UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Licensee: Florida Power Corporation
3201 34th Street, South
St. Petersburg, FL 33733

Docket No.: 50-302 License No.: DPR-72

Facility Name: Crystal River 3

Inspection Conducted: March 28-April 8, 1988

Inspection Team Leader: C. Julian for 6/6/88
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C. A. Julian, Chief Date Signed
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SUMMARY

Scope: This special, announced inspection was conducted in the area of review of the adequacy of Emergency Operation Procedures.

Results: Although numerous technical and human factors deficiencies were identified, the Emergency Operating Procedures were found to be adequate for continued operation of the facility. The licensee committed to review the deficiencies and take prompt corrective action to resolve them. No violations or deviations were identified.

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   *D. deMontfort, Nuclear Operations Engineer
   *D. Green, Licensing Specialist
   *D. Harper, Regulatory Specialist
   *V. Hernandez, Supervisor, QA Surveillance
   *B. Hickle, Manager, Nuclear Plant Operations and Maintenance
   *L. Moffatt, Nuclear Safety Supervisor
   *E. Renfro, Director, Nuclear Ops. Matl. & Contr.
   *W. Rossfeld, Manager, Nuclear Compliance
   *K. Vogel, Nuclear Operations Engineer
   *W. Wilgus, Vice President, Nuclear Operations
   *R. Wittman, Nuclear Operations Superintendent

   Other licensee employees contacted included engineers, technicians, operators and office personnel.

   NRR Attendees

   *W. Regan, Chief Human Factors Assessment Branch, NRR
   *H. Silver, Project Manager, NRR

   NRC Resident Inspector

   *T. Stetka, Senior Resident Inspector
   *J. Tedrow, Resident Inspector

   *Attended exit interview on April 8, 1988.

2. Exit Interview

   The inspection scope and findings were summarized on April 8, 1988, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection findings listed below. Although proprietary material was reviewed during this inspection, no proprietary material is contained in this report. No dissenting comments were received from the licensee.

   Note: A list of abbreviations used in this report is contained in Appendix E.

Item Number	Status	Description/Reference Paragraph
IFI 302/88-09-01	Open	Resolution of placekeeping deficiencies (paragraph 5).

IFI 302/88-09-02	Open	Licensee's implementation of an EOP cross reference document (paragraph 5).
IFI 302/88-09-03	Open	Correction of technical discrepancies contained in EOPs as outlined in Appendix B.
IFI 302/88-09-04	Open	Correction of human factors discrepancies contained in EOPs as outlined in Appendix C.
IFI 302/88-09-05	Open	Correction of labeling discrepancies between EOPs and panel indications as outlined in Appendix D.
IFI 302/88-09-06	Open	Licensee needs to re-perform EOP table top review and procedure walk-throughs to upgrade the V&V program (paragraph 6).
IFI 302/88-09-07	Open	Licensee will review SOTA training and upgrade if necessary (paragraph 6).
IFI 302/88-09-08	Open	Licensee needs to formalize the program for ongoing evaluation of EOPs (paragraph 8).
IFI 302/88-09-09	Open	Re-validation of the EOPs when the plant specific simulator is operational (paragraph 8).

3. Background Information

Following the Three Mile Island (TMI) accident, the Office of Nuclear Reactor Regulation developed the "TMI Action Plan" (NUREG-0660 and NUREG-0737) which required licensees of operating reactors to reanalyze transients and accidents and to upgrade emergency operating procedures (EOPs) (Item I.C.1). The plan also required the NRC staff to develop a long-term plan that integrated and expanded efforts in the writing, reviewing, and monitoring of plant procedures (Item I.C.9). NUREG-0899, "Guidelines for the Preparation of Emergency Operating Procedures," represents the NRC staff's long-term program for upgrading EOPs, and describes the use of a "Procedures Generation Package" (PGP) to prepare EOPs. The licensees formed four vendor type owner groups corresponding to the four major reactor types in the United States; Westinghouse, General Electric, Babcock & Wilcox, and Combustion Engineering. Working with the vendor company and the NRC, these owner groups developed Generic Technical Guidelines (GTGs) which are generic procedures that set forth the desired accident mitigation strategy. These GTGs were to be used by the licensee in developing their PGPs. Submittal of the PGP was made a requirement by Confirmatory Order dated February 21, 1984. Generic Letter 82-33, "Supplement 1 to NUREG-0737 - Requirements for Emergency Response Capability" requires each licensee to submit to the NRC a PGP which includes:

(i) Plant-specific technical guidelines with justification for differences from the GTG

(ii) A writer's guide

(iii) A description of the program to be used for the validation and verification of EOPs

(iv) A description of the training program for the upgraded EOPs.

From this PGP, plant specific EOPs were to have been developed that would provide the operator with directions to mitigate the consequences of a broad range of accidents and multiple equipment failures.

Due to various circumstances, there were long delays in achieving NRC approval of many of the PGPs. Nevertheless, the licensees have all implemented their EOPs. To determine the success of the implementation, a series of NRC inspections are being performed to examine the final product of the program; the EOPs. The objective is to perform table top reviews, simulator exercises where possible, and in-plant walk-throughs of the EOPs with licensed operators to verify their adequacy. The EOPs are considered to be adequate for use if they can be understood and performed successfully by the operators and they incorporate the accident mitigation strategy developed by the appropriate vendor specific owner group.

This inspection report represents findings, observations, and conclusions regarding the adequacy of the EOPs. It did not, as a matter of intent, review whether the EOPs thus prepared conformed to the NRC staff's long-term program for upgrading EOPs and whether those EOPs had been properly prepared using a PGP.

The success level of licensees in following the PGP submitted to NRC is a regulatory issue that will be dealt with on a case-by-case basis. Although some licensee's EOPs strayed far from their PGP, that issue is of secondary importance to this inspection effort. The purpose of this inspection is to verify adequacy of the EOPs for continued safe operation of the facility.

4. EOP/GTG Comparison

The inspectors performed a comparison of the Crystal River EOPs against the Crystal River ATOG. From this comparison the inspectors determined that a significant change in procedural organization occurred between the Crystal River ATOG and the Crystal River EOPs. For example, the Crystal River ATOG contains the following major responses to a reactor trip or to the conditions which should have resulted in a reactor trip:

III A Lack of Adequate Subcooling Margin
III B Lack of Heat Transfer
III C Excessive Heat Transfer
III D Steam Generator Tube Rupture

The licensee has not developed specific procedures corresponding to the first three major responses listed above. However, the licensee has incorporated the major actions of these responses into other Crystal River EOPs. For example, comparable material can be found in procedures such as AP-580, Reactor Trip, and AP-380, Engineered Safeguards Actuation.

