 provided guidance for appropriate value selection in these cases.

2.3.4.4 Quantification of Recovery Actions. The HCGS HRA does not distinguish between the quantification of response and recovery actions. Estimated human error probabilities are handled in same manner as discussed in Section 2.3.4, above.

2.3.4.5 Consideration of Operator Actions in the Internal Flooding Analysis. The licensee considered internal flooding events which affect the reactor building, turbine building, and service water intake building. The quantification of CDF results from internal flooding events included consideration for operator action to isolate leaks. However, there is no discussion on how HRA was performed on these events. Discussion of operator action is limited to two cases which are said to be typical. The first case addresses the reactor building room 4105 and states that given the cues available to the operator, the operator is expected to isolate the affected system and stop the internal flooding. It is assumed that core spray will be lost and if flooding is in the SACS, the operator isolates that portion of SACS. The submittal is somewhat vague on how the operator action is quantified, but it appears that either a value of 1.0 or 0 was used in the fault tree quantification. In the second case where operator actions is discussed, torus area Room 4102, an HEP of 1.0E-3 was assigned for operator failure to isolate the leak. The value of 1.0E-3 is based on a longer time available to the operators to avoid the failure of the ECCS systems, because the flood water raise slowly in a larger number of rooms.

Operators are alerted to flooding events by annunciators in the control room and procedurally directed response. HEPs were calculated using nominal diagnosis model of NUREG/CR-1278. PSE&G provided an example to demonstrate the process by which these events were assessed. The example given involved the isolation of flooding in RM-4105.

HCGS's treatment of operator action in responding to internal flooding scenarios appears to have been consistent with the guidance of the referenced methodology.

2.3.4.6 Consideration of Operator Actions in the Level 2 Analysis. HCGS performed HRA for containment event tree (CET) basic events associated with operator actions, although the submittal is vague as to the particular methodology applied. Both diagnosis and action events are addressed. The quantification of HEPs is said to have included the following factors:

- The time available for the operator to act,
- The level of stress the operator is under,
- Whether step-by-step procedures are available to guide the operator, and
- Whether technical oversight is provided (e.g., by a senior operator, or by the technical support center (TSC)).

The majority of the HEPs are associated with the failure of the operator to perform the correct action, with very little influence from diagnostic errors. The licensee attributes this to relatively long time frames (typically one hour or more) being available for the operator to act, which we believe is reasonable. The licensee cites the following assumptions for CET quantification:

- All operator actions will be guided by the SRO or TSC (total dependence),
- All operator actions are assumed to have associated procedures for the operator to follow,
- Operators will be under high stress during the back-end (Level 2) portion of the accident.

Operator actions considered in the Level 2 analysis were selected following a detailed review of EOPs and abnormal procedures for adequacy under post-core damage conditions. Quantification of the operator actions selected was performed using the Dougherty and Fragola TRC method (Reference 5). ERIN was consultant to PSE&G for this analysis and their selection of this adjusted correlation to estimate HEPs is reasonable given this method is reported by the author to better address out-of-control-room tasks.

Generally the process includes the following steps:Dougherty and Fragola method.

1) Identify types of human error (omission, commission)
2) Identify PSFs based on similarity with Level 1 operator actions.
3) Develop detailed description.
4) Assign numerical parameters for input to HEP quantification, based on HRA experience.
5) Generate point estimates and percentages.

A total of 28 operator action basic events are reported in IPE Table 4.6-1. In general, HEP values appear to lean toward the conservative side.

2.3.4.7 <u>GSI/USI and CPI Recommendations.</u> The licensee's consideration of generic safety issues (GSIs) and unresolved safety issues (USIs) and of containment performance improvements (CPI) recommendations are the subject of the front-end review, and back-end review, respectively. The HCGS IPE addresses two generic issues, USI A-45 - Decay Heat Removal, and GSI 105 - Intersystem LOCA Outside Containment.

Decay Heat Removal (DHR) - Overall the analysis of DHR reported in submittal Section 3.4.4 appears to be thorough and rigorous in HCGS's consideration of operator actions typically found in other IPEs for similar plants. The licensee credits the closure of Unresolved Safety Issue (USI) A-45 as a result of this analysis. Several recovery actions associated with the loss of DHR were found to contribute significantly (as compared to other human actions considered) to the reduction of CDF, namely these events are discussed in Section 2.4.2.2 of this report.

