APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-382/88-18 Operating License: NPF-38

Docket: 50-382

Licensee: Louisiana Power & Light Company (LP&L)
142 Delaronde Street
New Orleans, Louisiana 70174

Facility Name: Waterford Steam Electric Station, Unit 3

Inspection At: Taft, Louisiana

Inspection Conducted: July 6 - 14, 1988

Inspector: J. P. Stewart, Team Leader, Region IV — Date: 8/9/88

Team Members: J. O'Brien, Senior Reactor Inspector, Region V
L. Defferding, Licensing Examiner
C. Tolbert, Human Factors Specialist
P. Bibb, Resident Inspector, St. Lucie
W. Smith, Senior Resident Inspector, Waterford 3

Approved: J. E. Gagliardo, CE EOP Manager, Region IV — Date: 8/9/88

Inspection Summary

Inspection Conducted July 6-14, 1988 (Report 50-382/88-18)

Areas Inspected: Special team inspection of Waterford 3 Emergency Operating Procedures (EOPs) including the following areas:

- Basic EOP/CEN-152 comparison
- Technical adequacy review of the EOPs
- Control room and plant walkdown
- Simulator
- EOP ongoing evaluation
- Human factors related guidance

Results: No unsafe operational conditions and no violations or deviations were identified. Although several technical and human factor weaknesses were found, the emergency operating procedures were found to be adequate to support continued safe operation of the facility. The licensee has committed to review the identified weaknesses and the appropriate corrective actions to resolve them.

Open Items Summary: During this inspection, eight open items were identified which will require followup. The open items include: (1) correction of technical deficiencies identified in the Emergency Operating Procedures (EOPs); (2) incorporation of instrumentation safety margins into the EOPs, when the CEN-536 study identifies the appropriate margins needed; (3) validation of all EOP revisions with a normal operating shift; (4) correction of the plant equipment deficiencies associated with the implementation of the EOPs; (5) upgrading the safety function recovery procedure training programs (simulator and classroom); (6) upgrading of EOP evaluation program elements for providing feedback of operator concerns and difficulties with the EOPs; (7) incorporation of operator's ability to perform during emergency or abnormal conditions in annual performance appraisal; and (8) upgrading of quality assurance oversight of EOP development and implementation.

DETAILS

1. Persons Contacted

Principal Licensee Employees

*R. P. Barkhurst, Vice President, Nuclear Operations
N. S. Carns, Plant Manager, Nuclear
D. P. Packer, Assistant Plant Manger, Operations and Maintenance
D. E. Baker, Operations Assistant
L. W. Laughlin, Licensing Engineer
R. S. Starkey, Operations Superintendent
S. A. Alleman, Quality Assurance Manager
J. G. Hoffpauir, Assistant Operations Superintendent
G. G. Davie, Shift Supervisor
D. P. Clark, Operations Training Supervisor
C. Boudreaux, Training Supervisor
W. L. Smith, Simulator Supervisor

*Denotes those attending the exit meeting on July 14, 1988.

The inspectors also contacted other licensee employees during the course of the inspection, including training instructors, shift supervisors, control room supervisors, reactor operators, plant equipment operators, and procedure writers.

Also in attendance at the exit meeting on July 14, 1988, were the following NRC and NRC contracted staff personnel:

J. Jaudon, Deputy Division Director, Region IV
G. Lapinsky, Jr., Human Factors Branch, NRR
P. Stewart, CE EOP Team Leader, Region IV
J. O'Brien, Reactor Inspector, Region V
C. Tolbert, Human Factors Engineer, SAIC
L. Defferding, License Examiner, Battelle Northwest Labs
W. Smith, Senior Resident Inspector, Waterford 3

2. Waterford 3 (W3) EOP/CEOG CEN-152 Procedure Comparison (25592)

A comparison of the W3 Emergency Operating Procedures (EOPs) and the Combustion Engineering Owners Group (CEOG) Emergency Procedure Guidelines (EPGs) CEN-152, Revision 2, was conducted. The objective of this review was to ensure that the licensee had developed sufficient procedures in the appropriate area to cover the broad spectrum of accidents and equipment failures that must be considered. All of the licensee's EOPs are listed in Appendix A of this inspection report. The inspectors reviewed the licensee's EOPs and noted that procedures were implemented in accordance with the CEOG recommendations. In addition, the licensee implemented Emergency Operating Procedure OP-902-005, Revision 2, "Degraded Electrical Distribution Recovery Procedure." The purpose of this procedure was to check that a degraded electrical distribution has

occurred and adequate core cooling capability exists following a loss of AC power to electrical busses while maintaining other safety functions through normal methods.

The comparison included reviews of the licensee's documentation and interviews with personnel to verify that any deviations from CEN-152 were justified. Other minor discrepancies and human factors deficiencies were identified in the paragraphs below and in the appendices to this inspection report.

The inspector determined that the licensee had adequately developed plant specific EOPs to implement CEN-152, Revision 2. The changes from CEN-152 recommendations were reviewed with the bases established and were documented by the licensee.

3. Independent Technical Adequacy Review of the EOPs (25592)

The W3 EOPs listed in Part I, Appendix A, were reviewed to ensure that the procedures were technically accurate and incorporated the guidelines of CEN-152, Revision 2.

This review verified that the CEOG step sequence was followed, except for the minor deficiencies identified in Appendix B of this report. In each case the licensee committed to reorder the step sequence to be in agreement with CEN-152, Revision 2. The team determined that the licensee's responses in each case were adequate.

The review also verified that transfer between procedures was well defined and appropriate for procedures performed concurrently, that minimum staffing was met, and that notes and cautions were used correctly. Each deviation from CEN-152 was reviewed to ensure that safety significant deviations were reported to the NRC as required, that deviations warranted by specific plant design were incorporated, and prioritization of accident mitigating strategies were correct.