The Oconee ATOG was submitted to the NRC by the B&W Owner's Group as the B&W generic model for the development of EOPs. The licensee has in place documentation to support the development of the Crystal River ATOG from the approved Oconee ATOG. However, there is no documentation describing the development of the Crystal River EOPs from the Crystal River ATOG. Based on the results of this inspection NRC observes that the basic elements of the Oconee ATOG have been incorporated in the EOPs.

There were no violations or deviations noted in this area.

5. Technical Adequacy Review of the EOPs

The inspectors determined by review of the procedures listed in Appendix A that generally the vendor recommended step sequence is followed, even though this is not immediately evident when examining the EOPs. Review of the procedures has established that the ATOG guidance is contained within each of the EOPs as applicable. The general priority of treatment and order of steps are maintained at the expense of additional bulk in the procedures.

Placekeeping deficiencies were identified during control room walk-throughs of the EOPs. Operators typically use loose sheets of paper or their fingers as placekeeping aids. Additionally, when questioned on the problem of placekeeping, the operators indicated that they would remove the individual procedures from the notebooks and place them on the desk. This is undesirable, particularly when one considers that the EOPs are not stapled and can easily become intermixed, separated, or lost. This is an indication of a placekeeping deficiency. The licensee has committed to resolve these placekeeping deficiencies. Resolution of this issue will be identified as IFI 302/88-09-01.

The inspectors verified that entry conditions into the procedures were clearly identified and could be easily followed by operations personnel. The scenarios postulated during the procedure walk-throughs resulted in multiple transfers and cases of simultaneous use of several different AOPs and EOPs. Although this is a complicated method of operation, no examples of significant performance error were identified. The licensee's use of notes and cautions within the EOPs is generally clear, appropriate, and placed in the correct location. The inspectors verified that the priority of accident mitigation appears to be maintained in the licensee's EOPs even though the organization is quite different from the ATOG.

The licensee has not developed documentation to identify major deviations between the Crystal River EOPs and the ATOG. No review was performed to ensure that any identified deviations have adequate technical justification nor could it be determined that any safety significant deviations were documented.

Currently, the licensee has no document in place to cross reference operator action points for plant parameters to where they occur in procedures. The licensee has committed to implement an EOP cross reference document. Resolution of this issue will be identified as IFI 302/88-09-02.

There were no violations or deviations noted in this area.

6. Review of the EOPs by In-Plant and Control Room Walk-throughs

In-plant and control room walk-throughs of the emergency, abnormal and verification procedures listed in Appendix A were conducted to ensure that:

° Procedural guidance is clear enough that operator confusion and/or error can be avoided.

° Actions required by the procedures, either locally or in the control room, can be accomplished using existing available equipment, instrumentation and controls.

There are two sets of emergency and abnormal procedures maintained in the control room at all times. These procedures were verified to be of the latest revision and free of any handwritten changes.

As a result of these walk-throughs no violations or deviations were identified. However, many discrepancies in the areas of technical content, writer's guide adherence and human factors were noted. Technical discrepancies are identified in Appendix B, while writer's guide and human factors discrepancies are noted in Appendix C. The licensee has committed to correct the discrepancies identified in the aforementioned appendices. Appendix B discrepancies will be identified as IFI 302/88-09-03 and Appendix C discrepancies will be identified as IFI 302/88-09-04.

Generally, there are a large number of inconsistencies (listed in Appendix D) between the instrumentation and control labeling on the control board and the nomenclature used in the procedures. The licensee has committed to perform a complete nomenclature review as part of the current work in progress to change control board labeling. Appendix D discrepancies will be identified as IFI 302/88-09-05.

Most of the problems identified by the NRC are inconsistencies between equipment label designation and the nomenclature used within the procedures. There were also minor problems in sequencing of steps and discrepancies with the Writer's Guide. While individually, most of the specific problems were relatively minor, the large number of these problems indicates that EOP verification has not been adequately completed. This finding of the NRC was supported by operator interviews. All the operators agreed that while the procedures were basically sound, there were still many minor flaws.

These problems appear to be due to deficiencies in the validation and verification (V&V) program. While the Crystal River V&V program appropriately consisted of table-top reviews, control room walk-throughs, and scenario based simulations using the B&W simulator, the control room walk-throughs were largely performed by the author of most of the procedures. This is a departure from good V&V practice, which calls for V&V activities to be performed by different personnel, preferably working for different management. The extensive familiarity of the author with his work makes it difficult for him to identify the types of discrepancies uncovered in this inspection. The licensee needs to repeat the table-top and control room walk-throughs using different personnel. These personnel should be familiar with the Writer's Guide and generally familiar with plant design. However, they need not be licensed operators, whose expertise might prevent them from identifying these types of problems. The licensee has committed to re-perform the table-top reviews and procedure walk-throughs. Resolution of this issue will be identified as IFI 302/88-09-06.

The scenario postulated by the NRC during the walk-throughs of AP-380 required local operator action to establish long term heat removal with DHR. Under the scenario used, following a massive core damage accident, the reactor coolant would be highly contaminated. If this coolant were circulating in the MU lines, the resultant high radiation levels in the auxiliary building may prohibit access to the locked breaker for valve DHV-3 at the 95 ft elevation. This breaker must be actuated to open the DHR drop line and permit operation in the DHR mode. This problem can be eliminated if procedural guidance directs the operators to close the breaker for the valve prior to changeover from the BWST suction to the RB sump. The licensee committed to make this procedure change. This was the only deficiency of this type found during the inspection. The licensee should postulate and review additional examples of core damage accidents to determine if required local actions can be performed.

There was a strong indication that certain Shift Operation Technical Advisors (SOTAs) lacked sufficient training to adequately perform their function. Two out of four SOTAs, who demonstrated the use of VP-540 and VP-580 during walk-throughs, exhibited an unfamiliarity with the procedure. Some SOTAs made incorrect assessments of the proposed symptoms and were unaware of various plant instrument indications. Examples of this include not knowing that computer group 59 indicated the current plant heat balance, not knowing that the indicated RCS code safety valve position was by acoustical means vice tailpipe temperature measurement, lack of knowledge concerning the emergency bus configuration (i.e., control board ES breaker alignment) and not being able to calculate subcooling margin.