Interfacing System LOCA Outside of Containment (ISLOCA) - IPE Section 3.1.3.5 contains a discussion of the ISLOCA event trees, Figures 3.1.3-7 through 3.1.2-10. Four operator actions are associated with the event tree top events and these include:

- IS1 early isolation
- X RPV depressurization
- O other makeup sources adequate
- IS2 late isolation

The Interfacing System LOCA (ISLOCA) event trees, Figures 3.1.3-7 through 3.1.2.10, contain human actions for early isolation, RPV depressurization, establishment of other make-up sources, and late isolation. However, there is no mention of early or late isolation in the discussion on HRA, Section 3.3.3. The licensee states in their response to a RAI, that in the case of operator action IS1, (early isolation) of rupture of CS pumps discharge line, the error probability was obtained with order of magnitude estimates instead of a detailed HEP analysis (study performed by ERIN). For operator action IS2 (late isolation) of rupture of CS pumps discharge line, the operator action was assigned a conservative value of 0.5 because of the uncertainty associated with the operation of the valve (harsh environment), and dependency on previous operator errors. The ISLOCA event trees, top event actions and HEPs are listed in Table 2.3-1 below.

IPE Section 3.3.3.5.1 contains a discussion of simulator exercise observations and cites several insights related to leak isolation during LOCA. Specifically, identification of ruptures/leaks from diverse information systems provided to the control room operating personnel and actions to isolate leaks were performed in a consistent and effective manner.

Overall the HCGS's treatment of post-initiator human actions appears reasonably thorough and complete. Results from HCGS's HRA are generally consistent with similar BWR 4 plant reviewed.

Table 2.3-1, ISLOCA Operator Actions

EVENT	IS1 (early isolation of low pressure piping)	X (RPV depressurization)	O (other makeup sources available)	IS2 (late isolation of low pressure piping)
Interface rupture of CS pumps discharge lines	2.1E-3 (rupture) 2.2E-3 (leak)	1.0E-3	1.0E 2 TO 1.0	5.0E-1
Interface rupture of RHR shutdown cooling return line	3.2E-1 (rupture) 4.7E-1 (leak)	1.0E-3	1.0E-2 TO 1.0	5.0E-1
Interface leakage of RHR cooling suction line	1.7E-1	1.0E-3	1.0E-2 TO 1.0	5.0E-1
Interface leakage of RHR pumps discharge lines (LPCI)	4.2E-1	1.0E-3	1.0E-2 TO 1.0	5.0E-1

2.4 Vulnerabilities, Insights and Enhancements

2.4.1 Vulnerabilities.

The HCGS IPE defines vulnerability based on NUREG-1335 screening criteria for reporting systemic sequences. To be considered a vulnerability, those sequences meeting the screening criteria must also contribute inordinately to the CDF with respect to either (1) other sequences or events in the IPE, or (2) in comparison with PRA results for other plants.

In the licensee's analysis, transients involving HVAC failure were determined to contribute inordinately to the CDF. For example, loss of switchgear or 1E panel room cooling had an initial CDF of 3.29E-3/yr. In response to this vulnerability the licensee developed a new procedure for providing alternate methods for panel room cooling. The sequence analysis was repeated and credit was taken for the new procedure which resulted in a reduction of sequence CDF to 9.87E-7/yr. Operator recovery action associated with the new procedure includes taking steps to provide alternative cooling means for electrical equipment in these rooms, i.e., open doors, placement of portable fans, etc,.

2.4.2 IPE Insights Related to Human Performance.

The licensee states (IPE Section 7.1.1.4.2) that sensitivity studies involving adjustment of HEPs upward and downward were not performed for post-accident operator errors because their development was based upon plant-specific data obtained through simulator exercises. However, the licensee performed importance analysis for the highest frequency cutsets and this includes operator action basic events. Although not a sensitivity study, the importance analysis generated results are said to have served as a means to assess which operator actions are most important.