The team determined that, in general, the EOPs adequately incorporated the procedure guidelines of CEN-152, Revision 2. The summary of the findings and observations of the W3 EOPs is as follows:

- Entry/exit points to the W3 EOPs were clearly stated and could be followed by trained reactor operators. The licensee agreed to incorporate minor additional entry condition clarifications to be in agreement with CEN-152 (as noted in Appendix B).

- Notes within the EOPs were generally clear and appropriately located in the EOPs.

- The CEN-152 prioritization of the accident safety function investigation hierarchy was maintained in the EOPs.

- The plant specific values for plant protection system setpoints (e.g., SIAS, CIAS, CSAS) were consistent with the plant design values.

During the EOP review, the team identified a number of technical concerns in the EOPs, and they are listed along with the licensee's responses in Appendix B of this report. The identified concerns focused in two areas: (1) steps out of sequence with the step order specified in the CEN-152 guidelines without providing technical justification for the difference in sequence; (2) clarification of the preferred instrumentation to be utilized to verify a plant parameter. During the inspection, the licensee either provided the clarification to the EOP deviations from CEN-152 or acknowledged the technical deficiencies, which were identified by the inspection team. The licensee agreed to correct EOP deficiencies as required to be consistent with CEN-152 in the next revision to the W3 EOPs. The team determined that the licensee's resolutions were acceptable. The licensee's correction of the deficiencies identified in Appendix B will be followed up after the issuance of the next revision of the EOPs, which is scheduled for the first quarter of 1989. This is an open item (382/8818-01).

The team also identified that the licensee has been a participant in CEN TASK 536, which is a task for developing a methodology for determining instrument errors to be included in the appropriate EOPs for adverse containment environments. The licensee is awaiting the results of this project and will revise its EOPs accordingly. This item will be followed up after the completion of CEN TASK 536. This is an open item (382/8818-02).

The team observed that the W3 EOPs, except for OP-902-000, the emergency entry procedure (standard post-trip actions), were all in a single column format. The CEN-152 guidance calls for the utilization of a dual column format. Licensee representatives (department level) stated that they had no plans to go to the dual column format. At the exit interview, the inspection team communicated to the licensee's senior management, that although it was not an NRC requirement to use a dual column format, the licensee should consider the advantages of the dual column format, and understand why the CEOG recommended the implementation of a dual column format in the EOPs. This item is also discussed in Section 7.C. of this report.

Additional technical deficiencies identified during observation of the simulator scenarios are addressed in Section 4 of this report.

No violations or deviations were identified in the review of this program area.

4. Review of Validation Program and Independent Verification of the EOPs (25592)

As a result of the TMI-2 accident, NUREG-0899 was issued in August 1982 to establish the guidelines for the development and implementation of EOPs, which would provide the operators with directions for mitigating the

consequences of a broad range of accidents and equipment failures. Paragraph 3.3.5 of this NUREG indicated that, after development, the EOPs were to undergo a process of verification/validation to determine that the procedures were technically adequate, addressed both technical and human factors issues, and would be accurately and efficiently carried out.

The licensee provided documentation to show that their verification program met the following purposes: confirm the procedures are technically accurate and are written correctly for ease of use.

The licensee's verification program contained the following table-top reviews:

- To compare each procedure to the applicable generic and plant specific technical guidelines and to other source data such as Technical Specifications and FSAR.

- To compare each procedure against a checklist of criteria drawn from the Writer's Guide.

The licensee also provided documentation to demonstrate that the validation program met the stated purpose of demonstrating that the actions specified in the EOPs can be followed by trained operators to effectively manage emergency conditions (except as noted below). The three elements of the validation program were:

- A table-top review where control room personnel talk through the steps of the procedure.

- A control room walkthrough where control room personnel perform a step-by-step enactment of the procedure.

- Simulator exercise where control room personnel perform the procedure, including execution of control actions on a real time plant simulator. The control room walkthrough and simulator exercise used prepared scenarios. All new procedures had been validated and approved.

The inspection team conducted its own control room, simulator, and plant walkdowns of the EOPs listed in Part 1 of Appendix A of this report to ensure that the procedures were validated and verified by the licensee.

During the walkdowns, instruments and controls were verified to be correctly labeled (except for those deficiencies indicated in Appendices C and D). The team also verified that the indications referenced in the procedures were available to the operator and values were not overly specific for the available indicators. Administrative procedures were reviewed to ensure that adequate controls existed to incorporate changes to the EOPs, that the latest revision was available to the operators, and that they were easily accessible. The team found that the documentation indicated the discrepancies had been adequately

addressed and corrected, comprehensive reviews had been conducted, table-top reviews were adequate, walkdowns had been completed and documented, and human factors personnel had been involved in the program.

During the performance of simulator scenarios, the team identified several deficiencies. During the use of the functional recovery procedure, OP-902-008 E5, the inspectors noted that two independent operating crews had difficulty identifying which success path to use, from the resource assessment tree, for the loss of feed scenario with condensate pumps available. The success path, on the tree, failed to include the option to depressurize the steam generator and feed with the condensate pumps. Operating steps covering this option were included in the body of the procedure.

Path V3, Step 19.5 of this same procedure directed the operator to fully open the atmospheric dump valve in order to depressurize the steam generator so they could be fed with condensate pumps. This rapid depressurization causes a very rapid reactor cooldown.

Discussion with the plant personnel noted that the validation of the EOPs was completed by procedure writers and senior staff. This validation by highly experienced personnel caused several deficiencies to be overlooked that probably would have been identified if regular operating shifts had been used. The licensee agreed to review and correct these deficiencies and to use normal operating crews to validate all new procedure revisions. This is an open item (382/8818-03).

