NUREG-0843
Supplement No. 1

Safety Evaluation Report

related to the operation of St. Lucie Plant, Unit No. 2

Docket No. 50-389

Florida Power and Light Company
Orlando Utilities Commission of the City of Orlando, Florida

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

December 1981

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1 INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

On October 9, 1981, the Nuclear Regulatory Commission (NRC) staff issued a safety evaluation report (SER) related to the operation of St. Lucie Plant Unit 2. In that SER, the staff indicated certain issues where either further information or additional staff effort was necessary to complete the review.

The purpose of this supplement is to update the SER by providing (1) our evaluation of additional information submitted by the applicant since the SER was issued, (2) our evaluation of the matters the staff had under review when the SER was issued, and (3) our response to comments made by the Advisory Committee on Reactor Safeguards in its report dated November 17, 1981 (Appendix B).

Each of the following sections of this supplement is numbered the same as the section of the SER that is being updated, and the discussions are supplementary to and not in lieu of the discussion in the SER. Appendix A to this supplement is a correction and continuation of the chronology. Appendix B is the Advisory Committee on Reactor Safeguards report dated November 17, 1981. Appendix C is the Human Factors Engineering Branch (HFEB) safety evaluation report on the St. Lucie 2 control room design review.

1.7 Summary of Outstanding Issues

Section 1.7 of the SER contained a list of outstanding issues. This supplement addresses the resolution of a number of these issues previously identified as open. These are listed below, along with the section of this report wherein their resolution is discussed.

(1) Stability of Slopes (2.5.5)
(2) Turbine Missiles (3.5.1.3, 3.5.3)
(3) Seismic Displacement of Category I Pipes (3.7.2, 3.7.3)
(4) Matrix Power Supply Test Results (7.1.3, 7.2.5) becomes confirmatory
(5) Fire Protection (7.4, 7.5, 8.3.3, 9.5.1) becomes confirmatory
(6) Starting Voltage for 460 V-ESF Motor (8.3.1.1)
(7) Station Electric Distribution System Voltages (8.4.6)
(8) Operator Training (13.2.1)
(9) Operating and Maintenance Procedures (13.5.2)
(10) Station Blackout (ALAB 603) (15.10.8, previously Appendix C, A-44) becomes confirmatory.
(11) Emergency Operating Procedures (I.C.7) becomes confirmatory
(12) Control Room Design (I.D.1) becomes confirmatory
(13) Inadequate Core Cooling Instrumentation (II.F.2) becomes a license condition
(14) Degraded Core Training (II.B.4)

At this time, there remain a number of safety issues that have not yet been resolved. These will be addressed in a subsequent supplement to the SER. The following is a list of these items.

(1) Pump and Valve Operability Assurance (3.9.3.2)
(2) Seismic Qualification (3.10)
(3) Environmental Qualifications (3.11)
(4) Seismic and LOCA Loads (4.2.3.3)
(5) Fuel Handling System Light Loads (9.1.4)
(6) Emergency Planning (13.3)
(7) ATWS Procedures (15.10.6)
(8) TMI Issues (Emergency Operating Procedures (I.C.1, I.C.8))

1.8 Confirmatory Issues

At the time of the SER issuance there were several issues which were essentially resolved to the staff's satisfaction, but for which certain confirmatory information had not yet been provided by the applicant. Since that time, the staff has reviewed this information and, as expected, has confirmed the preliminary conclusions. These issues are listed below with appropriate references to subsections of this report.

(1) Non-LOCA core coolability (4.2.1.3, 4.2.3.3)
(2) CEA fretting wear (4.2.1.1, 4.2.3.1)
(3) Fragmentation of cladding (4.2.1.3)
(4) Supplemental ECCS calculations (4.2.3.2(f), 4.2.3.3(c))
(5) Adequate core cooling following moderate energy pipe break when in shutdown cooling (5.4.3)
(6) Waterhammer test (10.4.7)

At this time several issues remain for which the staff has not yet received the necessary confirmatory information. These issues, which are listed below, will be addressed in a subsequent supplement to the SER.

(1) Surface faulting (marine seismic reflection survey) (2.5.3)
(2) Other Category I structures (Masonry Walls) (3.8.4)
(3) Dynamic analysis of reactor internals (3.9.2.2)
(4) Preoperational flow-induced vibration testing of reactor internals (3.9.2.3)
(5) Piping load combinations and stress limits (3.9.3.1)
(6) Inservice testing of pumps and valves (3.9.6)
(7) Intersystem LOCA (3.9.6)
(8) Design stress and strain on fuel system (4.2.3.1)
(9) CEA axial growth (4.2.3.1(g))
(10) Rod pressure (4.2.3.1)
(11) Fuel rod mechanical fracturing (4.2.3.2(g), 4.2.1.2(g))
(12) Analog core protection calculator (4.4.5)
(13) Boron mixing test results (5.4.3)
(14) Natural circulation cooldown tests (5.4.3)
(15) Upper head voiding (5.4.3)
(16) Loose parts monitoring (4.4.4)
(17) Service history of HPSI pumps (6.3.2)
(18) Sump vortex test (6.3.3)