2.4.2.1 Important Operator Actions. In IPE Section 7.1.1.2, the licensee identifies miscalibration events, safety/relief valves (SRVs), DC Buses, reactor protection (scram) and HPCI/RCIC as most important basic events, based on risk increase importance. Whereas, the operator recovery of off-site power, operator recovery of diesel generators, test/maintenance of SSW and SACS loops, failure to depressurize and failure of diesel generators are considered to be most important from a risk reduction viewpoint.

Section 3.4.1.2 and 7.1.1.2 discuss the importance analysis performed by the licensee on 745 highest frequency cutsets, which included 393 basic events and represents 90% of the HCGS IPE results. The results of two measures, *risk reduction* and *risk increase*, are reported in submittal Tables 3.4-4 and 3.4-5 respectively. Risk reduction reflects the improvement (decrease) in the expected CDF achieved by reducing the failure probability of a basic event. Risk increase reflects the degradation (increase) in the expected CDF form arbitrarily failing a basic event. Three out of the top thirty risk-increase events (Table 2.4-1), and twelve out of the top thirty risk-reduction events (Table 2.4-2), are related to operator actions.

Table 2.4-1, Important Operator Actions by Risk Increase Measure

RANK	BASIC EVENT	DESCRIPTION
5	ESF-XHE-MC-DF02	Miscalibration of all level transmitters.
7	ESF-XHE-MC-DFO1	Miscalibration of all pressure transmitters.
11	NR-HVC-PNRM-12	Failure to provide alternate ventilation to the Panel Room within 12 hours after a loss of HVAC.

Table 2.4-2, Important Operator Actions by Risk Reduction Measure

RANK	BASIC EVENT	DESCRIPTION
1	NR-LOSP-6	Failure to restore off-site power within 6 hours.
2	NR-DG-6	Failure to recover EDGs within 6 hours of independent failures of EDGs.
6	NR-DG-DF-6	Failure to recover EDGs within 6 hours of common cause failures of EDGs.
7	ADS-XHE-FO-DEPRE	Operator fails to depressurize.
8	ADS-XHE-OK-INHIB	ADS fails at level I due to INHIBIT by operator.
9	NR-U1X-DEP-60M	Failure to manually depressurize the RPV within 60 minutes.
10	NR-PCS-1	Failure to restore the PCS within 1 hour.
16	SWS-XHE-FO-ISOL	Operator fails to isolate SWS flow diversion.
20	CST-XHE-FO-ALIGN	Operator fails to align condensate storage tank.
23	NR-HVC-PNRM-12	Failure to provide alternate ventilation to the Panel Room within 12 hours after a loss of HVAC.
26	NR-SPL-LLVL-4-03	Failure to align core spray to the CST for long-term injection (without decay heat removal).
28	NR-U1X-DEP-30M	Failure to manually depressurize the RPV with 30 minutes.

The top eleven dominant accident sequences account for 94% of the total CDF with the first five sequences contributing 84.2%. We reviewed these sequences to identify which operator actions were related and compared these with the sensitivity measures, and treatment in HRA to insure consistency. Table 2.4-3, provides a listing of these accident sequences, a brief description of sequence, and the corresponding operator actions which we believe to be relevant to that sequence. The results from this review appear reasonable with no significant deviation in the licensee treatment.

Table 2.4-3, Operator actions related to the top 11 dominant accident sequences (94.0% of the total CDF).

SEQUENCE	% CONTRIBUTION	DESCRIPTION	OPERATOR ACTION(S)
TeEDG	71.4 % CDF=3.27E-5/yr	SBO (LOP with failure of D/Gs), batteries depleted in 4 hours terminating HPCI & RCIC.	Recovery of offsite power (NR-LOSP-n)
TfU1U2X	6.0% CDF=2.76E-6/yr	Total loss of feedwater failure of both HPCI & RCIC, failure to depress.	Operator fails to depressurize the RPV