The licensee committed to promptly review the training of the SOTAs and upgrade it if found necessary. This matter will be reviewed during a future inspection (IFI 302/88-09-07).

There were no violations or deviations noted in this area.

7. EOP User Interviews

Ten interviews were conducted by the NRC inspection team. The personnel interviewed consisted of four Nuclear Operators (three Reactor Operators and one Senior Reactor Operator), one Assistant Nuclear Shift Supervisor, two Nuclear Shift Supervisors, two Operations Technical Advisors, and one Chief Nuclear Operator. The purpose of these interviews was to determine if the current EOPs satisfy the needs of the operational personnel. Personnel were questioned on the adequacy of the EOPs in the following areas:

- Adequate staffing levels for performance of the EOPs.
- Problems in physically using the EOPs from personal experience or observation, or from discussions with others.
- Knowledge of technical discrepancies.
- Adequacy of training on EOPs.

The results of these interviews can be summarized as follows:

- The operators felt the level of detail contained in the EOPs is adequate and compatible with their level of knowledge.
- The operators felt the EOPs are relatively easy to use.
- Placekeeping aids are felt to be sufficient to allow the use of several procedures simultaneously. (Note: This opinion expressed by the operators was not substantiated during the actual walk-throughs where difficulty was encountered in place keeping between several procedures.)
- Communications during use of EOPs both within the control room and with other areas of the plant are adequate.
- Operators felt there is adequate staffing to perform the EOPs.
- Operators felt the current EOPs represented a significant improvement over previous versions.

- Almost all people interviewed incorrectly believed the words "ensure" and "verify," to have the same meaning contrary to the Writer's Guide. Additionally, the operators did not understand that a conditional statement preceded by WHEN is to be considered a holding point, unless otherwise stipulated with a continue statement. These inconsistencies indicate a need for further operator training in the conventions and definitions contained in the Writer's Guide.

- The operators felt that current procedures are free of major technical errors, but that they do contain a fairly large number of small discrepancies which need to be corrected.

- They felt that inconsistencies in nomenclature between the procedures and equipment designation are common. However, they stated that the EOP nomenclature is consistent with operator usage. During walk-throughs no operator confusion was observed as a result of these inconsistencies.

In conclusion, the operations staff was confident that the EOPs would function effectively during an actual event.

There were no violations or deviations noted in this area.

8. Ongoing Evaluation of the EOPs

Administrative controls were reviewed to determine if the licensee has an acceptable program in place for a continuing evaluation of EOPs. The licensee's controls on revising procedures based on changes to plant equipment, operator feedback for improvement, and revisions to the vendor GTGs were reviewed.

The original EOPs were reviewed in accordance with the licensee's V&V program that is detailed in their EOP Writer's Guide. Other than the two year periodic review of procedures that is required by the STS and implemented by procedure AI-400, the licensee has no formal (i.e., covered by a procedure) program for continuing evaluation of EOPs. The two year periodic review program is essentially a "paper" review of the procedures and does not require a re-validation of the procedures by the use of walk-throughs or use on a simulator. The licensee does have informal methods for feedback to the EOPs. These methods include:

- When operator training either on the simulator or during plant walk-throughs is conducted and discrepancies are identified, these discrepancies are fed back to the appropriate section for procedure correction.

- During analysis of a plant event, if discrepancies with the EOPs are identified, the discrepancies are fed back to the appropriate section for procedure correction.

The licensee has recently issued a new procedure AI-402A, Writer's Guide for Abnormal, Verification, and Emergency Operating Procedures, which encompasses the original Writer's Guide. This procedure requires a procedure validation to be performed (which is the licensee's V&V program) for any initial procedure issued but does not provide for an on-going review. To provide for an on-going EOP evaluation, the licensee has committed to develop a formal evaluation program (possibly in AI-402A). In addition, when the licensee's plant specific simulator becomes operational (presently scheduled for September 1989), the licensee has committed to re-validate the EOPs on this simulator. Resolution of these commitments will be identified as IFIs 302/88-09-08 and 302/88-09-09, respectively.

9. Writer's Guide For OPs

The plant staff has initiated and developed a Writer's Guide for station operating procedures. This Writer's Guide was reviewed. Lack of such a document has been a human factors concern at nearly all plants due to the format discontinuity between EOPs and referenced OPs. Development of this document and further improvement as suggested below should add to the efficiency of EOP usage by maintaining the formats of the OPs and EOPs very similar.

However, many format differences are allowed by the Writer's Guide for the OPs and EOPs. Some differences are required due to the different uses of these procedures, but they should be as consistent as possible. For example, notes and cautions are formatted differently according to the two Writer's Guides. This could result in a negative transfer of training with the OPs degrading performance of the EOPs. The licensee acknowledged the inspector's comments and agreed to consider the matter.

APPENDIX A

LIST OF EMERGENCY OPERATING PROCEDURES

EOP	TITLE
AP-250	Radiation Monitor Actuation, Revision 0
AP-330	Loss of Nuclear Services Water, Revision 3
AP-360	Loss of Decay Heat Removal, Revision 1
AP-380	Engineered Safeguards Actuation, Revision 8
AP-450	Emergency Feedwater Actuation, Revision 10
AP-460	Steam Generator Isolation Actuation, Revision 5
AP-513	Toxic Gas, Revision 4
AP-525	Continuous Control Rod Motion, Revision 0
AP-530	Natural Circulation, Revision 6
AP-545	Plant Runback, Revision 0
AP-580	Reactor Trip, Revision 8
AP-660	Turbine Trip, Revision 4
AP-770	Emergency Diesel Generator Actuation, Revision 8
AP-961	Earthquake, Revision 2
AP-990	Shutdown from Outside Control Room, Revision 2
AP-1075	Violent Weather, Revision 9
EP-140	Emergency Reactivity Control, Revision 4
EP-220	Pressurized Thermal Shock, Revision 3
EP-290	Inadequate Core Cooling, Revision 6
EP-390	Steam Generator Tube Leak, Revision 5
VP-540	Runback Verification Procedure, Revision 1
VP-580	Plant Safety Verification Procedure, Revision 8

APPENDIX B

TECHNICAL COMMENTS

This appendix contains technical comments, observations and suggestions for EOP improvements made by the NRC inspectors. Unless specifically stated, these comments are not regulatory requirements. The licensee agreed to evaluate the comments and take appropriate action. These items will be reviewed during a future NRC inspection.

