U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Licensee: GPU Nuclear Corporation
P. O. Box 480
Middletown, Pennsylvania 17057

Docket No.: 50-289

License No.: DPR-50

Facility Name: Three Mile Island Nuclear Station, Unit 1

Inspection Conducted: March 6 - March 17, 1989

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SUMMARY

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

Results: No violations or deviations were identified. Although human factor deficiencies and deviations from the plant specific guidelines 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.

DETAILS

1. Persons Contacted

Licensee Employees

* J. Colitz, Director, Plant Engineering
  J. Fornicola, Manager, Quality Assurance
* C. Hartman, Manager, Plant Engineering
* H. Hukill, Director, TMI-1
  C. Incorvati, Manager, TMI Audit
* G. Jaffa, Engineer, Human Factors
* R. Knight, Engineer, Licensing
  L. Lanese, Manager, Mechanical Systems
* R. Maag, Supervisor, Operator Training
  M. Nelson, Manager, Nuclear Safety
* M. Ross, Director, Plant Operations
  O. Shalikashvili, Manager, Plant Training
* H. Shipman, Manager, Operations Engineering
* C. Smyth, Manager, Licensing
* M. Trump, Supervisor, Simulator
* P. Walsh, Director, Nuclear Analysis and Fuels

The team contacted other licensee employes including engineers, technicians, operators and office personnel.

Commonwealth of Pennsylvania

* R. Cook, Nuclear Engineer
* S. Peleschak, Nuclear Engineer

NRC Attendees

  C. Cowgill, Chief, DRP Section, Region I
* R. Conti, Chief, BWR Section, Region I
* R. Hernan, Senior Project Manager, NRR
* T. Moslak, SRI (Acting)
* W. Regan, Chief, Human Factors Assessment Branch
* F. Young, SRI

* Attended Exit Meeting on March 17, 1989.

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

2. EOP/GTG Comparison

The inspection team conducted a review to ensure that the licensee had developed sufficient procedures in appropriate areas to cover the broad spectrum of accidents and equipment failures.

The plant-specific Abnormal Transient Procedures, 1210 series, were derived from the NRC staff approved version of the Oconee ATOG (Rev. 1). Differences from the baseline documents are explained in TDR-517, Revision 2 dated July 1, 1988. In order to verify that the TMI-1 Abnormal Transient Procedures covered all required ATOG procedures, the inspection team compared the ATOG Table of Contents to the TMI-1 1210 series Table of Contents. No ATOG-based procedures were omitted at TMI. Individual ATOG-based steps that were changed were justified and documented in TDR-517, Revision 2 except as noted in Appendix C.

The inspection team compared the TMI-1 1210, 1202, and 1203 procedures with the procedures identified in Regulatory Guide 1.33, Section 6. No omissions were identified.

It was the inspection team's judgment that the licensee designed and implemented a set of emergency operating procedures that are consistent with the Oconee ATOG and Regulatory Guide 1.33, Section 6.

There were no violations or deviations noted in this area.

3. Independent Technical Adequacy Review of the EOPs

(Note: The references used in this section are described in Appendix E.)

The basic licensee EOPs are the 1210 series, the TMI-1 Abnormal Transient Procedures. These are related to the NRC staff approved version of the Oconee ATOG (Ref. 1), which initially served as the generic emergency procedures for the B&W designed nuclear steam supply systems. More recently, the licensee has moved from the Oconee ATOG to the Technical Bases Document (TBD, Ref. 2) as the bases for the 1210 series procedures. The general organization and entry conditions of the Oconee ATOG are retained in the 1210 series procedures.

Reference 3 is the formal Plant Specific Guideline (PSG) for TMI Unit 1. This PSG version was generated in response to staff questions regarding application of ATOG and the TBD to TMI, and was transmitted to the staff for formal review on June 29, 1984. The staff is just completing that review and expects to issue a safety evaluation report.

A newer version of the PSG (Ref. 4) was provided to the inspectors at the beginning of this inspection activity, and constitutes the PSG upon which a part of the inspection was based. The 1210 series of procedures are derived from this PSG.

References 3 and 4 contain a documented technical description of differences between the PSG and the generic bases documents (Refs. 1 and 2), as well as covering differences between revisions 1 and 2 of the PSG. The team conducted an audit of references 3 and 4 and compared them to all of the 1210 procedures. The team conducted a technical assessment of these

procedures and, with the exception of minor difficulties which are documented in Appendices B and C, determined that:

1. The recommended vendor step sequence is followed.

2. Entry/exit points are correct and are easily followed.

3. Transfer between procedures is reasonably defined and appropriate.

4. Use of notes and cautions is correct and appropriate.

The team verified the prioritization of accident mitigation strategies in the procedures to be similar to those recommended by the vendor owners group with the exception of reversing the order of overcooling and loss of heat transfer conditions. (The vendor owners group appraised these as of equal priority, but ordered them in the reverse of the TMI ordering in ATOG.) The licensee has addressed this change in the referenced material, and the team reviewed this justification and no problems were identified.

The team audited the deviations between the PSG submitted to the staff for review and the series 1210 procedures via audit of the licensee described deviations in references 3 and 4 and via our independent evaluation. The team considered safety significance and plant specific design features in that audit. With the exception of minor difficulties which are documented in Appendices B and C, the team determined that the deviations have a reasonable basis and have been incorporated to enhance application of the vendor guidance at the licensee's facility.

The team's overall technical adequacy appraisal is that:

1. The licensee has demonstrated an excellent understanding of both the vendor owners group recommendations and individual features of the TMI plant.

2. The licensee has effectively applied this knowledge to development of 1210 series procedures that cover operation within the scope of transients covered by the owners group recommendations.

3. The number of minor errors which were found appeared to be due to failure to conduct an adequate verification/quality control program and due to incorporation of improvements into the procedures prior to careful evaluation and updating of the PSGs.

4. The existing 1210 series procedures provide effective operator guidance within the scope of the subjects covered by the vendor owners group recommendations.

There were no violations or deviations noted in this area.

4. Review of the EOPs by Inplant and Control Room Walk-throughs

A review of the ATPs was conducted via in-plant and control room walk-throughs of the emergency and normal operating procedures listed in Appendix A. The emergency procedures appeared to be consistent between the instrumentation and control labeling on the control board and the nomenclature used in the procedures. Those discrepancies noted are enumerated in Appendix B. The majority of the discrepancies in Appendix B originated from the abnormal procedures.

Indicators, annunciators and controls referenced in the EOPs were found to be available to the operators. The emergency procedures and abnormal procedures maintained in the control room were well placed and readily available to the operators. These procedures were verified to be of the latest revision and free of any handwritten notes. While the results of the walk-throughs were generally positive, discrepancies in the area of Writers Guide adherence, human factors, and PSG changes were noted. Writers Guide and Human Factors discrepancies are contained in Appendix B, while Appendix C contains differences between the ATPs and the PSGs. The licensee committed to review and resolve the discrepancies identified in the aforementioned appendices.

Appendix B discrepancies will be identified as Open Item 289/89-80-01.

Appendix C discrepancies will be identified as Open Item 289/89-80-02.

During the inspection, the aspects of the validation and verification program that were applied to the development of the EOPs were not inspected in depth.

There were no violations or deviations noted in this area.