		the RPV.	
TmUX	2.3% CDF=1.05E-6/yr	MSIV closure, failure of HPCI & RCIC, failure to depress. the RPV.	Operator fails to depressurize the RPV
S1WUv	2.3% CDF=1.04E-6/yr	Medium LOCA, loss of DHR, long-term make-up unsuccessful.	Operator fails to align core spray to the CST for long-term injection. (NR-SPL-LLVL-4-03)
TtQUX	2.3% CDF=1.03E-6/yr	Turbine trip, failure of feedwater, failure of both HPCI & RCIC, failure to depress. the RPV.	Operator fails to depressurize the RPV
S1U1X	2.2% CDF=9.96E-7/yr	Medium LOCA, failure of HPCI, failure to depressurize the RPV.	Operator fails to depressurize the RPV
Thv	2.2% CDF=9.87E-7/yr	Loss of HVAC to either Panel room or Switchgear room, failure to recover HVAC.	Operator fails to provide alternate ventilation to Panel Room within 12 hours of loss of HVAC.
TeEDFP	2.1% CDF=9.67E-7/yr	SBO (same as TeEDG) w/ a stuck open SRV.	(see TeEDG)
TfQRWW1Uv	1.2% CDF=5.30E-7/yr	Total loss of feedwater with failure to recover, failure of containment heat removal, failure of containment venting, failure of long-term make-up.	Operator fails to recover FW, fails to initiate containment venting, fails to provide long-term make-up
TiQUX	1.2% CDF=5.29E-7/yr	Inadvertent opening of a SRV (IORV), failure of FW, HPCI & RCIC, and failure to depress the RPV.	Operator fails to recover FW, fails to depressurize the RPV
TatC2	1.1% CDF=5.07E-7/yr	Turbine trip, failure (mech) control rods to insert, failure of SLC to inject.	Operator fails to inhibit ADS, fails to manually initiate ARI, fails to manually depress the RPV, fails to initiate HPCI, fails to isolate HPCI inj. through core spray, fails to control RPV water level w/ LPCI

In our review of the IPE we look for indications that the licensee has appropriately considered all operator actions which have been found to be important in IPEs for similar plants as well as any actions which may be necessitated because of unique design features. An important input to this element of our review is the insight which the NRC's front-end reviewer (and of lesser degree back-end) offer in the way of identifying which operator actions are important from their perspective. Table 2.4-4 provides a listing of those operator actions deemed to be important to CDF contribution by the front-end reviewer, the fault/event tree identifier, and the HEP assessed.

Twenty-eight human actions were included in the Level 2 analysis, see Section 2.3.4.6 of this report. Other than the generalization that all operator actions are considered important in the Level 2 analysis, specific significant human actions were not identified.

Table 2.4-4, HCGS Operator Actions Identified as Important by Front-end Reviewer

OPERATOR ACTION	HRA IDENTIFIER	HEP
Manual initiation of depressurization	NR-U1X-DEP-60M NR-U1X-DEP-30M (ADS-SHE-FO-DEPRE)	4.6E-3 7.5E-3
Providing alternate ventilation for electrical areas	NR-HVC-PNRM-12 (HVAC-XHE-FO-RECY)	3.0E-4
Inhibition of ADS during ATWS sequences	NR-ATWS-ADS-INH (ADS-XHE-ATWS-INH) (ADS-XHE-OK-INHIB)	7.5E-2
Manual initiation of SP cooling	(RHS-XHE-FO-SPC) Screened out	N/A
Inhibition of HPCI injection via core spray following an ATWS	NR-ATWS-HPCI-CS (ATW-XHE-HP-CS-IN)	2.4E-1
Using alternate SACS loop for DG cooling (cross-tie)	Dropped following detailed evaluation	N/A
Implementation of alternate injection for core cooling	NR-SPL-LLVL-4-03 (UV1-XHE-FO-ALIGN) (CST-XHE-FO-ALIGN)	1.1E-1
Isolation of a seal LOCA	NR-SLEAK-ISO-15M (XHE-FO-SEAL-ISOL)	8.2E-2
Isolation of internal floods within 30 minutes	IS1	4.7E-01 to 2.1E-03 depending on location

2.4.2.2 Sequences Screened Out By Low HEPs. Sequences which would have been above the cutoff criteria were it not for low human error probabilities in recovery actions are discussed in the submittal. This aspect of the licensee's analysis is well documented with detail discussion consistent with what is requested in NUREG-1335.