1. AP-360, Loss of Decay Heat Removal, Revision 1

   a. Step 3.2; Containment integrity should be established under any condition that involves the potential for a significant release of radioactive material from the fuel and not just for the leak into the RB.

   b. Step 3.3; The licensee should consider isolation of the RCS, if a leak is determined to exist, as the initial step in leak location thereby preventing a further inventory loss from the RCS. Connections to the RCS can then be reestablished one at a time, while maintaining inventory and cooling.

   c. Step 3.4; For entry into this procedure, the reactor coolant system would have to be less than 280°F with pressure less than 230 psig. This would provide for little OTSG cooling to be available. The most likely cooling method would be via the spent fuel cooling system as discussed in step 3.5. Therefore, the step 3.4 method of cooldown, which would apparently only apply after attempts to establish other methods for cooldown have failed and a plant heatup is occurring, should be placed later in the procedure.

   d. Step 3.4; RCPs will only be available over a narrow range of potential application of procedure AP-360. Under some conditions, it is not necessary for the RCS to be filled and vented for the OTSGs to be useful. Under two phase conditions, the OTSGs can provide a valuable temporary cooling function without feedwater being available due to the heat capacity of the contained inventory.

   e. Step 3.7; This step directs the closure of reactor building sump valves DHV-42 and DHV-43. Considering the conditions for entry into this procedure, there appears to be no reason why these valves were open (neither the procedure nor plant conditions require it). Therefore this step appears to be unnecessary.

      This step also directs LPI cooling by injecting from the BWST into the RCS. As presently directed by the procedure, it appears that the LPI will become deadheaded if there is no outlet from the RCS. Therefore the procedure should direct operators to provide a discharge path from the RCS if necessary (e.g., manually opening the PORV to assure cooling water flow through the RCS).

f. Step 3.9; This caution applies to LPI cooling with the RB sump in use. It is not applicable to water from the BWST.

g. Step 3.9; The intent of this step is not clear. It apparently assumes that LPI is not available from the BWST and that HPI is supplying the flooding water via the BWST. If HPI and BWST are not available, there appears to be no source for flooding the RB. By the time this step is entered, it appears to assume that the BWST is unavailable; therefore, if this is correct, it cannot be a source of water.

h. Step 3.10; This step should be preceded by a caution warning operators to be aware of and watch for indication of LPI pump cavitations due to low RB sump level.

2. AP-380, Engineered Safeguards Actuation, Revision 8

a. PRA investigations consistently identify loss of injection capability during transfer to the recirculation mode as a significant contributor to core melt probability. AP-380 step 3.29 addresses switching of HPI suctions from the BWST to the DHR pump discharge side. If for some reason the DHR pump(s) was (were) not developing head, immediate MUP pump damage could result. Because this operation is critical, the licensee should revise the procedure to include a caution statement prior to step 3.29 to warn the operators to ensure sufficient reactor building sump level prior to DHR recirculation initiation and proper DHR operation prior to individually switching HPI suctions. The same comment also holds for EP-290, Inadequate Core Cooling, steps 3.5 and 3.6 and any other location in the procedures where the same conditions exist.

b. Conflicting instructions should be resolved and corrected. For example, AP-380 steps 3.39 and 3.14 are similar in that the PORV is to be opened, yet 3.14 addresses only the RCS pressure limit of 2300 psig. Step 3.39 instructs the operator to open the PORV before exceeding 2300 psig whereas 3.14 uses a pressure greater than 2300 psig. VP-580 step 2.1, requires that RCS pressure be greater than or equal to 2300 psig, and uses the PORV or high point vents for pressure control. See also EP-290 step 3.3.

c. Step 3.10; The licensee should consider replacing "<u>IF</u> PORV is <u>NOT</u> open, <u>THEN</u> close RCV-11" by "<u>IF</u> PORV is closed, <u>THEN</u> close and reopen RCV-11". The negative statement is not consistent with the Writer's Guide.

d. Step 3.16; High point vent operation should be addressed if PORV operation is not obtained or does not provide the desired results.

e. Step 3.18; The comment regarding preference of RCP-1B should be a note prior to the instruction to start one RCP.

f. Steps 3.20 and 3.24; Step 3.14 could have resulted in opening of the pressurizer vent if the PORV is not available. Steps 3.20 and 3.24 should address this possibility.

g. Step 3.30; This step should be performed earlier in the procedure so that chemistry results will be available prior to the use of the sump.

h. Step 3.33; the action taken as a result of step 3.33 should be completed after the requirements of step 3.34 have been satisfied.

i. Step 3.34; The procedure should ensure that high point vents are closed.

j. Step 3.35; A step should be added to deal with the possibility of insufficient cooling as a result of actions taken in steps 3.34 and/or 3.35.

k. Step 3.36; A step should be added to deal with containment pressure increasing following termination of spray.

l. Step 3.37; The direction under this step is unclear in that when the SSOD is notified that VP-580 is completed, AP-380 requires a transfer to OP-209, Plant Cooldown. This exit point may be inappropriate in that all the actions required under AP-380 may not have been completed.

m. Step 3.39; The caution prior to step 3.38 states HPI cooling must be established prior to any opening of the PORV. Yet step 3.39 requires opening the PORV prior to exceeding any of several conditions. The conflict should be resolved.

3. AP-450, Emergency Feedwater Actuation, Revision 10

a. Step 3.20 is based on knowing hot well levels. The wide range hot well level gage in the control room is out of service. Control room operators indicated it had been inoperative for "a long time" and there were no immediate plans to return it to service. The licensee indicated that readings from local indicators of hot well levels could be obtained in less than five minutes and, at this stage of the procedures, this would not be a highly time critical step. Either the defective instrument should be repaired, or the procedure should explicitly indicate that hot well level should be determined locally.

4. AP-513, Toxic Gas, Revision 4

a. Step 2.2; This step requires that the operator ensure that dampers, including AHD-2 and AHD-99, are closed. Operators are not sure whether a blue status light will illuminate if <u>both</u> AHD-2 and AHD-99 close <u>or</u> if only AHD-2 closes. This understanding is aggravated by the incorrect labeling on the light.

b. Step 3.9; This step directs operation of a potentiometer, however, there are no instructions on which way to turn the potentiometer to achieve the desired result. Since the potentiometer is labeled with numbers, the procedure should provide information (e.g., turning the potentiometer toward 10 will increase flow) that would tell the operators the effect each direction of the potentiometer would have on flow.