5. Simulator Observations

The NRC observed a crew of licensed operators perform the following seven scenarios on the TMI Unit-1 simulator:

a. Rx power 50%, BOL, Boron 1100 ppm
   Malfunction 1. Loss of off site power
   2. "B" DG starts, but fails to load. Do Not allow loading

b. Rx power 100%, MOL, Boron 400 ppm
   Malfunction 1. Main Steam Line Break in "A" Main Steam Header in containment. Break size is 10% flow approximately 6E6 lb/hr.
   2. Immediately after the trip -- SGTR "B" OTSG of 400 gpm.

c. Rx power 50%, MOL, Boron 400 ppm
Malfunction 1. One of loop "A" RCPs trips.
2. Loop "B" MFW CV fails "sticks"open.
3. Post trip loss of all Main and Emergency Feedwater.
4. Restore feedwater and recover from HPI Cooling.

d. Rx power 100% EOL, Boron 50-75 ppm
Malfunction 1. Loss of all RCPs (Loss of NSCCW)
2. 200 gpm tube leak in "B" OTSG

e. Rx power 100% EOL, Boron 50 ppm.
Malfunction 1. Rx manual/auto trip failure
2. Fail both Main Feedwater Pumps at power.
3. Primary code safety valve fails open post trip, and the primary system settles out at approximately 100#.

f. Rx power 100%, BOL. Boron 1100 ppm
Malfunction 1. Fail 3 control rods in the full out position. Locate the 3 rods together and near an intermediate detector.
2. Loss of all ICS/NNI sub feeder power at 100% reactor power.

NOTE: Allow power to be restored 10 minutes after the trip.

g. Rx power 100%, EOL, Boron 50 ppm
Malfunction 1. Large break LOCA at "B" LPI/Core Flood nozzle. The break flow (pressure) steadied out at approximately 60#.

The procedures did not cause the operators to physically interfere with each other while performing the ATPs, APs and EPs. The procedures did not duplicate operator actions unless required (e.g. for independent verification). Activities that should occur outside the control room were initiated by the operators and proper confirmation of their completion was given. These actions were investigated during in-plant walk-throughs of the procedures.

It was noted that the ROs would frequently hold private conversation and not hear instructions from the Shift Foreman/Shift Supervisor.

During one scenario, the Shift Foreman was using the emergency procedures to give direction to the ROs, while the Shift Supervisor was directing activities of the ROs without reference to any procedure.

The ATP lesson plans are expected to cover both the technical basis behind the procedures and their structure and format. In reviewing the ATP lesson plans, the major emphasis of the lesson plans was placed on the

operator familiarity with the procedural steps, and minor emphasis was placed on the intent or basis of the procedural step. The licensee has devoted much effort into the development of the EOPs and has intentionally taken a simplistic approach in the structure of the procedures. The basic necessary steps to mitigate a symptom oriented event are contained in the EOPs, but the major prompting for operator action relies on operator knowledge and referencing of other procedures.

The procedures provided operators with sufficient guidance in the Immediate Actions to fulfill their responsibilities and required actions during the emergencies. Difficulties were experienced in the follow up actions of the procedures.

When a transition from the ATP to another procedure was required, precautions were taken to ensure that all necessary steps, prerequisites, initial conditions, etc. were met. The crew experienced difficulty when the scenario was carried past the normal termination point in the follow up actions. The difficulties encountered were where to enter and exit the procedures, and when to perform certain steps. The three events were:

Scenario 7: The crew tried to place both Decay Heat Pumps on the Decay Heat Drop Line at 300F during a large break LOCA with 18 feet in the BWST. This was an improper action and caused both DH pumps to trip on vibration due to vortexing.

Scenario 4: The RO was instructed to maintain a 50-70 deg./hr cooldown rate in Natural Circulation during a SGTR. This caused a large bubble to form in the head and insurge the pressurizer. The crew was unsure of what actions to take at this point.

Scenario 2: There was crew discussion on when to start the cooldown during a SGTR. The SRO wanted to depressurize to the minimum subcooling margins before cooling down, and the RO wanted to cooldown and depressurize at the same time.

The facility Training Department has recently instituted new lesson plans which utilize the simulator and a show, freeze, and discuss technique for teaching the EOPs. The lesson plans teach both the steps and the reasons for the steps, and should correct the procedural deficiencies discussed above.

There were no violations or deviations noted in this area.

6. Ongoing Evaluation of the EOPs

Procedures and records were reviewed, and licensee personnel were interviewed to determine whether the facility had established an acceptable program for continuing evaluation of the EOPs. With the below exceptions, the program for ongoing evaluation of the EOPs appears to be acceptable.

a. The inspectors determined that Administrative Procedures 1001D and 1001A provided adequate controls over the preparation, review and approval of the emergency procedures, with one exception. The QA organization is not actively involved, either directly or indirectly, in the formal review process of the EOPs. The QA organization's involvement is an after the fact review of the EOPs by means of (1) monitoring of the operators' ability to use the procedures when they are utilized in the control room during an actual trip or in the simulator during training; or (2) annual reviews of the operations department by the on-site audit group. With the exception of the last audit, no in-depth reviews of the procedures had been performed. The team stated that this condition is contrary to the intent of NUREG-0899, paragraph 4.4, which provides that the plant-specific technical guidelines be subject to examination under the Quality Assurance program. (Open Item 50-289/89-80-03).

b. The licensee's Administrative Procedure 1001K requires a biennial review of each procedure. The checklist used for the review basically requires a desk top review of the procedure for technical adequacy and a plant walk-through to ensure useability. This type of review should have identified many of the weaknesses identified by the inspection team. The licensee needs to strengthen the biennial review process. (Open Item 50-289/89-80-04).

c. Appendix C lists the deficiencies noted with respect to TDR-517. There does not appear to be any formal process to ensure that the technical guidance document will be maintained current. This is not consistent with NUREG-0899, which requires the licensee to ensure that the technical guidelines are maintained accurate and up to date. The licensee indicated that a formal program for the maintenance of the TDR-517 consistent with safety significant changes to the EPs will be created. (Open Item 50-289/89-80-05)

There were no violations or deviations noted in this area.

7. <u>EOP User Interviews</u>

The inspection team conducted interviews with five control room operators and five shift foremen (Shift Reactor Operators) and determined that the current EOPs satisfy the needs of the operational personnel. The operators interviewed felt the EOPs were adequate and compatible with the level of knowledge of the typical operator and the operations staff were confident that the EOPs would function effectively during an actual event. The operators did express an interest in more frequent training on the technical bases of EOP steps.

There were no violations or deviations noted in this area.

8. Exit Interview

The inspection scope and findings were summarized on March 17, 1989, with those persons indicated in paragraph 1. The NRC 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. Those items on which dissenting comments were received from the licensee are identified by a marginal asterisk in the detailed discussion of the report.

Item Number	Status	Description/Reference Paragraph
IFI 50-289/89-80-01	Open	Correction of Human Factor discrepancies contained in the EOPs as outlined in Appendix B. (paragraph 4)
IFI 50-289/89-80-02	Open	Correction of deviations between the PSGs and the ATPs as outlined in Appendix C. (paragraph 4)
IFI 50-289/89-80-03	Open	Resolution of QA involvement in the ongoing evaluation of EOPs. (paragraph 6a)
IFI 50-289/89-80-04	Open	Strengthening of the biennial review process for procedures. (paragraph 6b)
IFI 50-289/89-80-05	Open	Establish a formal program for updating the PSGs when safety significant changes to the ATPs are made. (paragraph 6c)