(19) Logic matrix and logic matrix power supplies (7.2.5)
(20) Shutdown Cooling System (7.4.4)
(21) Fire Protection (9.5.1)
(22) Reactor Coolant Pump Shaft Seizure and Shaft Break (15.5)
(23) Feedwater system pipe breaks (15.10.2)
(24) Inadvertent boron dilution event (15.6.3)
(25) Inadvertent opening of PORV (15.10.5)
(26) Steam generator tube failure (with and without AC) (15.10.4)
(27) Emergency Operating Procedures (I.C.7)
(28) Control Room Design Review (I.D.1)

1.9 License Conditions

Section 1.9 of the SER contained a list of license conditions. This supplement addresses the resolution of one of these conditions. This is listed below, along with the section of this report wherein the resolution is discussed.

(1) Barrier design procedures (3.5.3)

At this time the number of license conditions that remain are listed below:

(1) Population Distribution (2.1.3)
(2) Fragmentation of embrittled cladding (4.2.3.3(a))
(3) Postaccident monitoring instrumentation (7.5.4)
(4) Non-safety loads on emergency power sources (8.4.2)
(5) Containment electrical penetrations (8.4.3)
(6) Emergency diesel engine auxiliary support systems (9.5.4.1)
(7) Turbine disc integrity (10.2.1)
(8) Secondary water chemistry (10.3.4)
(9) Liquid waste management (prevent tank overflow) (11.2)
(10) Postaccident sampling capability (Section 22, II.B.3)
(11) Inadequate Core Cooling Instrumentation (Section 22, II.F.2)

1.11 Special Plant Features

Several corrections were needed in this section; therefore, the entire section has been rewritten and presented below.

(1) Automatic Auxiliary Feedwater System

The function of the Auxiliary Feedwater System (AFWS) is to ensure a sufficient supply of cooling water to the steam generators when main feedwater is not available. The AFWS is provided with complete sensor and control instrumentation to enable the system to automatically respond to a loss of steam generator inventory.

(2) Containment and Shield Building Design

St. Lucie 2 possesses an advanced containment design which, in conjunction with a holdup, dilution, and multiple pass filtration system, significantly reduces offsite doses in the event of postulated accidents.

The design embodies a free-standing steel containment vessel within a separate reinforced concrete shield building. There is an annulus between these two structures in which are supply and return ring ducts. To these ducts are connected two independent and safety-grade trains of air handling and filtration equipment. This system of air handling and filtration equipment is known as the shield building ventilation system (SBVS).

The annulus is maintained at atmospheric pressure during normal operation and is maintained at a negative pressure over the course of an accident. As a result, any leakage in the shield building structure causes atmospheric air to be drawn into the annulus rather than leakage of contaminated annulus air to the atmosphere.

Following an accident, the annulus pressure is rapidly drawn down by the SBVS and maintained at a negative pressure relative to atmospheric pressure. Exhausted air is filtered prior to release to the atmosphere. Vacuum control for the annulus and cooling air for the filters is provided by the use of makeup cooling air lines located outside the annulus upstream of the filter train.

2 SITE CHARACTERISTICS

2.1 Geography and Demography

2.1.3 Population Distribution

The staff's response to an ACRS recommendation as stated in its report to the Chairman dated November 17, 1981, regarding a periodic review of population growth around the plant site so that timely plans for appropriate preventive or remedial measures, if required, could be made is discussed below.

We will require that the applicant periodically obtain and submit to NRC the actual and projected population around the St. Lucie site in order to determine what additional measures, if any, should be undertaken to assure the public health and safety.

To achieve these purposes, the applicant shall, commencing in 1986 and about every 10 years thereafter, prepare and submit an estimate of the actual population within 10 miles of the plant, including the distribution by distance and direction, and listing permanent residents, seasonal residents and transients. The basis for the population estimates shall also be provided. In addition, when data from the 1990 Census becomes available, and about every 10 years thereafter, the applicant shall prepare and submit revised population data based on the decennial census out to 50 miles. Seasonal residents and transients within 10 miles shall also be listed. Along with the decennial census, the revised population projections for 10-year intervals out to projected end-of-plant life shall also be provided. In summary, the actions indicated above mean that about every 5 years the applicant will prepare and submit an estimate of the actual population within 10 miles of the plant and about every 10 years within 50 miles of the plant. The higher frequency is focused on the population within the 10 mile EPZ of the plant, since it is anticipated that the significant population growth will occur in this area.