5. AP-525, Continuous Control Rod Motion, Revision 0

Step 3.8; The procedure reference to technical specification 3.1.1.6 for safety rods and 3.1.3.5 for regulating rods is incorrect. Safety rods are discussed under 3.1.3.5 and regulating rods are discussed under 3.1.3.6.

6. AP-530, Natural Circulation, Revision 6

Step 3.24; The reference to Enclosure 2 for the natural circulation cooldown curve is incorrect. The correct curve is Enclosure 1.

7. AP-580, Reactor Trip, Revision 8

a. Step 2.3; The operator is instructed to initiate emergency boration by starting CAP-1A or CAP-1B, opening CAV-60, and establishing maximum letdown. This may provide a slow response. The licensee should consider a more rapid boration if needed, such as by use of HPI from the BWST.

b. Step 2.11; This step instructs the operator to close the block orifice bypass valve. This is incorrect if emergency boration is underway.

8. AP-660, Turbine Trip, Revision 4

Step 2.3; This step directs closure of the MSIVs. Closure of more than one MSIV requires a mandatory reactor trip. Therefore this step should direct operators to trip the reactor and refer them to the reactor trip procedure (AP-580).

9. AP-990, Shutdown from outside the Control Room, Revision 2

a. There were no calibration stickers on some of the instruments on the RSP. If these instruments are not in proper calibration there is a significant possibility for confusing and misleading the operator at the RSP. The inspection team found no calibration stickers on RC-5B-TI4-2 or RC-4B-TI4-2, and could not find documentation that these had been recently calibrated. The resident inspectors will follow up on this item.

b. The pressurizer level instrument on the RSP is not temperature compensated. In the control room there are two instruments, one compensated and one non-compensated. The compensated instrument is used unless the unit is in cold shutdown. If the unit is not in cold shutdown this would lead to a significant difference between the compensated instrument in the control room and the non-compensated instrument on the RSP. There is nothing in the procedures, or in the RSP labeling that warns the operator of this potential difference. A note to this effect should be included in the procedure and a label added to the RSP.

c. Step 3.6; The procedure requires isolation of letdown from outside of the control room to be performed at the RSP. However, transfer of control for these valves from the main control board to the RSP does not occur until step 3.12. The procedure should be revised to provide operations personnel the necessary information to isolate letdown if they are at the remote shutdown panel prior to step 3.12.

d. Step 3.21; The procedure states that if letdown cannot be established then decrease make-up flow. The details column states this can be accomplished by minimizing or isolating seal injection. During procedure walk-throughs, operations personnel indicated they would use MUV-31 to accomplish this action. The procedure should be clarified as to the preferred method for decreasing make-up flow.

10. EP-140, Emergency Reactivity Control, Revision 4

a. Step 3.5; This step states "IF RB is occupied, THEN evacuate RB." Walk-throughs of the procedure indicated some confusion among the operators as to how to determine if the RB Evacuation Alarm should be sounded. This should be resolved, and the procedure changed to clearly reflect the required action.

b. Step 3.6; This step directs the operator to stop all deborations. The licensee should consider closing all connections to the RCS except those connected with boration that is underway. Then the operator can selectively open connections and determine the source of the dilution.

11. EP-290, Inadequate Core Cooling, Revision 6

a. Steps 3.8 and 3.9; References to clad temperature are of no use to the operator and should be removed. It is sufficient that the operator be instructed to reference the proper ICC region and react accordingly.

b. Step 3.14; The RCP start permissives should be provided here to be consistent with other procedures.

c. Step 3.15; The licensee should consider reproducing this caution on the following facing pages because of the generality of the instruction.

d. Step 3.17; Operators have indicated they do not perform EM-308 and have no need for information from that procedure. The licensee should consider deleting this reference in EP-290.

e. Step 3.18; Guidance should be provided that the best indication is the one listed last in the step.

12. EP-390, Steam Generator Tube Leak, Revision 5

a. There are several steps within the procedure which require the operators to monitor and maintain parameters based on current plant conditions. These parameters include subcooling margin, fuel pin compression limits, OTSG levels and steaming requirements, and emergency cooldown limits. These items have been included within the procedure as enclosures or tables on the facing pages. To be consistent throughout the procedure when a reference to these parameters is made the appropriate table or enclosure should be annotated within the step. Examples of this deficiency can be found in steps 3.15, 3.18, 3.27.

b. Step 3.7; The procedure requires the operator to open one or more HPI valves to maintain pressurizer level. The procedure should be revised to include the use of MUV-24 first, thus reducing the possibility of thermal shock.

c. Step 3.19; The procedure requires the operator, if RCPs are not operating, to maintain RCS pressure above the natural circulation curve and increase cooldown to less than or equal to 50 degrees per hour. The wording of the cooldown requirements appears confusing and should be revised.

d. Step 3.19; The procedure requires the operators to refer to AP-530, Natural Circulation, Enclosure 1. To reduce the number of procedures the operator would be required to be in at once, a copy of Enclosure 1 from AP-530 should be included in the procedure.

e. Step 3.36; During procedure walk-throughs, operations personnel were unsure as to what the normal steaming requirements for an OTSG with both a tube leak and steam leak would be. The procedure should be revised to include the steaming requirements for an OTSG in this condition.

f. Step 3.36; The procedure states that if a steam leak is identified in the same OTSG that has a tube leak, and the steam leak is in the reactor building then allow the OTSG to steam to the reactor building. A statement should be included in the procedure to inform operators that due to the steam leak, localized temperature increases could cause instrument errors.