APPENDIX A

PROCEDURES REVIEWED

NUMBER	TITLE	REV
Emergency Procedures		
1202-2	Loss of Offsite Power	25
1202-2A	Station Blackout with Loss of Both Diesel Gen.	21
1202-8	CRD Equipment Failures - CRD Malfunction Action	36
1202-9A	Loss of "A" DC Distribution System	22
1202-9B	Loss of "B" DC Distribution System	20
1202-11	High Activity in Reactor Coolant	17
1202-12	Excessive Radiation Levels	31
1202-14	Loss of RC Flow, RC Pump Trip	25
1202-17	Loss of Intermediate Cooling System	7
1202-29	Pressurizer System Failure	36
1202-30	Earthquake	21
1202-31	Fire	37
1202-32	Flood	22
1202-33	Tornado/High Winds	5
1202-35	Loss of Decay Heat Removal System	17
1202-36	Loss of Instrument Air	16
1202-37	Cooldown From Outside the Control Room	37
1202-38	Nuclear Services River Water Failure	22
1202-40	Loss of ICS Hand and Auto Power	16
1202-41	Total or Partial Loss of ICS/NNI Hand Power	14
1202-42	Total or Partial Loss of ICS/NNI Auto Power	15
Abnormal Procedures		
1203-1	Load Rejection	15
1203-5	High Cation Conductivity in the Condensate and / or Feedwater System	13
1203-7	Hand Calculations for Quadrant Power Tilt and Core Power Imbalance	23
1203-10	Unanticipated Criticality	10
1203-15	Loss of RC Makeup	12
1203-16	Reactor Coolant Pump and Motor Malfunction	25
1203-19	River Water System Failure (DR/SR)	8
1203-20	Nuclear Services Closed Cooling Systems Failure	8
1203-21	SSCC System Failure	5
1203-24	Steam Leak	24
1203-28	Post Accident H2 Purge	14
1203-34	Control Building Ventilation	13
1203-40	Loose Parts Monitor System	16
1203-41	Low System (Grid) Voltage	8
1203-42	Inadvertent Closure of a Main Steam Isolation Valve	5
1203-43	Transfer Canal Seal Plate Gasket Failure	3
1203-44	Hazardous Releases	12

Abnormal Procedures

1210-1	Reactor Trip	18
1210-2	Loss of 25 Degree F Subcooled Margin	11
1210-3	Excessive Cooling	12
1210-4	Lack of Primary to Secondary Heat Transfer	12
1210-5	OTSG Tube Leak/Rupture	14
1210-6	Small Break LOCA Cooldown	13
1210-7	Large Break LOCA Cooldown	12
1210-8	RCS Superheated	12
1210-9	HPI Cooling - Recovery From Solid Operations	13
1210-10	Abnormal Transients Rules, Guides and Graphs	18

Operating and Chemistry Procedures

1102-12	Hydrogen Addition & Degassification	13
1104-62	Hydrogen Recombiner	18
N1831	Post Accident Atmospheric Sampling	3

APPENDIX B

HUMAN FACTOR COMMENTS

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

COMMENTS AND OBSERVATIONS

1. General Comments

   a. Contrary to the writer's guide, notes and cautions often follow the step to which they apply (e.g. EP 1202-2 pg. 3.0; 1202-2A pg. 4.0; 1202-9A pg. 6.0; 12202-9B pg. 6.0; 1203-1 pg. 3.0; 1203-41 pg. 2.0; 1210-4 pg. 3.0; 1210-6 pg. 4.0; 1210-8 pg. E2-1; 1210-9 pg. 2.0; 1210-10 pg. 6.0 and many others).

   b. Although several documents list set points for automatic signal initiations, TMI has no EOP oriented operator action set point document, a document which would provide procedure writers and reviewers with a controlled single source document containing operator action parameter values and the basis therefore. As a result, procedure writers derive their own values for use in the EOPs and occasional conflict results (e.g. EDG output voltage as listed in procedures 1202.2, 1202.2A, and 1203-41 which specify 4000-4300, >4100, and 4000-4200 respectively.

   c. Although ATP 1210-10 is clearly applicable to the ATPs, by omission it's applicability to the EPs and APs is undefined. However, it is necessary for EP/AP implementation. For example, some of the EPs and APs require natural circulation verification. The only definition of natural circulation verification is the one in ATP 1210-10.

   d. Based upon the number of errors identified in the 1202.2 and 1202.2A Emergency Procedures, the team concluded that the validation and verification process applied to those procedures yielded inadequate results.

   e. The IF, THEN format is used to designate when remedial actions are required (IF) and what those remedial actions should be (THEN). The procedures do not provide the details as to how those remedial actions are to be accomplished, nor do they detail the preferred and alternate methods. Example, in the reactor trip procedure 1210-1, "IF one or more rods are stuck out, THEN emergency borate."

   f. The Writer's Guide for ATPs (AP-1001E) states that when the ATPs refer to other procedure series, both the procedure number and the title should be given. This is not normally done, only the procedure number is provided within the THEN column.

2. 1210-1 Reactor Trip

a. Step 2.5: There is inconsistency in designating valves. Often the name is used, other times the valve number, and sometimes both are used. Nor is consistency maintained within the inconsistency as in 1210-1 Step 2.5 where the instruction uses "isolate letdown and seal return" and the PSG uses "isolate seal return (MU-V26)."

b. Step 3.3. The step instructs the operator to verify atmospheric relief valve control if condenser vacuum is lost, but these valves are labeled Dump Valves on MS-V-4A and MS-V-4B.

c. Step 3.7.1. The step instructs the operator to verify AC Motor Suction Pump operating, but, there it is actually referring to the Bearing Oil Suction Pump.

d. Step 3.15. This step instructs the operator to determine and evaluate the cause of Reactor Trip per Attachment 1 of AP1063, but, the most current version, Revision 14, uses Enclosure 2 to document the cause of the trip.

3. 1210-3 Excessive Cooling

* a. Step 2.13: Make the statement: "Evaluate for PTS per ATP 1210-10, Figure 1 and 1A. Throttle HPI and if necessary open the PZR vent and/or PORV to prevent violation of PTS criteria" a separate step.

The reason for preventing the heatup and repressurization is due to the large mass addition from HPI injection, if the RCS was allowed to heat up, it would insurge the pressurizer and cause a over pressure condition.

4. 1210-4 Lack of Primary to Secondary Heat Transfer

a. Step 2.5: During walkthroughs, the operators were not clear whether the PORV should be operated intermittently to maintain >100 PSIG above OTSG. The procedure did not direct maintaining that dp. The team concluded that this uncertainty stemmed from a training deficiency.

b. Steps 1.5.2 and 1.5.4: Minor confusion exists because these steps are not sequential. For example, assume a stuck open PORV; until the operator reads the follow on statements about HPI confirmation and PORV opening, the intent is not clear yet he is directed to open the block with a stuck open PORV.

c. Step 2.5: The EOP "THEN" statement contains multiple actions which would be better presented as bullet items.

d. Step 2.8 then: The direction to close the open hotleg vents "if necessary" is insufficient direction to define required operator action.

5. 1210-5 OTSG Tube Leak/Rupture

* a. General: Entry into an ATP without a reactor trip being present is contradictory in that you are not in an abnormal transient by definition.

Step 3.0: If this procedure is not entered directly, but is entered from 1210-1, then a note needs to be added that steps x.xx through y.yy do not need to be accomplished since they are pre-trip actions.

* b. Step 2.0: The steps listed under this section should not be considered immediate actions since they are not required to be memorized.

c. Step 2.2 needs revision: Reword: "... THEN go to 1210-1."

d. Step 3.9.b needs revision: "Trip the reactor, immediately adjust turbine bypass valves closed to control initial cooldown, and go to 1210-1. Absent any higher priorities, return to this step."

e. Caution before Step 3.20: This caution belongs before step 3.11.

f. Caution before Step 3.20 needs revision: "Good cooldown control is by steaming both OTSGs. Isolate the affected OTSG when: ..." The licensee needs to reword the caution to address both conditions; i.e. when the OTSG should be isolated and when the OTSG should not be isolated.

g. Caution before Step 3.20: The calculation of the dose rates offsite is normally performed by the Health Physics Supervisor (in the capacity of Radiation Assessment Coordinator) via a computer program. Three copies of the program exist. Additionally, the HP Supervisor was very knowledgeable about the use of the program.

h. Note before Step 3.20: Include as a step vice a note.

i. Step 3.21 needs revision: "... THEN go to 1210-9."

j. Step 3.25: It is not be necessary to continue to call the Unit 2 control room to isolate the auxiliary steam cross connect valves as they are locked closed and red tagged.