Appendix A attached to this TER report, lists in table format the 30 sequences screened out by low HEPs. The exhibit table is structured to provide the sequence identifier, sequence description, human recovery actions applicable, and a description of those actions in order to better facilitate identification of the type of accidents involved. It is of interest to note that the predominant accident sequences appearing in the 9 top events (those just below the cut-off) are associated with loss of DHR. Additionally, Table 3.4-6 of the submittal reports a substantial change in certain accident sequences contribution to CDF due to recovery actions applied (e.g., TtQWW1Uv from 2.08E+00 to 1.4E-08 and TmWW1Uv from 1.43E-01 to <1E-10). Also notable, is that a number of the specific actions associated with the sequences screened are outlier events in the non-conservative direction, namely; 1) NR-PCS-

24, failure to restore the PCS within 24 hrs following a turbine trip or MSIV closure initiating event (7.0E-04), 2) NR-RHR-INIT, failure to initiate RHR for decay heat removal within 24 hrs (5.0E-05), and 3) NR-WW1-SWP-20, failure to manually start SSWS or SACS pumps within 20 hours (7.4E-05). In response to a NRC RAI, the licensee provided the detailed "Tier 2" analysis for events NR-RHR-INIT and NR-WW1-SWP-20. We reviewed these assessments and found the analysis process to be reasonably thorough, complete and consistent with the methodology applied. In the case of event NR-PCS-24, a HEP was not calculated in the same manner as the others but was taken from NUREG/CR-4550.

2.4.3 Enhancements and Commitments.

During the IPE effort a significant impact on CDF was identified where HVAC is lost for electrical equipment rooms. A procedure was developed, and credited in the analysis, for providing alternate cooling to key electrical equipment rooms. As a result of procedural recovery of partial cooling CDF was lowered from 3.29E-3/yr to 9.8E-7/yr.

Additionally, the licensee initiated a detailed review of the success criteria for SSW and SACS to see if some of the conservatism presently in the model could be relaxed by crediting additional operator action. A new procedure for operating SACS with one pump per loop was thought to result in a substantial improvement in CDF resulting from SBO. The licensee reports in their response to NRC's request for additional information that after detailed evaluation it was determined that little benefit was to be derived by taking credit for this operator action.

3. CONTRACTOR OBSERVATIONS AND CONCLUSIONS

The purpose of our document-only review is to enhance the NRC staff's ability to determine with the licensee's IPE met the intent of Generic Letter 88-20. The Generic Letter had four specific objectives for the licensee:

(1) Develop an appreciation of severe accident behavior.

(2) Understand the most likely severe accident sequences that could occur at its plant.

(3) Gain a more quantitative understanding of the overall probability of core damage and radioactive material releases.

(4) If necessary, reduce the overall probability of core damage and radioactive material release by appropriate modifications to procedures and hardware that would prevent or mitigate severe accidents.

With specific regard to the HRA, these objectives might be restated as follows:

(1) Develop an overall appreciation of human performance in severe accidents; how human actions can impact positively or negatively the course of severe accidents, and what factors influence human performance.

(2) Identify and understand the operator actions important to the most likely accident sequences and the impact of operator action in those sequences; understand how human actions affect or help determine which sequences are important.

(3) Gain a more quantitative understanding of the quantitative impact of human performance on the overall probability of core damage and radioactive material release.

(4) Identify potential vulnerabilities and enhancements, and if necessary/appropriate, implement reasonable human-performance-related enhancements.

The following observations from our document-only review are seen as pertinent to NRC's determination of the adequacy of the HCGS submittal:

1) The submittal and supporting documentation indicates that utility personnel were involved in the HRA, and that the walkdowns and documentation reviews constituted a viable process for confirming that the HRA portions of the IPE represent the as-built, as-operated plant.

2) The licensee performed an in-house peer review that provides some assurance that the HRA techniques have been correctly applied and that documentation is accurate.

3) The licensee's analysis of pre-initiator human actions was reasonably complete, though simplified and relatively generic. Identification and selection of human actions to be quantified included review of calibration, test and maintenance procedures and discussion with plant personnel. Both calibration and restoration errors were included. No numerical screening was performed; qualitative screening that appears to be rational and consistent with other PRAs eliminated some actions from consideration. All actions surviving the qualitative screening were included in the IPE model as basic events in fault trees. The quantification used THERP to analyze four "generic" pre-initiator actions that represented all pre-initiator actions included in the model. Plant-specific and certainly case-specific analysis was very limited. This limits the ability of the licensee to identify factors contributing to human error and therefore plant risk and to identify possible enhancements. However, the analysis appears to have been effective in identifying the relative importance of contributions from pre-initiator human errors.