In addition, the NRC inspectors, during the control room simulator and in-plant walkdowns, identified the deficiencies listed in Appendix D. The licensee committed to make the appropriate procedure revisions as noted in Appendix D. The licensee's revisions of the EOPs and associated documentation for the correction of the noted procedural deficiencies in Appendix D will be followed up in a later inspection. This is an open item (382/8818-04).

No violations or deviations were identified in the review of this program area.

5. EOP Training (25592)

The inspection team assessed the adequacy of the EOP training by reviewing three areas. The first dealt with observing an unrehearsed operating crew performing the EOPs in the site-specific simulator with scenarios designed to exercise each of the EOPs. The second effort was to review the lesson plans and training records for the hot licensed and requalification operator training programs as they pertained to EOP training. Finally, interviews were conducted of a selected sample of the operations staff.

a. Simulator Scenarios

The team's license operator examiner and reactor inspector developed scenarios similar to those used for licensed operator exams and EOP training. During the performance of these scenarios with the

unrehearsed operating crew, the entire NRC EOP inspection team had the opportunity to: observe the operator's performance to validate or dismiss any concerns that may have been raised during the table-top reviews of the EOPs; assess the licensee's operating philosophy (possibly as it differs from CEOG guidance in CEN-152); assess the human factors elements (place keeping, assignment of duties, physical interference, etc.) associated with the performance of the procedures in a "real time" atmosphere; observe how the operators diagnose accident conditions and transition from one EOP to another. The team made the following observations:

- The operators exhibited adequate knowledge of the EOPs and the CEN-152 guidance.
- The operators were not familiar with the Resource Assessment Trees for the success path selection in the Safety Function Recovery Procedure (SFRP).
- The operators had difficulty in the controlling plant cooldown rate using the SFRP.
- The operators were more comfortable using the optimum recovery procedures than the SFRP.
- Other human factors observations were identified and are addressed in Section 7 and Appendix C of this report.

b. Formal Training Programs

Lesson plans and simulator scenarios used for EOP training were reviewed to determine whether the training covered the technical basis for the procedure, as well as the structure and format of the EOPs. The lesson plans, procedures, and material reviewed are listed in Part 3 of Appendix A. This review included a review of attendance sheets for randomly selected lesson plans, and how the licensee handled makeup training for those who missed the normally scheduled training.

At the time of the inspection, the licensee's EOP training program consisted of the initial training prior to EOP implementation (December 1984) consisting of approximately 40-50 hours. Subsequent to that time, the training was given as part of the hot license operator training for Reactor Operators and Senior Reactor Operators. All of the operators having this training have maintained their proficiency with EOPs by completing the following:

- An initial required reading program covering all the EOPs (over a 1-year cycle).
- Approximately 4 hours of lecture on EOP review.

- A portion of the 1-week simulator training at the facility's site-specific simulator during each cycle of requalification training.

- The annual requalification exam.

- The ongoing required reading program, which communicated new information to the operators as revisions were made to the EOPs.

The above training program met the minimum requirements as committed by the licensee and was comparable to training programs for other utilities.

Additionally, the inspectors reviewed the existing training lesson plans and materials listed in Part 3 of Appendix A that were used for both the lecture and simulator training. These lesson plans adequately covered the technical basis behind the procedures, as well as the structure and format of the EOPs. The inspectors did not note any content of the lesson plans and materials that might account for the problems observed concerning the use of the Resource Assessment Trees and control of the plant cooldown rate. These items were discussed among the team members and with the facility staff, and it was agreed that it was a procedural problem; these items are addressed in paragraph 4 of this report.

The review of the training schedules and attendance sheets indicated that approximately an equal amount of training was conducted on each of the procedures. Since the SFRP is more complicated than the Optimum Recovery Procedures (ORPs), it was expected that more training effort should have been conducted on the SFRP. After discussing this with the training staff, the licensee committed to evaluate the adequacy of the training and to revise, as necessary, to emphasize the SFRP. This is an open item (382/8818-05).

c. Operator Interviews

Operators were interviewed to determine their understanding of the EOPs and their responsibilities and required actions, both individually and as a team. Additionally, operators were interviewed to determine whether they felt that actions were duplicated by other operators, whether they were knowledgeable of the requirements for transition from one procedure to another, and whether training was conducted on revised EOPs before they were implemented.

The operators had few comments concerning the attributes discussed above. However, they did express some concerns about using the SFRP. They felt that too much time was wasted confirming what was already verified in the ORPs before implementing the success paths in the SFRP. They also stated that they were more confident using the event-based ORPs.

They also confirmed that they were more confident using the event-based ORPs.

Further comments are addressed in the Human Factors section of this report under the heading "Differences in Operators' Interpretations."

No violations or deviations were identified in the review of this program area.

6. Ongoing Evaluations of EOPs (25592)

The procedures and instructions listed in Part 2 of Appendix A were reviewed to determine if the licensee had an acceptable program for the ongoing evaluation of EOPs in accordance with the guidance of Section 6.2.3 of NUREG-0899. The team also reviewed other records and documents and interviewed licensee personnel to verify that the above requirements had been implemented.

The latest revision of the EOPs (Revision 2) had been issued in January 1987. The technical adequacy of the revised EOPs was determined by a verification and validation program which was performed by individuals, most of whom were in the operations department. A human factors specialist was also utilized, but no personnel from plant engineering were involved. Licensee representatives indicated that Plant Engineering was represented during the PORC review, which involved several hours of briefing by the administrative supervisor. The team verified that the Acting Technical Support Superintendent was in attendance at PORC Meeting 87-08 when the EOP revisions were discussed. This limited review by Plant Engineering did not appear to constitute an adequate technical review of the EOPs. Some of the technical deficiencies identified by the team and documented in other sections of this report may have been identified and corrected by a more indepth review from plant engineering.