* k. Step 3.28: The step needs to address the procedure (1104-4) to be used to place DHR in operation. This will incorporate the consideration that there is also a pressure limitation associated with the system.

* 1. Step 5.1.B.1, page E1-3: The differentiation for an Alert vice a Site Area Emergency is ≤50 gpm, which equates to 1.67 in/min change in the makeup tank. The thumb rule given is to use 2 in/min which is less conservative. The licensee will correct the note.

6. 1210-6 Small Break LOCA Cooldown

a. Steps 2.5: There are two steps labeled 2.5.

b. First step 2.5: Typo; delete semi colon in the "IF" statement.

c. Step 2.10: The sequence and presentation of these valves is different than that of 1210-8 step 2.6.3.

7. 1210-8 RCS Superheated

* a. The entry condition for this procedure is from 1210-2:

Step 2.6:
IF incore thermocouples indicate superheat; THEN go to ATP 1210-8

When does "superheat" exist, by definition? (As in loss of subcooling margin exists when SCM is less than 25°). The step does not adequately identify a superheated condition or basis for entering ATP 1210-8.

b. Step 2.5 and Attachment 3: The procedure needs to follow the practice of the PSG and the Tech Specs in describing areas as "area A" rather than "beyond curve A" since beyond may be either side of the curve.

c. Step 2.5.1 needs revision: "IF left of curve A; THEN ..."

d. Caution after step 2.6.1: typo; close parenthesis after 150 psig.

e. Step 2.6.5 needs revision: "WHEN hydrogen concentration is greater than 0.5% AND RB pressure is <10 psig, THEN start the hydrogen recombiners (OP 1104-62)" This is similar to the wording used in TDR-517.

f. Steps 2.6.5 and 2.7.7 of this procedure, step 2.18 of 1210-7, and step 2.21 of 1210-6 are all identical in intent, but the format is not standardized.

g. Step 2.6.8: The step assumes the RCPs are on. The pumps could be on or off at this point (2.6.3). Revise the procedure to provide direction for the pumps off and pumps on alternatives.

h. Caution before Step 2.7.6: TYPO: "... AH-E-1A/B/C must remain ..."

i. Step 2.7.7 of this procedure and Step 2.21 of 1210-7: both address the hydrogen recombiners and should be reworded accordingly.

j. Step 2.7.8: The procedure does not cleary identify this step as a hold point until core Tcs have reached saturation.

k. Step 2.7.11 needs revision: "GO to 1210-6 to establish ..."

l. Attachment 1: The PORV jumper procedure applies in other procedures but appears only in this procedure.

8. 1210-9 HPI Cooling - Recovery from Solid Operations

* a. Step 2.7: Usual transfers are go to or refer to; "follow" is not defined in the Writer's Guide.

b. Notes before step 2.11 and 2.13.2 are incorrectly sequenced.

c. Step 2.11: Insert "is" after "... and RCS pressure" in the IF statement. Evaluate whether this step should be an IF or a WHEN statement.

d. Step 2.13.4: The valves are not specified.

9. 1210-10 Abnormal Transients Rules, Guides and Graphs

* a. Step 1.2.1 needs revision: "1600 psig ESAS actuated or required."

b. Step 2.1.1: TYPO: "... available (See NPSH curve on Figure 1 or 1A) ..."

c. Steps 2.10.3/4: The setpoints in the computer at the simulator are not in agreement with this procedure. The setpoints in the Control Room computer are set 10°F conservative.

d. Figure 1, Note 1: needs revision "... < 500 psig go to Figure 1A"

e. Figure 1 & 1A, Note 5.a: This conflicts with other portions of the ATPs which allow the use of Th if natural circulation is confirmed.

f. Figure 1, Note 7: The type of indication to be used is not specified.

10. 1202-2 Loss of Offsite Power

a. Step 2.0 A 7: This step incorrectly states that (both) the 1D and 1E 4KV busses will automatically energize within 10 seconds. Only one bus need be energized; loss of both is a transfer to blackout.

b. Step 2.0 B: This step could be eliminated. If it is to be retained, the licensee needs to correct the typo (ATP vice AP) and change "have been performed" to are in process since upon entry to this procedure from 1210-1, there are 6 incomplete immediate actions.

c. Step 3.0: The follow-up actions do not include restoration of an EDG which did not start and energize its ES bus.

d. This procedure responds to a LOOP with a reactor trip. It does not cover LOOP in all modes (e.g. DHR; the procedure requires natural circulation verification and cooldown when the alternative of immediate DHR restoration exists). There is no other LOOP procedure.

e. Steps 3.2 & 3.3: Since restoration of power to 1D and 1E requires 10 seconds after a LOOP and verification of natural circulation requires 15-30 minutes, reversing step order is more appropriate.

f. The following inconsistencies exist: Step 3.3 states EDG voltage should be between 4000 and 4300. Procedure 1202-2A lists >4100 and procedure 1203-41 lists 4000 to 4200.

g. Steps 4.1 & 4.5: The OP procedure listed in this step is incorrect. Procedure N1807, Chemistry Primary Sampling, is the correct reference.

h. Step 4.7: Typo; change section E-3 to C-3. There is no section E.

i. The cautions following steps 4.12 and 4.15 are action statements. This conflicts with writer's guide.

11. <u>1202-2A Station Blackout with loss of both Diesel Generators</u>.

a. Same comment as 10.2

b. The B emergency diesel generator breaker is labeled "2850KW". The EDG rating in the EOPs is 3MW. The licensee stated that an earlier conflict between TMI and the vendor had been resolved in favor of the utility rating but that the breaker label had not been updated. The licensee agreed to revise the label.

c. Step 3.12 should be eliminated. The portion concerning NRC notification is incorrect since NRC should be notified of E Plan implementation. The balance of the step is unnecessary. The field teams will be established as a result of E Plan implementation.

d. Step 3.14: Poor grammar makes it difficult to understand the intent of the step and substeps; e.g. "Verify the following when instrument air depletes to 60 psig the 2 hour backup air supplies; starts to switch ..." ; "... 308(C) to control ...".

e. Step 3.20.b.3: The generator emergency seal oil pump should not be secured until hydrogen venting has been completed.

f. Pressurizer heater groups 8 & 9 emergency control panels contain eight UV relays which carry obsolete tags indicating they have been overdue for calibration since 2/86.

* g. Step 3.23: The first three lines of this step are not clear. The operator is directed to restore power to the ES busses from the aux transformer if available. In the next sentence, he is directed to allow the EDG to energize the ES bus.

h. Step 3.23: The fourth line of this step should be a conditional statement, e.g., "WHEN ES power is restored, restore makeup flow ..."

i. The procedure does not restore DC powered equipment (e.g.step 3.26: requires computer point information although computer power has not been restored from 3.20; step 3.28 RC pump restart is made without the protection normally afforded by the DC lube pump).

j. Step 3.29.i: Wording should be clarified (e.g. "Pressurizer heaters refer to EP 1202-29 for transfer of groups 8 or 9 if offsite power is not available 0.126MW.").

k. Steps 4.1: The OP procedure listed in this step is incorrect. Procedure N1807, Chemistry Primary Sampling, is the correct reference.

l. The team concluded that step 4.19 and 4.20 were incorrectly sequenced. Step 4.19 requires maintenance of present plant conditions and 4.20 requires systematic restoration of aux building ventilation, spent fuel cooling, and "additional support systems".

m. Attachment 1 provides a list of outboard containment isolation air operated valves which have motor operated inboard isolation valves. In a blackout, the motor operated valves fail as is; therefore these air valves are verified closed to ensure at least single valve isolation. The procedure does not provide air valve fail position on loss of air.