13. VP-540, Runback Verification Procedure, Revision 1

    a. Step 1.3; These details are too general. The first detail, referring to STS 3.1.3.1, is essentially repeated in step 1.4 which provides specific and useful guidance for control rod alignment. Therefore this detail should be deleted in step 1.3. The remaining details dealing with the STS limit for RCP operation need to be clarified such that the person performing the verification knows what needs to be verified in each of the STS sections listed. For example, STS 3.3.1.1 addresses the operability of the RPS. The intent of this step (i.e., whether the verifier should be checking all RPS instruments or specific instruments) is not clear.

    b. Step 2.2; This step requires reference to STS 3.3.1.1. The reason for reference to this STS is not clear. The step needs to be clarified to specify what should be verified. The same comment applies to the DETAIL section of this step. The verifier is referred to Computer Group 59, however, there is no guidance as to what in Computer Group 59 is to be verified.

    c. Step 3.1; This step directs the observation of radiation monitors for trends. This step should direct the observation of the radiation monitor recorder since trends are not easily determined on a monitor.

    d. Step 4.2; This step refers to AI-500, Step 2.4 as a means of determining the reporting requirements. Step 2.4 applies to the documentation of a reactor trip or shutdown and therefore does not appear to apply to a plant runback.

14. VP-580, Plant Safety Verification Procedure, Revision 8

    a. There appears to be no specific termination or exit criteria delineated within the procedure. The licensee should revise the procedure to include these items.

    b. Step 1.7; The licensee should examine this instruction for accuracy particularly with respect to the inequality sign and operator instructions for SGTR.

    c. Step 2.8; The licensee should consider the following wording for the last item to better reflect expected response: "WHEN OTSG PRESS is lowered, THEN verify Tc, incore TEMPs, and Th lower."

    d. Step 2.11; Recording of P-T data should be more often during transient conditions. (One of the SOTAs indicated plotting should not be initiated until the plant has stabilized - an incorrect decision since the information is most needed when the plant is in a transient condition.) Longer term plotting should also be considered since the information is useful in following plant state during the entire process.

e. Step 3.5; This step appears inconsistent, and is something that ordinarily would be done by the operating personnel. The licensee should examine this step to determine if the SOTA is expected to perform this step.

f. Step 4.3; The hotwell level instrumentation provided on the main control board reads in inches and the EOP references feet.

g. Page 9; This figure should be improved by showing acceptable regions and by providing contrast between the plotted information and the grid lines.

APPENDIX C

WRITER'S GUIDE AND HUMAN FACTORS DISCREPANCIES

The following are short descriptions of discrepancies between the Writer's Guide and EOPs or of discrepancies identified in the EOPs. The licensee agreed to evaluate these comments and take appropriate action. These items will be reviewed during a future NRC inspection.

1. General Problems

   a. A large number of labeling inconsistencies between the procedures and control room instrumentation and controls were identified. These are listed in Appendix D.

   b. There are only two copies of the EOPs and APs in the control room. An additional copy could be provided for use when multiple procedures are being performed, for use by the SOTA when performing VP's, and as a back-up for the current copies.

   c. Instructions to perform the same actions appear at a number of locations within the EOPs. Frequently these instructions are worded differently. Furthermore, sometimes the actual steps to be taken are inappropriately different. The licensee should examine all procedures and ensure consistency. An example of this is given below under AP-380. Additional examples may be found in AP-580 step 3.3 and EP-290 step 2.1.

   d. EOPs often inappropriately reference other procedures as information sources without indicating the specific steps or pages to be referenced. The step or page location should be specified whenever practical. Some examples are given in AP-380 below.

   e. Graphs and figures often do not contain grid lines, are sometimes unclear, and occasionally contain extraneous information not needed by the operator. These difficulties should be resolved and the procedures corrected. Examples are AP-380, page 39, which has no grid lines, EP-290, which has no grid lines and contains references to clad temperature which are of no immediate use to the operator, and EP-220, Enclosure 1, which contains handwritten information and has no grid lines.

2. EP-290, Inadequate Core Cooling, Revision 6

   a. Step 3.8; The caution located before this step should be clarified.

3. AP-380, Engineered Safeguards Actuation, Revision 8

   a. Step 3.15; This step references AP-530 but does not indicate what steps in the AP are applicable. The specific steps should be included in the reference.

b. Step 3.19; The intent of this action is that AP-530 should be used for subcooled natural circulation and AP-380 should be continued for inadequate subcooling margin. The wording should reflect the intent.

c. Similar actions are indicated in different steps, but are not consistent with each other. For example:

(1) Step 3.3; This step contains instructions to "Start full HPI" and step 3.38 is to "Establish full HPI". The actions of several of the steps are identical, although the wording is different.

(2) Other actions differ. For example, "Ensure greater than or equal to 2 MUPs and their cooling water pumps are running" versus "Start second MUP and its cooling water pumps and Ensure HPI flow is greater than 500 gpm."

(3) Step 3.3 is followed by 3.6 which has the operator balancing flow in the four injection lines. Step 3.38 has no corresponding action.

d. Step 3.21 refers to EP-390 but does not indicate which steps in the EP are applicable. The specific steps should be included in the reference.

4. AP-450, Emergency Feedwater Actuation, Revision 10

a. Step 3.8; The sub-step saying "GO TO AP-380" is located before the sub-step starting HPI. This would prevent HPI from starting for an unknown period of time.

b. Step 3.12 refers to OP-605 Section 9.0. There is no Section 9.0 in OP-605. This section is referred to in a number of other steps in this and other procedures.

c. Step 3.14 contains two logically separate steps, with some of the details referring to one step and some the other. This is not consistent with the Writer's Guide.

5. AP-460, Steam Generator Isolation Actuation, Revision 5

a. Step 3.6; This step contains two separate actions. The first action requires response if both emergency feedwater and main feedwater are not available. The second action requires response if emergency feedwater is not available. The Writer's Guide states that only one idea should be presented in an action step. The step should be revised to be consistent with the requirements of the Writer's Guide.

b. Throughout the procedures the Once-Through Steam Generators are referred to as OTSGs. On the main control room boards these are referred to as Steam enerators (STM GEN). On the RSP they are referred to as OTSGs.

c. Step 3.19 indicates that MSV-55 is located on DPDP-8A. It is actually located on DPDP-8B.

d. Step 3.27 instructs the operator to "trickle feed OTSG." No quantitative definition is given to tell the operator what flow would constitute a reasonable "trickle." When questioned about this, the operators indicated that a flow of less than 100 gpm would be reasonable. The procedure should be changed to define a "trickle" quantitatively.

6. AP-513, Toxic Gas, Revision 4

In step 3.12 the operator is referred to AH-35-FR to verify the proper flow. This recorder is labeled AHO-32-FIR on the back panel.

7. AP-530, Natural Circulation, Revision 6

a. Step 3.3; The logic statement when reproduced as a recurring step on the facing pages was not capitalized and underlined.

b. Enclosures 1, 2, and 3; The graphs do not contain grid lines and contain handwritten information.