The guidance of NUREG-0899 specifies that the licensee's ongoing evaluations should include feedback on technical adequacy and format/style of the EOPs based on operational experience, training, and exercises. The licensee's program for evaluating the technical adequacy of their EOPs was very informal and only marginally adequate. Procedure UNI-1-012 required a review of procedures for technical and administrative adequacy every 24 months. This procedure did not, however, address the requirements for an evaluation based on operational or training experiences.

Instruction OI-019-00 provided a form entitled "Procedure Change Request" and stated that operations personnel requesting a change to a procedure should utilize this form. The licensee's training department issued a handwritten daily instruction, dated July 6, 1988, which required the use of this form by all trainers and trainees. This was issued after the inspector had raised the issue on that date.

The use of the Procedure Change Request Form was the only formalized means of providing feedback regarding the technical adequacy of the EOPs. The daily instruction issued by the Training Department was the only

requirement to use this form; and this requirement (very informal), was applicable only to those who were being trained at the Training Center. As noted above, the licensee's evaluation program was only marginally acceptable for the feedback of training experience. The team found no indications of a program element to assure feedback based on operational experience and exercises. Licensee representatives agreed to review this potential weakness in their program and to revise the program if appropriate. This is an open item (382/8818-06).

The team also noted that the evaluation of staffing and staff qualifications regarding the use of the EOPs was in need of further review. The Training Department had a policy of evaluating the performance of trainees at the simulator. These evaluations were documented and forwarded to the individual's supervisor. The program for evaluating the performance of the operators in the use of the EOPs onshift was marginal. The evaluation was included in the annual performance appraisal of the operators and did not specifically address the operator's ability to deal with emergency or abnormal conditions. This approach also failed to assure input from all of the shift supervisors whom an individual operator might work for during the appraisal period. This area needs to be reviewed and reevaluated for adequacy in meeting the intent of the NUREG-0899 guidance. This is an open item (382/8818-07).

The team also noted that the program for evaluating the adequacy of the EOPs did not address the need for feedback regarding the format, style, or content of the EOPs. The team noted that 50 comments had been compiled to be considered for the next revision of the EOPs. These comments dated back to the issuance of Revision 2 in January 1987. Of the 50 comments only 3 of them addressed format/style changes. Many of the human factor's discrepancies, which were identified by the team and documented in Section 7 and Appendix C of this report, should have been identified by an evaluation program that required licensee personnel to address these types of concerns.

The team reviewed the involvement and oversight provided by QA in the development, implementation, and training on the EOPs. A licensee representative stated, during the course of an interview, that QA had only minimal involvement in EOP development and implementation. He stated that QA had allowed the EOPs to evolve and had only looked at selected EOPs during the performance of emergency drills. The licensee's QA manager committed to review this issue and provide appropriate oversight of EOP development and implementation. This is an open item (382/8818-08).

The team also reviewed the activities of PORC to determine the extent of their oversight over EOP development. Revision 2 to the EOPs was reviewed and discussed during PORC Meeting 87-08. As noted above, the review included an extensive briefing by the Administrative Supervisor. The PORC also did a prior review and evaluation of the verification and validation results for the Revision 2 procedures.

No violations or deviations were identified in the review of this program area.

7. Human Factors Analysis of EOPs (25592)

The human factors review covered a number of areas including the analysis of the procedures, observations of instruments in the control room required for EOPs, observations of instruments outside the control room required for EOPs, and environmental factors. The data were obtained via several methods.

a. Differences in Operator Interpretation of EOP Implementation

Through various methods, the EOP inspection team determined that operators varied widely in their interpretation and execution of EOPs. This was illustrated during a simulator scenario in which operators disagreed on how to interpret and utilize the charts in the SFRP, specifically, the Resource Assessment Trees. Operators' attitudes toward the SFRP also varied, ranging from negative to accepting.

The high variability in operator interpretations, documented in Appendix C, support the inspectors' conclusion that EOP training needs to be improved. If EOP training was better, the differences described in Appendix C may be reduced or eliminated.

b. Manpower Allocation

At W3, the minimum control room shift consists of two Nuclear Plant Operators (NPO), one Control Room Supervisor (CRS), one Shift Supervisor (SS), and one Shift Technical Advisor (STA). In addition, some shifts have an administrative NPO. However, since this position is not required on all shifts, the administrative NPO may be absent from a given shift. As the EOPs are presently written, the minimum shift can perform the EOPs, but a shift's ability to perform the EOPs is reduced when the administrative NPO is not present. (NUREG-0899, Sections 5.8.1, 6.2.3)

The operator roles were not well structured. This conclusion was based on the observation that operators on several occassions omitted the performance of verifying the safety function checklist parameters section of the EOP and that they duplicated each others efforts. On several occasions both reactor operators provided the CRS with the same parameter value when asked. A major factor that contributed to the unstructured nature of operator roles was the task division between the primary and secondary board operators. The control panels consist of two main panels that are perpendicular with one center panel diagonally connecting the two. The primary plant NPO is responsible for the center panel located in the center and adjacent panels on the two main panels. The secondary operator operates the panels located at the two outer ends of the main panels. (One of these panels is the safeguards panel, used during emergencies.) The secondary plant NPO is, therefore, required to move between

opposite ends of the control panels, a distance of approximately 20 feet. Throughout simulator scenarios, the EOP inspectors observed the STA, CRS, SS, and primary plant NPO walk over to the safeguards panel (CP-8) to look at instrument indications. The secondary plant NPO was observed several times asking the primary operator for pressurizer pressure, which was not indicated as such on the safeguards panel (CP-8). The layout of instrument panels and the assignment of operator tasks during EOPs were not wholly compatible. (NUREG-0700, Section 6.1.1.1a and NUREG-0899, Sections 5.8.2 and 5.8.3)