12. <u>1202-08 CRD Equipment Failure - CRD Malfunction</u>

a. General: The procedure does not address the malfunction of a rod group such as the recent Davis-Besse event. The licensee has committed to upgrade the procedure for cases where more than one rod malfunctions.

b. Step 3.B.9.b. The motor output fuses, blown fuse indicating lamps are not labeled as to which three lights are associated with which rod.

c. Step 3.1.E. Symptoms - Most of the other emergency procedures supply the actual value that the alarm is set at. No alarm values are provided in this step.

d. Step 3.E.3. The labeling on the local operators for the NR-V-10s needs to be enhanced to note that the motor operators are deenergized for Appendix R concerns.

13. 1202-9A Loss of "A" DC Distribution System

a. Step 3.5: Step 3.6B of 1202-9B, the equivalent to this step, requires Shift Supervisor's direction prior to attempting to restoring power. The licensee should determine if shift supervisor's direction is required prior to accomplishing this step.

b. Step 3.8: The caution on pg. 21 of OP 1107-2 prohibiting battery cross tie while critical appears to apply. Determine applicability and if appropriate insert that caution in this procedure.

c. Note before step 3.10: This note is identical to the sum of the two notes preceding step 3.12 of procedure 1202-9b. The latter presentation is more intelligible.

d. Step 3.10: Line one should be revised to "WHEN DC power (battery and chargers) is restored, "as is the case in step 3.12 of 1202-B.

14. 1202-9B Loss of "B" DC Distribution System

a. Step 2.0 A 11 & 12: These two steps indicate that heater drain pumps 1A and 1C receive a trip on loss of the B DC distribution bus and that pump 1B will not start but will remain running if running at the time of the power loss. The team recommends that the licensee review the feasibility of shifting either 1A or 1C pump control power supply to the A DC distribution bus so that loss of a single DC bus will not result in a loss of all heater drain pumps if pump 1B was off at the time of the loss.

b. Step 3.8 and 3.8.A: Typo; change "if" to "IF" in the second line of 3.8 and within the parentheses in 3.8 A.

c. Step 3.9: The caution on pg. 21 of OP 1107-2 prohibiting battery cross tie while critical appears to apply. The licensee should determine applicability and if appropriate insert that caution in this procedure.

d. Steps 3.9 and 3.10: The equivalent steps in 1202-9A, steps 3.7 & 3.8, are reversed and appear to be correctly sequenced. The licensee needs to verify the proper sequence and apply it in both procedures.

15. 1202-11 High Activity in Reactor Coolant

a. Step 3: The procedure directs the operator to classify the casualty per an excerpt from the Emergency Classification procedure. The level of classification depends on the "NRC Damage Code."

Unusual Event:	Damage Code < 3
Alert:	3 < Damage Code < 7
Site Area:	7 < Damage Code

The classification does not address what level should be announced if the damage code equals 3 or 7.

b. Step 9: Reword: "Reduce activity by degas (OP 1102-12, Hydrogen Addition and Degasification) and/or increased letdown flow."

16. 1202-12 "Excessive Radiation Levels"

a. Step 1.0.a: The high radiation alarms for IWTS-3-5 and IWF2-2-5 do not lead the operator to this procedure.

b. General: On the H&V panel, some of the fans are labeled with an operator aid tag of "RM-_-_ " or "ESAS" but many of the fans are not labeled.

17. 1202-17 Loss of Intermediate Cooling System

a. Step 1.4: Change the Hi Alarm to agree with the setpoint procedure. The licensee will verify which is correct.

b. Step 1.5: The setpoint in the procedure (12") is not consistent with 1101-2 (8").

c. Step 1.6: The setpoint in the procedure (8") is not contained in 1101-2.

d. Step 3.6.A: The "normal" reading in the control room was 34# Update the referenced pressure indication to agree with the pressure as read in the control room.

18. 1202-29 Pressurizer System Failure

a. Section B, Steps B.2.A.2 & B.2.B.2: There is no indication in the control room of the position of the pressurizer spray valve.

19. 1202-30 Earthquake

a. 3.0 Step 2a: AH-E-108 is labeled "Mod-Comp AC unit."

b. 3.0 Step 2b: Security has keys to "master locks" for FD-48/49. Need to note that security has the keys.

c. Step 3.0.2.e: Halon can be actuated in the Computer Room also. Note this in the step after control room.

d. Step 3.0.4: How is the flow path opened? The EF-V-8 valves have been blocked open. The procedure needs to specify which manual valves to check or verify to establish proper flow and how flow is verified.

20. 1202-31 Fire

a. General Comment: This procedure is accurate, but the sheer volume (162 pages) makes it unwieldy. This procedure consists of 11 pages of emergency instructions and the rest is appendices listing equipment operational concerns for every fire zones/area.

21. 1202-32 Flood

a. References

1. Phone Numbers 1.2: The phone number 782-2291 is for Weather Service Administration, not weather forecast. The correct number for forecast information is 782-2254.

2. Appendix I: This appendix illustrating gates and seals is handwritten and poorly reproduced.

3. Appendix V: This is an unnecessary duplication of emergency flood procedure and is not referenced in the text of the procedure.

22. 1202-35 LOSS OF DECAY HEAT REMOVAL SYSTEM

a. Step 2.B.2: Move step 2.B.9 to immediately follow step 2.B.2.

b. Step 2.B.6: Add the word "local" before the word suction or clarify where to read suction head.

c. Step 2.B.6: The instructions in parentheses, "start alternate decay heat removal, decay heat closed cooling and decay heat river pumps" Place the instruction in a column format.

d. Step 2.B.6: After the step, add a new step to open or throttle open DHV-4A and B as necessary to restore cooling to the RCS. The new step is necessary to establish flow.

e. Step 3.A: Establish another method of filling the RCS system. The normal procedure, which is instructed to be used to fill the RCS,

uses WDL-P7A, B or C, which rated at approximately 140 gpm. Depending on the time after shutdown, a flow rate of 140 gpm would not be enough to remove the decay heat being generated. Also the time required to initiate the procedure is a critical factor.

* f. Step 3.A: Add a step that would clear the necessary tags and align the make up system for operation. Seal Injection is necessary for RCP starting and operation.

g. Step 3.A.4: Change the referenced procedure from 1102-16 to 1102-11 Enclosure 2. The referenced procedure number is wrong.

h. Step 3.B.2: Change the procedure order to make step 3.B.8, "Re-establish containment integrity ---" become step 3.B.2.

i. Step 3.B.3: Add a new step evacuating all unnecessary personnel from containment.

j. Step 3.C.3: Add a new step evacuating all unnecessary personnel from containment.

k. Step 3.C.4.d: Add a new step instructing the operator to continuously monitor the decay heat flow. Once the water level is approximately seven (7) feet above the vessel flange, corresponding to approximately three (3) psig at the flange, the Reactor vessel head will start to lift if all of the studs are removed. If, even one stud is in place, the head will not lift, and water level and pressure will increase in the RCS. The cold over pressure protection per TS is 485 psig. The dead head of the Decay Heat Pumps is approximately 200 psig. Decay Heat flow will decrease as RCS pressure increases until at 200 psig flow will stop and core heat up will increase.

l. Step 3.C.4.d: Add a new step giving "guidance" for minimum flow on decay heat for the given condition and a method for increasing the flow; ie. open the PORV.

* m. Step 3.C.5.b: Add a new step before 3.C.5.b instructing the operator to clear the tags on the Make Up Pumps and HPI valves. The pumps and valves can not be operated with out power.

* n. Step 3.C.6: Add the following statement to the end of the step, "Per the following step".

o. Step 3.D.1: Add a new step to evacuate all unnecessary personnel from containment.

p. Step 3.D.1: Add a new step to set containment integrity.

q. Step 3.E.4: Add a new step to evacuate all unnecessary personnel from containment.