8. AP-990, Shutdown from Outside Control Room, Revision 2

a. The "B" "RELAYS ENERGIZED" light on the RSP is covered with a green lens cap, while the "A" light has no lens cap. Since plant color conventions call for a red indicator to indicate energization, this discrepancy should be corrected.

b. No steam tables were available in the RSP room.

9. AP-1075, Violent Weather, Revision 9

a. Step 1 refers the operator to Enclosure 1 for definitions of entry conditions. This list is relatively short and should be included on the entry condition page.

b. In several steps (e.g., 3.3, 3.4, 3.5, and 3.6) the operator is instructed to perform an action (such as ensure SF Pool Missile Shields are in place). The procedure does not indicate who should be contacted and/or responsible for performing these tasks.

c. In Step 3.4 the procedure instructs the operator to perform pre-start checks on each EGDG. It does not instruct him to do this task concurrently, so the Writer's Guide would indicate that the remainder of the procedure would not be completed until the EGDG pre-start checks are completed. This is clearly in error. Most of the subsequent steps should be initiated immediately and performed concurrently with completion of the rest of the procedure. The procedure does not indicate that any of these steps should be performed concurrently, which would extend the time required to complete this procedure.

d. Enclosure 2 lists members of the violent weather preparation committee, but not their telephone numbers. These numbers should be provided in the enclosure.

APPENDIX D

NOMENCLATURE DISCREPANCIES IDENTIFIED
BY NRC EOP INSPECTION TEAM

Procedure	Step or Page	Procedure Nomenclature	Label on Equipment
AP-330	3.5	WDT-5A and WDT-5B	DW Transfer Pumps WTP6A, 6B
AP-330	3.3	SW Surge Tank	Nuc. Serv. Clg. Water Surge Tk. Level
AP-360	3.7, 3.10	LPI Suctions from RB Sump	DHP-1A, RB Sump, DHP-1B, RB Sump
AP-360	3.7	LPI Control Valves	DHHE-1B Dis, DHHE-1A Dis
AP-360	3.7	LPI Suctions from BWST	DHP-1A BWST Suct., DHP-1B BWST Suct.
AP-360	3.7, 3.10	LPI Discharge to RCS	DHP-1A LP Inj., DHP-1B LP Inj.
AP-360	3.8, 3.11	HPI Suctions from BWST	BWST to MUP
AP-360	3.11	LPI Discharges to HPI Suction	DHV-1A to MUPS, DHV-1B to MUPS
AP-360	3.13	CFT Outlets	CFT-1A Outlet Iso
AP-380	3.3	MUP suction valves from BWST	
		MUV-58	MUV-58 Hi Press. Suct.
		MUV-73	MUV-73 BWST to MUP
		All HPI Valves	
		MUV-23	MUV-23 HP Inj. Loop A
		MUV-24	MUV-24 HPI Loop A
		MUV-25	MUV-15 HPI Loop B
		MUV-26	MUV-26 HPI Loop B
AP-380	3.6	A and B HPI Channels	
		RC1	HP 1 RC1
		RC2	HP 1 RC2
		etc.	etc.
AP-380	3.7	RC4	HP 1 RC4
		RC5	HP 1 RC5
		RC6	HP 1 RC6

Procedure	Step or Page	Procedure Nomenclature	Label on Equipment
AP-380	3.8	A and B RBI Channels	
		RB1	RB ISO RB1
		et al., for six references total	
AP-380	3.9	BSV-3	BS HDR Inlet Iso.
		BSV-4	BS HDR Inlet Iso.
AP-380	3.10	RCV-11 (not identified)	RCT-1 to RCV-10
		RCS-13 PZR Spray Block	RCT-1 to RCV-10
		MUV-38 A Letdown Cooler Inlet Isolation	Iso. to MUHE-1A
		MUV-39 B Letdown Cooler Inlet Isolation	Iso. to MUHE-1B
		MUV-498 C Letdown Cooler Inlet Isolation	Iso. to MUHE-1C
		MUV-49 Letdown Isolation	High Temp Bypass
		DHV-3 (not identified)	-
AP-380	3.14	RCV-11 PORV Block	See 3.10
		PORV	DPDP 4B RCT-1 Relief RCV 10
		PZR Vent (not identified)	-
		RCV-11 PORV Block Valve	See above
AP-380	3.17	MUP Recircs.	MUP's Recirc.
		MUP Recirc. Valves	
AP-380	3.23	CFV-5	CFT-1A Outlet Iso.
		DFV-6	CFT-1B Outlet Iso.
AP-380	3.29	LPI Suction	
		DHV-34	DHP-1A BWST Suct.
		DHV-35	DHP-1B BWST Suct.
		DHP-1A	DH Removal Pump A
		DHP-1B	DH Removal Pump B
		LPI discharge to HPI Suctions	
		DHV-11	DHP-1A to MUPS
		HDV-12	DHP-1B to MUPS
		HPI Suctions from BWST	
		MUV-58	Hi Press. Suct.
		MUV-73	BWST to MUP

Procedure	Step or Page	Procedure Nomenclature	Label on Equipment
AP-380	3.32	LPI Suctions from BWST	
		DHV-34	DHP-1A BWST Suct.
		DHV-35	DHP-1B BWST Suct.
AP-380	3.35	EFW-56	EFV-56
		EFW-58	EFV-58
		EFW-55	EFV-55
		EFW-57	EFV-57
AP-450	pg.1	OTSG Level	Stm. Gen. Lvl.
	3.12	FWV-39B Startup Control	FWV-39B SU FW Vlv.
	pg.13	MFW Flow	FW to Stm. Gen.
	3.15	EFW	EFV
	3.2	CDHE-3 Inlet	Disch. Iso.
	3.23	EFW Control Valves	EFV Control Valves
AP-460	pg.1	OTSG Press.	Stm. Gen. A/B Press.
	pg.8	Subcooling Margin	Saturation Margin
	3.19	MSV-55, DPDP-8A	MSV-55, DPDP-8B
	3.21	SU Control Valves	Stm. Gen. B SU FW Vlv.
	3.23	OTSG Level Chart	Stm. Gen.
	3.26	EFT-2 Level	EF Tank Level
	3.29	A SU Block	A SU FW Block
		B SU Block	B SU FW Block
	3.30	ASV-5/204	ASV-5 and ASV-204
		EFW Control Valves	EFV-55 through 58
AP-513	2.1	Heating & Ventilation Control Panel	Control Complex HVAC
AP-513	2.2	AHD-2 AHD-99	D2 CC Rel. Air Damper Closed
AP-513	3.9	"CC Damp Override"	Damp Override
AP-513	3.9	"AH-193-FC"	Cntrl. Complex Recirc. Damper
AP-513	3.12	AH-35-FR	Top of Recorder: Control Complex Supply Air RB & AB Air Sys. Bottom of Recorder: Supply & Exh. Air Monitoring AH-032-FIR A-Control Complex Air Supply