In summary, various factors contributed to the problem of allocation of manpower. As noted above, the reactor operator roles were not well structured, thus encouraging the observed operator task duplications as well as the operator's omissions of EOP actions. Additionally, the absence of an extra operator (administrative NPO) in several simulator scenarios forced the shift supervisor to distribute EOP tasks among two operators instead of three, which exacerbated task allocation.

c. Emergency Operating Procedures Documentation

Several deficiencies were identified in the EOPs including the areas of format, clarity and level of detail. The most significant format issue identified by the EOP inspection team was the licensee's use of a single-column format, which is not recommended in CEN-152, Revision 3. Since W3 operators have been trained on the single-column format, the EOP inspectors understand the utility's hesitation to change the EOPs to the recommended dual-column format. From a human factors viewpoint, however, the utility should recognize that the single-column format requires operators, primarily the CRS, to skim through many contingencies that are not applicable. Placekeeping also is a potential problem because more steps must be checked. Those that do not apply should be somehow checked or crossed out. Also the CRS may become confused by mistakenly considering contingencies that do not apply. (NUREG-0899, Sections 5.5.4, 5.4.6)

Portions of the EOPs were not written clearly. For example, some logic statements were too complex, including more than a single idea. (See Appendix C for specific examples of unclear steps.)

The following items were identified in the Safety Function

- The first pages of the procedure did not adequately explain how to use the procedure.

- The Resource Assessment Tree lacked information or contained misleading information. (NUREG-0899, Sections 5.6.1, 5.6.3, 5.6.4, 5.6.5)

d. Control Room Instrumentation

Some instrument scales were found to be incompatible with some EOP requirements. For example, most EOPs, as well as the safety function status checklists, instructed the operator to read 0.378×10^6/bm/hr Main Feedwater (MFW) Flow. However, the instrument scales used for this parameter are not sufficiently detailed to allow the operator to see this value. The licensee has agreed to round this number to 0.3×10^6 in the forthcoming Revision 3 of the EOPs. Other instances of inappropriate or incompatible instruments are listed in Appendix C. (NUREG-0899, Sections 5.6.8 and 5.6.6)

Labeling of measurement units on instrument scales was found to be deficient in certain instances. On many scales, the units were written in very small characters, causing it to be almost unnoticeable. The containment pressure recorders located on the safeguards panel did not have adequate measurement unit labeling. In fact, two wide range containment pressure recorders exist on the safeguard panel about one foot apart. Paper on one recorder reads "PSIA," the other "PSIG"; these labels are hard to read. When asked what the difference between the recorders was, operators were unable to provide an explanation. It is still unclear why one recorder reads PSIG and the other PSIA. If operators are required to read both, as distinct parameters, then the appropriate distinction between the respective units should be made. (NUREG-0899, Sections 5.6.6, 5.6.7, 5.6.8)

The SG level instruments were not labeled as either wide range or narrow range. Operators had to rely on training to discern which range was on each instrument. To compound the problem, on panel CP-1, only a narrow range level existed. Thus, the operator could not compare it to wide range level on that panel. On the safeguards panel (CP-8), both wide and narrow range levels were displayed but were not labeled as such. Furthermore, both scales contained precisely the same scale, 0-100 percent. This caused the scales to be even less differentiated. The wide range scale on this panel was also not clearly labeled as being a SG parameter. (NUREG-0899, Sections 5.6.6, 5.6.7, 5.6.8).

As stated earlier, a pressurizer pressure indication on the safeguards panel did not exist. An additional control room issue identified during observation of scenarios was the operators' calculations of cooldown rate. The STA spent a considerable amount of time calculating and recalculating cooldown rate, thus detracting from other tasks. The team noted that the plant computer could be set up to perform cooldown rate calculations. (NUREG-0899, Section 5.6.9, NUREG-0700, Section 6.3.2.1c)

e. Local In-Plant Deficiencies

A number of valves in the plant that must be manually operated during EOPs were inaccessible. (These are listed in Appendices C and D). Some of the valves were located between 8 to 20 feet above ground, with no means of reaching them. In one case, operators had to locate a large aluminum ladder and set it against an overhead pipe. This task would be precarious, at best. Some valves were located about 15-20 feet above ground and behind other pipes and components. For these valves, operators must climb up and around the pipes. (NUREG 0700, Sections 6.1.1.3, 6.6.1.1)

The labeling of some components required in the EOPs were deficient. Some of the inaccessible valves was inadequately labeled; the identifications were a metal dog tag type label. These labels cannot be read from a distance. They were small and could easily become dirty, eroded, or broken off. (NUREG 0700, Section 6.6.1.1)

No violations or deviations were identified in the review of this program area.

8. Exit Meeting (30703)

On July 14, 1988, an exit meeting was conducted with the licensee representatives identified in Paragraph 1. The inspectors summarized the inspection scope and findings as described in the Results section of this report.

The licensee acknowledged the inspection findings and noted that appropriate corrective actions would be implemented where warranted. The licensee did not identify as proprietary any of the information provided to, or reviewed by, the inspectors during this inspection.

APPENDIX A

List of Procedures Reviewed

1. Procedures Reviewed on Table-Top

OP-902-000	Emergency Entry Procedure
OP-901-001	Uncomplicated Reactor Trip Recovery Procedure
OP-902-002	Loss of Coolant Accident Recovery Procedure
OP-902-003	Loss of Forced Flow Recovery Procedure
OP-902-004	Excess Steam Demand Recovery Procedure
OP-902-005	Degraded Electrical Distribution Recovery Procedure
OP-902-006	Loss of the Main Feedwater Recovery Procedure
OP-902-007	Steam Generator Tube Rupture Recovery Procedure
OP-902-008	Safety Function Recovery Procedure

Note: The inspection team also reviewed the Technical Guidelines for each procedure listed above.