4) The treatment of post-initiator human actions included both response-type and recovery-type actions. The process for identification and selection of post-initiator human actions included review of procedures and discussion with plant operations and training staff. Numerical screening based on guidance in NUREG/CR-4772 was employed to eliminate actions or sequences from further consideration. Quantification of human error used the ASEP and EPRI NP-6560-L processes for detailed calculations. The guidance for methodologies used appears to have been followed by the licensee. Evaluation of plant-specific performance shaping factors was included, consistent with the simplified ASEP process; and, error recovery factors were included according to ASEP guidance. Dependencies among post-initiator actions were treated in a manner consistent with the ASEP dependency model.

5) The process used by the licensee to obtain plant-specific data for representation of performance shaping factors, namely simulator exercises, procedure walkdowns and discussion with key plant personnel, is considered a strength in their HRA.

6) The licensee employed a systematic process to screen for vulnerabilities and identify potential enhancements. Vulnerability screening criteria included NUREG-1335 reporting criteria plus a comparison with other PRA results to identify unusual contributors. In the licensee's analysis, transients involving HVAC failure were determined to contribute inordinately to the CDF. For example, loss of switchgear or 1E panel room cooling had an initial CDF of 3.29E-3/yr. In response to this vulnerability the licensee developed a new procedure for providing alternate methods for panel room cooling. The sequence analysis was repeated and credit was taken for the new procedure which resulted in a reduction of sequence CDF to 9.87E-7/yr. Operator recovery action associated with the new procedure includes taking steps to

provide alternative cooling means for electrical equipment in these rooms, i.e., open doors, placement of portable fans, etc,.

7) A total of 28 operator action basic events are reported in IPE Table 4.6-1, back-end analysis. HRA appear to have been appropriately performed using the Dougherty and Fragola TRC methodology.

4. DATA SUMMARY SHEETS

Important Operator Actions/Errors:

Pre-Initiator Errors:

Miscalibration of all level transmitters.
Miscalibration of all pressure transmitters.

Post-Initiator Errors:

Failure to restore off-site power within 6 hours.
Failure to recover EDGs within 6 hours of independent failures of EDGs.
Failure to recover EDGs within 6 hours of common cause failures of EDGs.
Operator fails to depressurize.
ADS fails at level I due to INHIBIT by operator.
Failure to manually depressurize the RPV within 60 minutes.
Failure to restore the PCS within 1 hour.
Operator fails to isolate SWS flow diversion.
Operator fails to align condensate storage tank.
Failure to provide alternate ventilation to the Panel Room within 12 hours after a loss of HVAC.
Failure to align core spray to the CST for long-term injection (without decay heat removal).
Failure to manually depressurize the RPV with 30 minutes.

Human-Performance Related Enhancements:

- **Enhanced Procedures and Operator Actions:**
  Alternate cooling methods during loss of HVAC to key electrical equipment rooms resulted in a decrease in CDF from 3.29E-3/yr to 9.8E-7/yr. Procedurally directed actions to facilitate alternate cooling methods on loss of HVAC to electrical equipment rooms has a significant impact for reducing CDF.

- **Potential Operational Improvement Under Consideration and Not Modeled:**
  Procedure enhancements related to SSW and SACS could have a substantial influence on the reduction of CDF in SBO. A new procedure for operating SACS with one pump per loop could result in a substantial improvement in CDF resulting from SBO. Subsequent to the submission of the IPE, the licensee determined little benefit was to be derived from this action, and dropped it from further consideration.

REFERENCES

1) Systematic Human Action Reliability Procedure (SHARP), EPRI NP-3583.

2) Handbook of Human Reliability Analysis With Emphasis on Nuclear Power Plant Operations, NUREG/CR-1278

3) Accident Sequence Evaluation Program Human Reliability Analysis Procedure (ASEP), NUREG/CR-4772.

4) A Human Reliability Analysis Approach Using Measurements For Individual Plant Examinations, EPRI NP-6560L.