Procedure	Step or Page	Procedure Nomenclature	Label on Equipment
AP-513	3.9	"CC Damp Override"	Damper Override
AP-513	3.12	AH-35-FR	AHO-32-FIR
AP-530	2.2	65% Level	50%/30"
AP-530	3.3	HPI Valves	HPI Loop A,B HP Inj. Loop A
AP-530	3.26	MFW Block	Main FW Block
AP-530	3.26	LL Block	Lo Load FW Block
AP-530	3.26	Startup Control	SU FW VLV
AP-530	3.26	Cross-Tie	FW Disch. Crosstie
AP-530	3.26	SU Block	SU FW Block
AP-770	3.4	ES 480V	480V ES Bus A,B
AP-770	3.5	ES-MCC-3AB	ES-MCC-3a2
AP-770	3.6	Seal Injection Control Valve	RC Pump Total Seal Inlet Flow
AP-770	3.6	Seal Injection Block Valve	RC PP Seal Supply
AP-770	3.7	SW Raw Water Press.	Nuc. Serv. Sea Wtr. Pump Disch. Pressure
AP-990	3.2	CRD Bkr. A CRD Bkr. B	Feeder No. 1 Feeder No. 2
	3.6	Letdown Isolation Valve	Letdown Clr. Iso.
	3.8	RCV-11 PORV Block Valve	RCT-1 Block Valve
	3.12	"AB" and "non-safety" controls	Transfer switch "AB" and Transfer SW non-safety
	3.14	"Voltage Adj"	VP Adjust
	3.16	MUP Suction Valves	BWST HP Suct. and BWST to MUP
AP-990	3.16	HPI Valves	HP Inj.
	3.19	MUV-53 MUV-257	MUPP Recirc. 53 MUPP PP Recirc.
	3.23	RCP Seal Return Seal Isolation	RCP Bleed Iso. RB Bleed off Iso.

Procedure	Step or Page	Procedure Nomenclature	Label on Equipment
EP-390	3.3 page 5 of 35	MUV Block Orifice Bypass	MUV-51 also MU-3-MIC no mention of Block Orifice Bypass
EP-390	3.5 page 5 of 35	Comment same as above	Comment same as above not labeled Block Orifice Bypass
EP-390	3.7 page 7 of 35	Comment same as above	Comment same as above not labeled Block Orifice Bypass
EP-390	3.7 page 7 of 35	MUP Suction Valves MUV-58, MUV-73	58 - Hi Press. Suct. 73 - BWST to MUP
None	None	MUV 23 Label differs from MUV 24, 25, & 26	MUV 23 indicates HP Inj. Loop A other are HPI Loop A-B
EP-390	Various	Reference to OTSG*	Steam Generator on Labels
EP-390	315	Per Spray PORV	RCT-1 SPR Cntrl. RCV-14 RCT-1 Relief RCV-10
EP-390	Various	65% Level	Level Select Pushbutton 50%/30"
EP-390	3.25	MSV-55, MSV-56 EFP Supply	RCSG - Should have been Deleted
EP-390	3.27	Same Comment as Step 3.15	Same Comment as 3.15
VP-540	3.2	MS Radiation Monitors	1) No labels on recorders 2) Recorder scale in linear, 0-100, meter face is logrithmic, 0.1-10^7 MR/h, no correlation between the two. 3) Monitors labeled as: A-1 RMG 25 (ADV MSV-25) A-2 RMG 27 B-1 RMG 26

*OTSG is on Control Board for L Chan. EFIC Act. Bypass.

Procedure	Step or Page	Procedure Nomenclature	Label on Equipment
			B-2 RMG 28 (ADV MSV-26)
VP-540	3.4	RCP Seals and Dumpsters	1) RC-19A, PR-1(A) RC-19B, PR-1(C) RC-19A, PR-2(B) RC-19B, PR-2(D) 2) No labeling on dumpster integrators 3) Recorder labeled: RC Pump Seal Leakage RC-134-FIR (Dumpster Clics)
VP-540	3.4	RCDT Level	RC Drn. Tnk. Level
VP-540	3.4	MUT Level	MU Tank Level
VP-540	3.4	RB Sump Level	RB Sump A Level RB Sump B Level
	3.4	Relief Valve Tailpipe Temps.	R205 Press. Relief Vlv. RCV-8 out Temp. R206 Press. Relief Vlv.-9 out Temp. R207 Press. Relief Vlv. RCV-10 out Temp. Note: This labeling is not in agreement with the computer points.
VP-580	3.4	RML-1	RM-LI
VP-580	4.3	EFT-2	EF Tank
VP-580	4.3	EFT-2	EF Tank

APPENDIX E

LIST OF ABBREVIATIONS

AP	Abnormal Procedure
ATOG	Abnormal Transient Operating Guidelines
BWST	Borated Water Storage Tank
CR	Control Room
DHR	Decay Heat Removal
EGDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
ES	Engineered Safeguards
GTG	Generic Technical Guidelines
HED	Human Engineering Deficiencies
HPI	High Pressure Injection
ICC	Inadequate Core Cooling
LPI	Low Pressure Injection
MSIV	Main Steam Isolation Valve
MUP	Makeup Pump
NRC	Nuclear Regulatory Commission
OP	Operating Procedure
OTSG	Once Through Steam Generator
PORV	Power Operated Relief Valve
PRA	Probabilistic Risk Assessment
RB	Reactor Building
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RPS	Reactor Protection System
RSP	Remote Shutdown Panel
SOTA	Shift Operations Technical Advisor
SSOD	Shift Supervisor On Duty
STM GEN	Steam Generator
STS	Standardized Technical Specifications
VP	Verification Procedure
V&V	Validation & Verification