2. PGP Administrative and Validation and Verification Procedures

UNT-01-012	Emergency Operating Procedure Development, Review and Approval, Revision, and Deletion

3. EOP Training Material and Lesson Plans Reviewed

OI-019-00 Operating Instructions: Development of Operation Procedure Administration Group.

L581-507-30	Mitigating Core Damage Chapter 7-Gas
L584-200-00	Introduction to Function Based EOPs
L584-203-30	Function Based EOPs
L584-302-10	FBEOPs/Loss of Coolant Accident/Excess Steam Demand Recovery Procedure
L584-303-10	FBEOPs/Loss of Main Feedwater Recovery Procedure
L584-304-10	FBEOPs/Uncomplicated Reactor Trip Recovery Procedure
L584-401-00	FBEOPs/Loss of RC Flow/Loss of Offsite Power/Natural Circulation Demonstration Recovery Procedure
L584-402-10	FBEOPs/Degraded Electrical Distribution Recovery Procedure
L584-403-10	FBEOPs/Safety Function Recovery Procedure
L585-203-10	FBEOPs/Review and Revision
L586-501-10	FBEOPs/Review and Revision 2
L587-207-00	FBEOPs/Review

4. Operations Procedures Reviewed Which Were Referenced In EOPs

OP-1-002 Reactor Coolant Pump Operations
OP-3-003 Condensate-Feedwater Operations
OP-3-010 Blowdown Operating Procedure
OP-5-001 Auxiliary Boiler
OP-8-006 Hydrogen Recombiner
OP-8-010 Containment Hydrogen Analyzer
OP-10-001 General Plant Operations

APPENDIX B

Technical Review Questions and Answers

The following are inspection team questions as a result of reviews of the W3 EOPs. In the following responses, the licensee either provided clarification for the deviations from CEN-152, or acknowledged that deficiencies identified by the inspection team and agreed to correct them in the next revision to the EOPs. Section 5 of the report provides further discussion regarding some of these items.

1. OP-902-000, Emergency Entry Procedure

   Q1: C.1.B., colons should be periods (generic to immediate actions).

   R1: The next revision will follow the Writer's Guide and eliminate colons for steps with no substeps or with no list associated with the action.

   Q2: Containment Spray Pump flow should be checked in immediate actions (Step 14).

   R2: This comment will be incorporated in Revision 3.

   Q3: Concerning Steps 2b, 3c, and 4b of Attachment 1, which subcooling indication instruments from QSPDS are used to determine subcooling?

   R3: All available subcooling information should be looked at for comparison. The training process will emphasize when the use of RVLMS subcooled margin indication would be appropriate.

   Q4: Why does the hierarchy in the entry procedure differ from EPGs?

   R4: In the next revision to the EOPs, the Immediate Actions will be listed in the order of the related safety functions of CEN-152.

2. OP-902-001, Uncomplicated Reactor Trip Recovery Procedure

   Q1: Page four, Paragraph E.1 caution - No timeframe designated for completing one set of the SF Status Checklist. "Continuously" is too vague a word. Once per 10-15 minutes should be a goal and the completion time logged.

   R1: Operator training is used to determine the actions required for continuously monitoring safety functions. Logging on a time interval is cumbersome for the operators.

3. <u>OP-902-002, Loss of Coolant Accident Recovery Procedure</u>

Q1: Why is Core Exit Temperatures (CET) or Reactor Vessel Level Monitoring System (RVLMS) thermocouple TC not used for Note 5? CET is considered for next note.

R1: CET temperature will be specified in Note 5 in the next revision.

Q2: Step 8 - Since the purpose of Step 8 is to isolate the leak, why initiate SIAS? Technical Guide does not explain this.

R2: SIAS provides isolation functions.

Q3: Step 8 purpose is not clear.

R3: Step 8 will be reworded to include the purpose of the step.

Q4: Step 21c should identify whether CETs or RWLMS indications should be used.

R4: CETs will be specified in the next revision.

Q5: Step 17 is two sentences with one idea. Should have one sentence using "refer to."

R5: Will combine sentences in next revision.

Q6: Step 21c and 52d should refer to CET.

Q7: Step 57 - refer to CEN-152, Step 40A, Why was information in 40A omitted?

R7: Will be addressed in Revision 3 of EOPs.

Q3: Step 91 - H2 concentration of 3 percent is less conservative then CEN-152 which uses 2 percent. Why wait 24 hours to turn on Hydrogen recombiner? What is the basis for the difference in Hydrogen concentration and the 24 hour time?

R8: Reference FSAR, Section 6.2.5.3, for discussion of the system and the 3 percent criteria. Two percent is a bracketed number in CEN-152, i.e., generic, whereas 3 percent is the Waterford 3 plant specific number. Hydrogen recombiners will be started at Hydrogen concentration of 3 percent <u>or</u> 24-hours, whichever comes first. Twenty-four hours is more conservative that CEN-152 or 3 percent criteria.

4. <u>OP-902-003, Loss of Forced Flow Recovery Procedure</u>

Q1: Step 9 of OP-902-003 should be moved to an appropriate place.

R1: Will be moved in next revision of EOPs.

5. OP-902-004, Excess Steam Demand Recovery Procedure

Q1: Sampling activity S/Gs for activity is not early enough in the procedure because it will take Chemistry a while to do this. OP-902-004 calls for this at Step 35, Page 15, while CEN-152 calls for it in Paragraph 3.

R1: Substep 35c will be moved between Step 12 and 13 in next revision.