5) E.M. Dougherty and J.R. Fragola, Human Reliability Analysis: A System Engineering Approach With Nuclear Power Applications. New York: John Wiley Interscience, 1988.

Appendix A

30 Sequences Identified As Being Screened Out by Recovery Actions

SEQUENCE DESCRIPTION	SEQUENCE DESCRIPTION	RECOVERY ACTION	RECOVERY
TtQWW1Uv TmWW1Uv	Loss of DHR	NR-PCS-24	Failure to restore PCS within 24hrs.
		NR-RHR-INIT	Fail to initiate RHR within 24 hrs.
		NR-WW1-SWP-20	Failure to manual start SSWS or SCAS pumps within 20 hrs.
		NR-VENT-5	Fail to initiate contnmnt venting
TeWW1uV	LOP w/ loss of DHR	NR-LOSP-24	Failure to restore offsite power within 24 hrs.
		NR-RHR-INIT	Failure to initiate RHR within 24 hrs.
		NR-VENT-5	Fail to initiate contnmnt venting
TmPP2WUv	MSIV closure w/ 2 SORVs stuck open and loss of DHR	NR-PCS-24	Fail to restore PCS within 24hrs
		NR-RHR-INIT	Failure to initiate RHR within 24 hrs.
		NR-WW1-SWP-20	Failure to manual start SSWS or SCAS pumps within 20 hrs.
S1WW1Uv	Medium LOCA and loss of DHR	NR-RHR-INIT	Failure to initiate RHR within 24 hrs.
		NR-VENT-5	Fail to initiate contnmnt venting
TtPP2WW1Uv	Turbine trip with 2 SORVs and loss of DHR	NR-RHR-INIT	Failure to initiate RHR within 24 hrs.
		NR-WW1-SWP-20	Failure to manual start SSWS or SCAS pumps within 20 hrs.
		NR-VENT-5	Fail to initiate contnmnt venting
AWW1Uv	Large LOCA with loss of DHR	NR-RHR-INIT	Failure to initiate RHR within 24 hrs.
		NR-VENT-5	Fail to initiate contnmnt venting
TmPP2WW1Uv	MSIV closure w/ 2 SORVs stuck open, loss of DHR and failure to vent containment	NR-PCS-24	Fail to restore PCS within 24hrs
		NR-WW1-SWP-20	Failure to manual start SSWS or SCAS pumps within 20 hrs.
		NR-RHR-INIT	Failure to initiate RHR within 24 hrs.
		NR-VENT-5	Fail to initiate contnmnt venting
TiaWW1Uv	Loss of instrument air and loss of DHR	NR-RHR-INIT	Failure to initiate RHR within 24 hrs.
		NR-WW1-SWP-20	Fail to manual start SSWS or SCAS pumps within 20 hrs.

		NR-VENT-5	Fail to initiate contnmnt venting
S2S3IsoQUX	Recirc pump seal LOCA, loss of FW, loss of HPCI & RCIC, and failure to depressurize	NR-SLEAK-ISO-15M	Failure to isolate recirculation pump seal LOCA
		NR-U1X-DEP-40M	Failure to manually depress the RPV within 40 minutes.
ThvP	Loss of HVAC with SORV	NR-HVC-PNRM-12	Failure to provide alternate ventilation to the panel room within 12 hrs after loss of HVAC.
TtPQUX	Turbine trip with SORV, loss of FW, loss of HPCI & RCIC, and failure to depressurize	NR-PCS-40M	Failure to restore PCS within 40 minutes.
		NR-U1X-DEP-40M	Fail to manually the depress the RPV within 40 minutes.
		NR-Q-FWLVH-4M	Failure to prevent a level 8 trip of feedwater during a transient.
TraPP2WUv	Loss of RACS w/ 2 SORVs, loss of DHR	NR-WW1-SWP-20	Failure to manual start SSWS or SCAS pumps within 20 hrs.
		NR-RHR-INIT	Failure to initiate RHR within 24 hrs.
		NR-VENT-5	Fail to initiate contnmnt venting
TfU1U2UV	Loss of FW w/ failure of all injection to RPV	NR-UV-WTLVL-20M	Failure to control RPV water level w/ high pressure injection systems (non-ATWS).
		NR-UV-ECCS-1	Failure to manually initiate ECCS within 1hr.
TeUX	LOP w/ failure of HPCI & RCIC, failure to depress.	NR-LOSP-60M	Failure to restore offsite power within 1 hr.
		NR-U1X-DEP-60M	Failure to manually depress the PRV within 1 hr
S2QUX	Small LOCA, failure of FW, HPCI & RCIC, fail to depress.	NR-U1X-DEP-40M	Failure to manually depressurize the RPV within 40 minutes.
		NR-Q-FWLVL-24M	Failure to prevent a level 8 trip of feedwater during a small LOCA.
TraQUX	Loss of RACS, failure of FW, HPCI & RCIC, fail to depress.	NR-U1X-DEP-60M	Failure to manually depress the RPV within 1 hr.
		NR-Q-FWLVH-4M	Failure to prevent a level 8 trip of feedwater during a transient.
		NR-WW1-SWP-1	Failure to manually start SSWS or SACS pumps within 1 hr.
TmUV	MSIV closure w/ failure of all injection to RPV.	NR-PCS-1	Failure to restore PCS within 1 hr.