* r. Step 3.E.5: Add a new step to clear the tags on the Make Up Pump and the HPI Valves. Have to remove the tags to start the pump and open the valves.

s. Step 3.E.3: Add a new step instructing the operator to return to the action of step 3.D if in the performance of the following steps, the water starts to overflow the reactor vessel flange into the seal cavity area.

t. Step 3.E.4: Move the step to become step 3.E.2

u. Step 3.E.3: Add a new step to evacuate all unnecessary personnel from containment.

v. Step 3.E.5: Move the CAUTION after step 5 to before step 5.

w. ATTACHMENT 1 step A.4.e: Insert the word local between the words "minimum suction".

x. ATTACHMENT 1 Step B.1: Add a step to clear the tags on the applicable Make Up Pump.

y. ATTACHMENT 1 step C.4: Insert the word local between the words, "Check suction" and "Record pressure", or clarify were to read suction header.

z. ATTACHMENT 1 NOTE: after step C.6: The note contains an action step. Remove "While on recir check DH-1 FI 1/2 to determine if it will respond to flow" and make it a separate step.

aa. ATTACHMENT 1 NOTE: after step C.6: The referenced flow indicators DH-1 FI 1/2 are wrong. They should read DH-FI-802A and FI-803A.

ab. ATTACHMENT 1 step C.9: Insert the phrase "as read on MU 24 FI" between "is and >".

ac. ATTACHMENT 1 step C.9: After the note insert the phrase "MU 24 FI" between the words "Record and flow".

ad. ATTACHMENT 1 step C.9: The sentence before step 10 inset the phrase "802A or 803A" in place or "1/2".

ae. ATTACHMENT 1 step C.11: Insert the phrase "MU 24 FI" between the words "Record and flow".

af. ATTACHMENT 1 step C.11: In the second line, remove FI-1 and insert "FI-802A or FI-803A"

ag. ATTACHMENT 1 C.11: In the third line, insert the word "local" between the word "pump and suction". Change the engineering units from gpm to psig.

ah. ENCLOSURE NO 1A and 1B: Move the columns for the valve, position, and the initial closer together. With the present spacing it is easy to make an error in the proper valve position.

23. 1202-36 Loss of Instrument Air

a. Step 3.11: Make the note a step that precedes step 11.

b. Step 3.15: This step contains more than one action.

24. 1202-38 Nuclear Services River Water Failure

a. Step 3.5.e.3: The column heading "Annunciator alarm requiring manual trip of RC pump" is the last sentence at the bottom of page 4, and the actual alarm values start at the top of page 5. Place the column on the same page as the alarms.

* b. Step 2.13: Add a step to reestablish Letdown if isolated. Licensee will evaluate the wording.

25. 1202-40 Loss of ICS Hand and Auto Power

a. Step 1.4: Change the wording to agree with the alarm wording on the alarm window.

b. ATTACHMENT 1 steps 2 and 3: Combine step 2 and step 3 to read: "Restore auto power prior to hand power using OP 1105-6".

26. 1202-41 Total or Partial Loss of ICS/NNI Hand Power

a. Steps 1.1 , 1.4.b, and 1.4.c: Change the wording to match the actual alarm window.

* b. Step C.1: Change substeps a thru e to "if/then" statements. In the If column change to read " If ---- in manual"

* c. Step C.7.d: Change the set to read "Return ICS to auto control per OP 1105-4 Appendix VII to clarify action.

27. 1202-42 Total or Partial Loss of ICS/NNI Auto Power

a. Step 1.1: Change the name given in the procedure for the alarm to agree with the wording on the alarm window.

b. Step 3.6: Add a new step 3.6.f to read "f. Restore ICS control to Auto Per 1105-4 Appendix VII, if applicable".

c Table IIA & IIB: Go thru all of the alarm windows listed and make the titles listed in the procedure agree with the name listed on the alarm window. Several titles listed in the procedure are wrong.

28. 1203-1 Load Rejection

a. Caution before step 3.0: The loss of the other feed pump will cause either a LOOP or a blackout, depending upon whether one or both EDGs start and energize the busses. The licensee needs to include both alternatives, the LOOP and the blackout.

b. Caution before Step 3.0: The caution does not apply to any step within this procedure. If this caution is to be maintained, then an applicable step needs to be added.

c. Note before 3.8: This note should be revised to recognize that either a LOOP or a blackout could result from a turbine generator trip at this point.

29. 1203-5 High Cation Conductivity in the Condensate and/or Feedwater System

a. Steps 1.6/7/8: These alarm windows do not refer the operator to the procedure.

b. Steps 1.4/5/6/7/8: The title of the Alarm Response Procedures are not consistent with the title contained in the procedure.

c. Step 3.1: Grammar; delete "are".

d. Step 3.1D: Grammar; change "and/or" to "and".

e. Steps 3.1 & 3.2: Substeps within these two steps require the operator to isolate one side of the main condenser. In so doing, one side of each of the auxiliary condensers is also isolated. The operator is not provided this information.

f. Step 3.4: Step 2.0B reactor trip was conditional upon conductivity >5.0 as confirmed by chemistry. This step requires verification of reactor trip (e.g. if not already tripped, trip) based upon conductivity alone. Determine whether chemistry confirmation is desired and revise the procedure if appropriate.

g. The procedure does not provide actions for the full spectrum of potential CE-6/7 or CE-6A readings. Responses are provided for values of 0.5-1.0, >1.0 during the first 24 hours, and >5 at any time. Responses for readings between 1.0 and 5.0 after the initial 24 hours are not addressed. The error is probably caused by an incorrect upper limit Of <1.0 in line two of step 5.

h. Step 3.6: Reword: "If CE-12, Sixth Stage Drain Tank indicates >1 umho/cm, then follow the action below for that respective point:"

i. Steps 3.7 & 3.8: These two steps would be more appropriate substeps of the above lead-in condition.

j. Step 3.9: Reword: "If PRF-1-4 alarms, ..."

k. Step 3.13: Reword: "As necessary, secure a feedwater pump (OP 1106-3):"

l. Step 3.13.a: Delete step 3.13.a and renumber accordingly.

m. Step 3.13.b: Reword: "Close CO-V-9A(B) and CO-V-374A(B)."

n. Steps 3.14 & 3.15: Move these steps to the end of the procedure and made Attachments. Add a note to steps 3.1.c and 3.2.b referring the operator to the attachments.

o. For consistency add an attachment(s) to describe the process for isolating an auxiliary condenser.

p. Page 8.0: The "Discussion" does not belong in the procedure. The objective is already contained at the beginning of the procedure.

30. 1203-15 Loss of R. C. Makeup

a. Step 1.3: This step gives as an entry condition "MU Pump discharge header pressure high (2850 psig) ...". The normal reading on MU2-PI is about 3100 psig.

b. Step 1.0: The Alarm Response Procedures associated with the alarm windows associated with the entry conditions of this procedure do not refer the operator to this procedure.

c. Note before Step 3.1: The note discussing the event classification is not consistent with format normally used. That is, the operator is not referred to 9471-IMP-1300.01, Emergency Classification procedure.

d. Step 3.2.d: Reword: "...so seal water at the bearing is changing less than 1°F/min. ..."