6. OP-902-005, Degraded Electrical Distribution Recovery Procedure

Q1: Step 17 of OP-902-005 does not open PW 9017 A&B to supply potable water.

R1: Will be incorporated in next revision of EOPs.

7. OP-902-006, Loss of Main Feedwater Recovery Procedure

Q1: Step 4 should be moved to Step 8 to provide time to verify loss of MFW and trip RCP 1A and 2A before kick out to SFRP.

R1: Will be incorporated in next revision of EOPs.

8. OP-902-007, Steam Generator Tube Rupture Recovery Procedure

Q1: Need Plant specific curves for two RCP operation. The procedure should address NPSH. (comment is for all EOPs that refer to RCP operation)

R1: Plant Engineering to provide.

Q2: Step 36 should reflect that combinations may be used to cool SG U tubes for U tube voiding.

R2: Will incorporate in next revision of EOPs.

APPENDIX C

Specific Examples of Human Factors Discrepancies

1. Differences in Operator's Interpretation of EOP Implementation

Operators differed in their understanding and/or execution of the EOPs in following ways:

- The importance of EOP attachments relative to the body of the EOP.
- What to do if items in the attachment lists are not verified.
- Placekeeping methods: some operators used the checkoff spaces, others did not.
- Order of executing EOP steps: For example, if a step required a certain parameter value that had not yet been attained, some operators skipped the steps and came back to it later; others waited for the parameter before continuing with the EOP.
- Interpretation of "refer to," "commence," and other references. Some operators performed the referenced procedure in parallel with the current EOP; others temporarily exited the current EOP to perform the referenced procedure.
- Interpretation of orange dots on control room instrument labels.

2. EOP Documentation

a. EOP 002, LOCA, Caution 13.d. "DO NOT rely solely on RVLMS when RCPs are operating, use more than one instrument to verify core is covered." Statement should be reversed, rewritten, or punctuated differently to highlight the recommendation in the second half.

b. All EOPs. Colons used to introduce the name of an attachment or procedure should be changed to commas or deleted as appropriate. Commas should also follow the named attachment or procedure.

c. EOP 002, LOCA, Step 21. "IF NO RCPs are operating AND Reactor Coolant System Subcooling Margin ≥28°F, THEN Check Two Phase Natural Circulation AND Break Heat Removal by the following": This step identifies two antecedent conditions that must be satisfied and two consequent actions that must be taken. It is a complex logic statement that presents more than a simple idea.

d. EOP 004, ESDE, Step 47. This step includes a series of substeps that continue onto the subsequent page, beginning with an OR. At the bottom of the first page, it is neither clear that the step continues

nor that the preceding substeps are to be used disjunctively (with forthcoming substeps).

e. EOP 008, SFR, Page 5 of 176, Step 5. This is an action step embedded within cautions, notes, and references to foldouts. It is not clear why this step was placed in this location in the procedure. It could easily be missed by operators.

f. EOP 002, LOCA, Step 30.b. Operators are required to maintain Emergency Feedwater (EFW) level between 68 percent and 71 percent wide range. This difference can only be seen clearly on the QSPDS, which is not referenced in the EOP step.

g. EOP 002, LOCA, Step 14. "If ALL Safety Injection (SI) termination criteria (Step 13) are satisfied, THEN throttle OR stop SI FLOW one train at a time AND stop charging pumps as necessary to control pressurizer level 33 percent to 60 percent." This step is complex, consisting of more than one required action. It also lacks sufficient detail because it does not state how flow should be stopped: should the pumps be stopped, the valves closed on both or just one train? Further, "throttle" should probably be "reduce" in this step.

h. EOP 002, LOCA, Step 15. This step states to "reinitiate SI flow." "Reinitiate" in this step means to start the pumps and open the valves; these should be specified in the step.

i. EOP 004, ESDE, Step 47.b, EOP 002, LOCA, Step 58.b. "Stop any depressurization." More detail should provide the necessary guidance on exactly how the depressurization should be stopped.

j. EOP 004, ESDE, Note 5. ". . .PRESSURIZER TEMPERATURE WATER" should be changed to read "Pressurizer Water Temperature."

k. EOP 001, Steps 8.a.2, 8.b.1. "Emergency Borated 190 ppm," and "Emergency borated 321 ppm." Both steps should include "an additional" between borated and the numerical values to ensure operators do not erroneously borate only up to 190 ppm and 321 ppm.

l. EOP 001, Step 21.i. "Calculate and adjust Volume Control Tank blend rate." Additional detail should be provided regarding the blend rate.

m. EOP 003, Attachment 1. The Note at the top of the page begins with "These valves. . ." implying that the Note is applicable to all listed valves, when it actually only applies to the last two.

3. Control Room Deficiencies

a. EOP 002, LOCA, Steps 40, 43, 44, and other EOPs. Operators are required to distinguish between containment pressures reading 17.1 psia vs. 17.7 psia. This difference cannot be accurately

perceived on the two scales (CP-7). The scales display identical orange setpoint bands, both marking 17.1 although the setpoints for the two parameters are different: 17.1 vs. 17.7.

b. EOP 004, SF Status Checklist, 6.b, and other EOPs. The checklist instructs operators to verify that containment spray flow is ≥1950 gpm. The illustrated setpoint on the Containment Flow instrument, however, is incorrectly set at 1850 gpm. This indication appears on CP-8 (safeguards panel).

c. EOP 002, LOCA, Step 41.d. The step directs operators to place switches to the "NORMAL" position. The actual switch, however, does not have a NORMAL position.

d. OP-3-003, Condensate Feedwater, Page 45, Caution. This procedure references a valve in the control room, AFW-125, Pressure Relief Valve. However, the valve controller indicator is not labeled in the control room (or simulator).

e. EOP 002, LOCA, Step 10.a and other EOPs. The operator checks the Steam Bypass Controller, which consists of two adjacent scales. The left scale is the parameter value, and the right one is the setpoint value. The scales are not respectively labelled, so the operator must remember or deduce which scale is which.

f. Recorders on the safeguard panel and other panels were difficult to read because:

- Increments were not easily readable.
- Many were dual-parameter recorders.
- Arrows were too far from the pointed-to value.
- Pen lines were thin.
- Pen lines could overlap, making them indiscernible.
- Arrows could overlap, completely obscuring one another.
- Measurement units were not clearly labeled.