		NR-UV-ECCS-1	Failure to manually initiate ECCS within 1hr.
		NR-UV-WTLVL-20M	Failure to control RPV water level with high pressure injection systems (non-ATWS).
TfPU1U2X	Loss of FW w/ a SORV, failure of HPCI & RCIC, fail to depress RPV.	NR-U1X-DEP-40M	Failure to manually depressurize the RPV within 40 minutes.
S1U1WW1Uv	Medium LOCA, failure of HPCI, loss of DHR.	NR-RHR-INIT	Failure to initiate RHR within 24 hrs.
		NR-VENT-5	Failure to initiate containment venting.
TePWW1Uv	LOP w/ a SORV, loss of DHR.	NR-LOSP-24	Failure to restore offsite power within 24 hrs.
		NR-RHR-INIT	Failure to initiate RHR within 24 hrs.
		NR-VENT-5	Failure to initiate containment venting.
TmPUX	MSIV-closure w/ a SORV, failure of HPCI, fail to depress RPV.	NR-U1X-DEP-40M	Failure to manually depressurize the RPV within 40 minutes.
TatQUIX	MSIV-closure, ATWS (mech), failure HPCI, FW, fail to depress RPV.	NR-ATWS-HPCI	Failure to initiate HPCI during ATWS.
		NR-ATWS-DEP	Failure to manually depressurize the PRV during ATWS.
TraPP2WW1Uv	Loss of RACS w/ 2 SORVs, loss of DHR.	NR-WW1-SWP-20	Failure to manually start SSWS or SACS pumps within 20 hrs.
		NR-RHR-INIT	Failure to initiate RHR within 24 hrs.
		NR-VENT-5	Failure to initiate containment venting.
TiaPP2WUv	Loss of IAS w/ 2 SORVs, loss of DHR.	NR-WW1-SWP-20	Failure to manually start SSWS or SACS pumps within 20 hrs.
		NR-SPL-LVLL-4	Failure to align core spray to the CST for long-term injection (w/o DHR).
ThvPP2	Loss of HVAC w/ 2 SORVs.	NR-HVC-PNRM-12	Failure to provide alternate ventilation to the Panel Room within 12 hrs after loss of HVAC.
ThvU	Loss of HVAC, failure of HPCI & RCIC.	NR-HVC-PNRM-12	Failure to provide alternate ventilation to the Pump Room within 12 hrs after loss of HVAC.
TiQUV	Inadvertent opening of SRV, failure of FW and all other injection to the RPV.	NR-UV-WTLVL-20M	Failure to control RPV water level with high pressure injection systems (non-ATWS).

		NR-UV-ECCS-40M	Failure to manually initiate ECCS within 40 minutes.
TeEDGU	SBO, failure of HPCI & RCIC.	NR-LOSP-1	Failure to restore offsite power within 1 hr.
		NR-UV-ECCS-1	Failure to manually initiate ECCS within 1hr.
		NR-UV-WTLVL-20M	Failure to control RPV water level with high pressure injection systems (non-ATWS).
TtQWUv	Turbine trip, failure of FW, loww of DHR.	NR-PCS-24	Failure to restore PCS within 24 hrs.