31. 1203-16 Reactor Coolant Pump/Motor Malfunction

a. Step 1.1 Symptoms: To be consistent, each symptom should indicate the particular annunciator window, e.g., 1.1.a (E-1-3), 1.1.5 (E-1-4).

b. Step 1.2.B.1.a: List Valve number (e.g., MU-V-33A-D).

c. Step 2.1 Symptoms: List the appropriate annunciator window location. 2.1.a (F-1-5).

d. Steps 2.0 and 3.0: Both of these sections discuss loss of systems other than that noted in the title. Specifically, 2.0 "Loss of Seal Inj" discusses loss of IC cooling. 3.0 "Loss of NS, IC Systems" discusses loss of seal injection. It appears that a separate procedure is needed for a combined loss of seal injection and cooling water to the pump motor.

e. Step 3.1.1.a: Computer or annunciator? Need to list window location or computer point.

f. Step 3.1.2.d: Units are not provided.

g. Steps 3.2.B.2.: Some of the values are above the alarm point and some correspond to the alarm point. Confirm that the inconsistency is intended.

h. Step 6.1.b.: The 186 value cited here was 190 in Step 3.1.1.b. A value of 185 is used in 6.2.B.2.

i. Step 6.3.2: The implication is that more than one pump may be "secured" with a corresponding power reduction of 75%.

32. <u>1203-19 River Water System Failure</u>.

a. General Comment: The secondary river (SR) and decay heat river (DR) systems are not related or interdependent except for common suction point which is not discussed in this procedure. Response to loss of either system involves vastly different concerns. Even the alarm symptoms in 1.0 do not apply uniformly to loss of both systems. The operator, in responding to loss of either system, must pick and choose the appropriate steps in section 3.0 to respond. Additionally, the nuclear river (NR) water system failure procedure is independent.

b. Title: The Title is incorrect, as the DR/SR are only two of four river water systems.

c. Step 1.0.8: "Excessive Water Accumulation" is the only common symptom for loss of both systems.

d. GENERAL: There are many inconsistencies in the nomenclature used in specifying the system, (e.g., river water, DR, decay heat river, DH river water, decay heat river water), however, are refer to the same system.

33. <u>1203-20 Nuclear Services Closed Cooling System Failure</u>

a. Section 1.1 Symptoms: The Symptoms "480 VE.S. Motor Trip" (C-3-7) and "480 VE.S. Motor Overload" (C-3-6) may also indicate a possible

loss of a nuclear services closed cooling (NSCC) pump. It is not clear that a normal plant shutdown can be conducted under the conditions which may exist.

b. Note following Step 3.4: 1203-16, Item 3.2.B.2.b uses 185F on radial bearings and states the operator is to reduce power to 75% and then trip the pump.

34. 1203-21 Secondary Service Closed Cooling System Failure

a. Steps 1.1 & 1.2: The Alarm Response Procedure does not refer the operator to this procedure.

35. 1203-28 Post-Accident Hydrogen Purge

a. Step 3.4.10: The procedure directs the operator to 9100-ADM-4212.06 for re-evaluation of activity in the reactor building; but, there is no procedure with this number or title.

b. Attachment I, Section 1: There are two spectacle flanges installed near LR-V-2/3, the procedure does not address that they will need to be reversed.

c. Attachment I, Section 3(pg E1-2): The procedure directs the operator to place the damper in the closed position. The operator was not able to determine how to perform this function.

36. 1203-34 Control Building Ventilation System

a. Step 1.1: Alarm Annunciator is (C-2-1).

b. Step 1.2.B: This step requires verification of AH-D-28, 37, and 36. AH-D-28 has no local PI and AH-D-36/37 must be verified by a visual exam which involves an arduous effort.

c. Step 1.3.2: 37,351 ±10% is not readable. Flow recorder is in increments of 1,000 scfm.

d. Step 1.3.2: Place the Note on Page 4.0 before Step #1.

e. Step 2.1. Symptoms: Add H&V panel locations.

f. Step 4.2.A.2: The "ATC Compressed Air System" is actually the "HMV Instrument Air Compressor".

g. Appendix A, page E1-1: AH-E-22A/B and the fan name needs to be added to this list.

h. Enclosure 1, Item N. (11) duct converters: These were not located. Also, they are probably "connectors" not "converters".

i. Enclosure 1, page E-2-2 Caution: Place the "caution" after step 4.2 prior to Step 4.1.

37. 1203-41 Low System (Grid) Voltage

a. Step 1.0: The alarm response procedures do not direct the operator to this procedure.

b. Caution before Step 2.2.2: Place the caution before step 2.2.1.

c. Step 2.2.3: The procedure directs specific actions depending on whether or not the current readings are in the "danger zone" or in the "caution zone." The ammeters have labels next to them with terminology of "Overload" and "Longtime Limit".

d. Step 3.0 Objective: Typo; insert "to" between transformer and restore on line 2.

e. Step 3.6: To remain consistent with other procedures add "and leave running continuously" to the first sentence.

f. Step 3.8A: EDG voltage is listed as 4000-4200V. In 1202.2 step 3.3, EDG voltage is listed as 4000-4300 and in 1202.2A it is listed as >4100. Determine the correct value and apply it to all EOPs.

g. Note following step 3.9: Under these circumstances, a main generator trip will cause either a LOOP or a blackout, depending upon whether one or both EDGs start and energize the busses. Include both alternatives, the LOOP and the blackout.

38. 1102-12 Hydrogen Addition and Degassification

a. Step 3.4.1.2.1.A: This step requires the operator to open MU-V-226. The operator was not able to positively locate the valve in the plant; however, he knew the approximate location, above some ventilation ductwork.

(1) Provide lcoal notation of location and operation of MU-V-226.

(2) While looking for MU-V-226, a valve with a chain operator was noticed in the general area with no valve number readily visible.

39. 1104-62 Hydrogen Recombiner

* a. Table 2: This table directs the operator to set Timer T-2, the operator could not find the timer. Later it was found to be located behind a cabinet door.

40. N1831 Post-Accident Atmospheric Sampling

a. Chemistry has performed actual samplings of the reactor building environment per this procedure.

b. Step ???: The procedure directs the chemist to line up the air bottle if necessary; recommend a note be added that Instrument Air is the normal driving head for the sample.

41. 9471-IMP-1300.01 (Rev.0) Emergency Classification

a. EAL 6.1 classifies a LOOP with EDGs (plural) operating as an Unusual Event and a LOOP with neither EDG operating as an Alert. The procedure does not include the intermediate case of a LOOP with only one operating EDG. As a result of this discontinuity, during a simulator drill the shift supervisor classified a LOOP with one EDG operational as an Alert.

APPENDIX C

DIFFERENCES BETWEEN PSGs AND ATPs

This appendix contains comments and observations on deviations between the plant specific technical guidelines (PSG) contained in TRD-517 and the existing revisions of the ATPs. The bases for these deviations has not been documented by the licensee. The licensee has agreed in each case to evaluate the comments and take appropriate action. Additionally, the licensee has committed to establish a formal program to ensure that safety significant changes to the ATPs will be reflected in TDR-517.

COMMENTS AND OBSERVATIONS

1 General Observations

* a. In several instances, the team noted that the ATP and the PSG, Rev.1 entries were in agreement; however, the particular steps were missing from PSG, Rev.2, the latest version of the Plant Specific Guidelines (e.g. ATP 1210-6 steps 1.1 regarding SCM verification and high point vent closure).

2. 1210-1, Reactor Trip

a. Step 3.4 and 3.5: These steps instruct the operator to reduce pressure and then verify RCS pressure stabilizes; but, the steps are reversed in PSG TDR-517 Revision 2. The steps in 1210-1 are correct, but, there is no justification why the steps were changed.

b. Step 3.12: The instruction refers the operator to the 1210-10 guides for operating containment isolation valves; but, the PSG refers the operator to the large LOCA procedure. Step 3.12 in 1210.1 is correct. Justification for changing this step is not provided.

3. 1210-4, Lack of Primary to Secondary Heat Transfer

* a. There are many instances of disagreement between the procedure and the PSG, for example:

Step 1.2.2: The PSG directs use of the main FW or the condensate pumps. The procedure does not include the condensate pump alternative.