4. <u>Local In-Plant Deficiencies</u>

a. EOP 002, LOCA, Step 33 b.1. The procedure directs operators to locally open the Auxiliary Boiler (AB) Steam Supply to MFW Pump A Isolation valve. This valve is located approximately 15 feet above the scaffolding. No ladder is readily available.

b. EOP 002, LOCA, Step 33 c.1. The procedure required operators to locally open the AB Steam Supply to MFW Pump B Isolation valve. This

valve is approximately 8 feet above the scaffolding. Its label is completely obscured.

c. EOP 005, Steps 24.a, b, and c. The operator is instructed to locally open one of three Main Condenser Vacuum Breaker valves. All three valves are totally inaccessible, located about 15 feet high and behind the feedwater heaters. Operators must climb onto and around pipes to reach the valves.

d. EOP 005, Step 23.b. Operators are directed to locally verify that the Seal Oil System is operating. During a walkdown, however, no local indications were found.

e. EOP 003, Step 27.a. Operators must locally open the Gland Steam Auxiliary Steam Supply valve, which is inaccessible and requires the operators to climb a ladder.

f. EOP 003, Step 27.c. "Verify Gland Steam Header Pressure ≥90 psig." The value is not labeled as such. It only had a label with the component number. The valve indication reads in "PSI" rather than "PSIG."

g. EOP 003, Step 27.f. Operators must verify that the MFW Pump Turbine Gland Seal Steam Pressure Controller "maintains 4 psig." The controller is not clearly labeled. The unit is labeled "psi." It is not possible to visually perceive exactly 4 on the scale.

APPENDIX D

Verification/Validation Review Comments

Specific comments on the control room walkdowns and the review of the validation programs are provided below. The licensee committed to correct these weaknesses or review specific steps for potential changes. Section 4 of this report provided further discussions regarding verification and validation.

1. General

   a. Labeling

      (1) Motor control center A 3115 and B 3115 are referred to in Step 78 of OP-902-007 as 311AS and 311BS.

      (2) The tag for the blowdown demin air operated outlet dump valve to regen waste tank (BD512) is missing from the local panel.

      (3) Valve controller 1 indicator for AFW-125 is not labeled in the control room and the simulator.

      (4) Valve BD3401 does not have an identification tag.

      (5) Valve numbers are missing for Valves AFW 125 and BD 103B in the simulator.

      (6) Valve IB (51226B) is labeled 51266B in the simulator.

   b. Valves Hard to Reach

      The following valves referred to in the EOPs that are high off the floor with no permanent ladder or platform available for an operator to stand on while operating the valves. The licensee has agreed to review these locations and determine if ladders are stored close enough to the valve location or whether ladders should be moved into the area.

      (1) OP-902-007, Step 46.b. Main Steam to Gland Steam Isolation MS 148.

      (2) OP-902-002, Step 47.b.1. AB Steam supply to MFW Pump A Isolation ABS 3144A.

      (3) OP-902-002, Step 33.b.2. Main Steam to MFW Pump A Stop Valve MS215A.

      (4) OP-902-008, Step E3.5.a and b (page 42) A and Charging Header to Hot Leg Injection Headers. B Isolation Valves SI 504 and SI 505.

2. OP-902-002, LOCA

   a. Steps 69a and 83a. The condensate storage pool make up valve No. CMU141 is missing from the procedure.

3. OP-902-007, SGTR

   a. Step 43A refers the operator to OP 3-010 Blowdown Operation. Step 6.10.12.2 of OP-3-010 has to operator position the blowdown denim acid and caustic pump control switches to "OFF." This system is not in use and consideration should be given to removing the controls from the panel and the step from the procedure.

   b. Step 45 has the operator start the AB and refers to Procedure OP-5-001. Presently, the licensee is installing a new temporary AB which will be used while the permanent AB is being retubed. The licensee is reviewing OP-5-001 and may issue a temporary procedure for the new boiler.

   c. Step 46c instructs the operator to check gland steam pressure between 1-5 to 3 psig. This pressure appears lower than is presently being used.

APPENDIX E

List of Abbreviations

AB	Auxiliary Boiler
AFW	Auxiliary Feedwater (not emergency)
CEN-152	Combustion Engineering Emergency Procedure Guidelines
CET	Core Exit Thermocouple
CP	Control Panel
CRS	Control Room Supervisor
EFW	Emergency Feedwater
EOP	Emergency Operating Procedure
EPG	Emergency Procedure Guidelines
ESDE	Excess Steam Demand Event
LOCA	Loss of Coolant Accident
MFW	Main Feedwater
NPO	Nuclear Plant Operator
NPSH	Net Positive Suction Head
ORP	Optimum Recovery Procedure (Event Based)
PORC	Plant Operations Review Committee
QSPDS	Qualified Safety Parameter Display System
RCP	Reactor Coolant Pump
RVLMS	Reactor Vessel Level Monitoring System
SFRP	Safety Function Recovery Procedure
SF	Safety Function
SG	Steam Generator
SI	Safety Injection
SIAS	Safety Injection Actuation System
SS	Shift Supervisor
STA	Shift Technical Advisor
W3	Waterford 3