Step 1.5: The order and some of the actions differ from those of the PSG.

Step 2.7: The PSG does not transfer to 1210-1.

Several more after step 2.10.

b. Followup actions: The PSG states that actions are keyed to the SBLOCA which causes an interruption of loop flow. The procedure does not. Although this is a logical entry, it is not the only entry; e.g. entry may result from loss of feed with subsequent restoration. The licensee should review this procedure to ensure that it responds for all entry conditions.

4. 1210-5 "OTSG Tube Leak/Rupture"

a. Step 3.5: After this step in TDR-517, there is a caution that states "When the turbine is tripped it may be necessary to take manual control of turbine bypass valves to maintain secondary pressure below the main steam safety valve setpoints." This caution does not appear in 1210-1.

b. Step 3.11: Minimize the steaming of the affected OTSG, especially if this procedure has been entered without the presence of a reactor trip.

c. Step 3.20: The designations for the MS-V1 valves is not correct in TDR-517.

* d. Step 3.29: TDR-517, page 27, includes a step to isolate the affected OTSG when on DH Removal; but 1210-5 does not include this step. Nor could it be found in the procedure for DH Removal System, 1104-4.

e. General Comment: The TMI approach to control of a SGTR involves potential steaming of the OTSG during cooldown, as opposed to isolating the OTSG to stop releases to the environment. This is consistent with one of the options provided in the generic B&W Owners' guidance contained in the Technical Basis Document (TBD). The TBD guidance and the TDR-517 information on this topic are both under NRC staff review, and the approach being followed by TMI has been neither approved nor disapproved by the staff. The team has not addressed this issue, and nothing resulting from this inspection may be taken as indicating an NRC staff approval of the TMI approach.

5. 1210-6 Small Break LOCA Cooldown

a. Step 2.2: The PSG addresses the case of only one LPI in operation. The procedure does not.

b. Step 2.16 last sentence: To be consistent with the PSG and format instructions, this should be contained in a caution statement.

c. Step 2.20: The PSG shift to piggy back takes place at 36" in the BWST, not 76" as in this step.

d. The procedure concludes without the PSG step concerning PORV closure and drawing a bubble in the pressurizer.

6. 1210-7 Large Break LOCA

a. PSG Step 2.3: The PSG step 2.3 states that reactor building spray should be 1,500 gpm. The correct flow is 1300-1400 gpm.

b. PSG Step 2.5: This step uses the wrong units (psig) and should be changed to gpm. The 1210-7 procedure step is correct.

c. PSG Step 2.3. Swap over to RB sump specified at 6'4" in ATP but 3' in PSG.

d. PSG Step 2.17.1: The ATP specifically verifies flow from the sump, but the PSG does not identify what system to use to verify flow.

7. 1210-8 RCS Superheated

a. Step 1.3: The 100 degrees was contained in the Rev.1 version of the PSG but was eliminated in Rev.2.

b. Step 2.5.4: The transfer is correct in the procedure but wrong in the PSG.

8. 1210-9 HPI Cooling - Recovery from Solid Operations

a. The PSG does not include steps 2.1 & 2.2.

b. Step following 2.13.5 and step 2.14: The ATP verification of SCM and transfer to 1210-6 is out of sequence when compared to the PSG.

c. Step 2.13.6: PSG steps 15 & 16 discuss expansion and heatup rate and are not included in the EOP.

9. 1210-10 Abnormal Transients Rules, Guides and Graphs

* a. Step 1.4.3: "If one hour has passed since reactor trip, lack of SCM does not prevent RCP restart." This is inconsistent with TDR-517 which does not address this contingency. The licensee states that this requirement was included in revision 1 of TDR-517 but was dropped from Revision 2.

b. Step 1.6.3: The words "operate range" need to be added to TDR-517.

APPENDIX D

LIST OF ABBREVIATIONS

AC	Alternating Current
ADV	Atmospheric Dump Valves
AFW	Auxiliary Feedwater
AP	1203 Series of Abnormal Procedures
APSR	Axial Power Shaping Rods
ATOG	Abnormal Transient Operating Guidelines
ATP	1210 Series of Abnormal Transient Procedures
B&W	Babcock & Wilcox
BWST	Borated Water Storage Tank
CFR	Code of Federal Regulations
CRD	Control Rod Drive
CST	Condensate Storage Tank
DC	Direct Current
DCN	Design Change Notice
DHR	Decay Heat Removal
DPM	Decades per Minute
EAL	Emergency Action Level
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedures as described in RG 1.33
EP	1202 Series of Emergency Procedures
EPG	Emergency Procedure Guidelines
ES	Engineered Safeguards
ESAS	Engineered Safeguards Actuation Signal
FW	Feedwater
GPM	Gallons per Minute
GTG	Generic Technical Guidelines
HP	High Pressure
HPI	High Pressure Injection
ICC	Inadequate Core Cooling
ICS	Integrated Control System
I&E	Instrument & Electrical
IFI	Inspector Followup Item
INPO	Institute of Nuclear Power Operations
KV	Kilovolts
LCO	Limiting Condition of Operation
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LPI	Low Pressure Injection
MFIV	Main Feedwater Isolation Valves
MFW CV	Main Feedwater Control Valve
MSIV	Main Steam Isolation Valve
MSI	Main Steam Line Isolation
MOV	Motor Operated Valve
MW	Megawatts
MPC	Maximum Permissible Concentration
NLO	Non-licensed Operator
NNI	Non-Nuclear Instrumentation
NOUE	Notification of Unusual Event

NRC	Nuclear Regulatory Commission
NSCC	Nuclear Services Closed Cooling System
OG	Owners Group
OP	Operating Procedure
OTSG	Once Through Steam Generator
PGP	Procedure Generation Package
PORV	Power Operated Relief Valve
PSG	Plant Specific Guidelines (TDR 517 Rev 2
PSIA	Pounds per Square Inch Absolute
PSIG	Pounds per Square Inch Gauge
P/T	Pressure/Temperature
PWG	Procedure Writers Guide
PZR	Pressurizer
QA	Quality Assurance
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RCSI	Reactor Coolant System Inventory
RG	Regulatory Guideline
RPS	Reactor Protection System
RV	Reactor Vessel
RX	Reactor
SER	Safety Evaluation Report
SFAS	Safety Features Actuation
SG	Steam Generator
SGTR	Steam Generator Tube Rupture
SPDS	Safety Parameter Display System
SRO	Senior Reactor Operator
SS	Shift Supervisor
STA	Shift Technical Advisor
SW	Service Water
TBD	Technical Basis Document
TMI	Three Mile Island
TS	Technical Specifications
(U)FSAR	Updated Safety Analysis Report
UV	Under Voltage
V&V	Validation and Verification

APPENDIX E

REFERENCES USED IN TECHNICAL ADEQUACY REVIEW

1. "Oconee Nuclear Station Unit 3, ATOG, Abnormal Transient Operating Guidelines," 74-1123297-00 with updates resulting from staff review, Babcock & Wilcox Nuclear Power Generation Division, March 23, 1982.

2. "Emergency Operating Procedures, Technical Bases Document, "74-1152414-01, Babcock and Wilcox Nuclear Power Division Technical Document, March 7, 1988 (date of latest revision).

3. Lou Lanese, "TMI-1 Plant Specific Guidelines Derived from ATOG," GPU Nuclear Technical Data Report, TDR-517 Revision 1, signed May 14, 1984, approved for external distribution June 25, 1984. Transmitted to the NRC by GPU Nuclear letter to John F. Stolz dated June 29, 1984.

4. Lou Lanese, "TMI-1 Plant Specific Guidelines Derived from ATOG," GPU Nuclear Technical Data Report, TDR-517 Revision 2, signed June 3, 1988, approved July 1, 1988, approval for external distribution box blank.