The NRC staff and the applicant will, upon consideration of the population data, plant design features, and operational characteristics of the St. Lucie plants in relation to other nuclear power plants, make a determination of what additional measures, if any, are deemed necessary to assure the public health and safety. For example, based on the revised population data, the applicant will determine what changes, if any, should be incorporated into the Emergency Plan.

2.5 Geology and Seismology

2.5.5 Stability of Slopes

2.5.5.1 Soil Stabilization

In the SER (NUREG-0843) dated October 1981, we stated that stabilization of the slopes north and south of the intake structures for Units 1 and 2 by use of compaction piles has not produced the expected densification of loose, potentially liquefiable, in situ soils in these areas. Part of that conclusion was based on an examination of the applicant's pile-driving report dated January 1976 which indicated that extensive pre-drilling was used to facilitate installation of piles. It was also based on the report that almost all of the piles dropped about 40 to 60 ft from the ground surface into the pre-drilled holes under only the weight of the pile and hammer. Such pre-drilling would have reduced the potentially beneficial effects of the compaction piles that were expected to densify the in situ soils by displacement and vibration.

Subsequent to the issuance of the SER (NUREG-0843 dated October 9, 1981), the applicant provided additional information in their submittal dated October 27, 1981 which shows that the compaction piles helped stabilize the two slopes in question. (Reference: Letter from Florida Power and Light Company to NRC, dated October 27, 1981, with attachments relating to the topic of Compaction Piles.) While the referenced letter acknowledged that piles did drop through the pre-drilled holes in the compacted Class II backfill overlying the in situ soils, the new information contained in the attachment to that letter indicates that the piles were driven into the loose in situ soils thus densifying them by displacement and vibration.

The applicant has provided additional information and corrected or modified certain statements made in their consultant's report dated January 1976. The applicant's October 27, 1981 submittal indicates: (1) the in situ soils were pre-drilled with only one auger pass to facilitate pore pressure relief; two to four additional passes were made only to the bottom of the Class II fill to relieve skin friction between the backfill and the pile, and (2) generally, no material was brought to the surface from the in situ soils portion of the hole as a result of pre-drilling operations. However, in one case, material equal to about 50 percent of the volume of the pile was removed from the upper half of the hole in the Class II fill. The applicant's visual estimate of material removal from other pile locations was essentially zero. Generally, 1/2 to 1 cu yd of sand was used in backfilling adjacent to these piles.

The applicant's basis for the above statements is a field trip report dated October 22, 1975 by the applicant's consultant (Reference: Memo from Mercurio to Ehasz of Ebasco Services dated October 22, 1975). The staff has accepted the applicant's revised statement that the in situ soils were not pre-drilled more than once.

With respect to the dropping of the piles into the pre-drilled holes, the applicant provided cross sections for all of the 72 piles used for compacting the slopes in question. This information indicates that, except for 12 piles, the piles did not fall freely into the in situ soils but were driven as required. For those 12 piles, the data indicate that the piles dropped up to 10 ft below the interface between the Class II fill and the in situ soil before driving began. The applicant believes that the reason for this is the low strength of occasional discontinuous plastic clay seams that exist between El-20 ft and El-45 ft. This is exemplified in borings B-103, B-104, and B-117 drilled near the two intake structures. The staff has verified the existence of these soft clay seams from the boring logs included in the FSAR Vol. 3, Appendix 2.5A, and is, therefore, generally satisfied with the applicant's explanation regarding the free fall of the piles in these 12 cases.

The applicant has provided in its submittal dated October 27, 1981, a list of other projects in which compaction piles were used for achieving soil densification.

On the basis of an overall evaluation of the additional data provided by the applicant on October 27, 1981, the staff is satisfied that 60 of the 72 compaction piles have been driven, as required, into the loose in situ soils in the slopes adjacent to the intake structures. The staff believes that even if the in situ soil around the 12 piles that may not have been adequately densified should undergo liquefaction locally, the volume of soil that could move into the intake pool area will be so small that the remaining channel would still provide an adequate supply of emergency cooling water for a safe shutdown of the plant.

2.5.5.2 Conclusion

Based on a review of the updated compaction pile installation procedures provided by the applicant on October 27, 1981, the staff is satisifed that the loose in situ soils in the slopes north and south of the intake structures have been adequately densified to assure effective stability of these slopes in the event of the postulated safe shutdown earthquake with a peak acceleration level of 0.1g.

3 DESIGN CRITERIA - STRUCTURE, COMPONENTS, EQUIPMENT AND SYSTEMS

3.5 Missile Protection

3.5.1 Missile Selection and Description

3.5.1.3 Turbine Missiles

According to General Design Criterion 4 of Appendix A to 10 CFR Part 50, nuclear power plant structure, systems, and components important to safety shall be appropriately protected against dynamic effects, including the effects of turbine missiles. Systems important to safety are defined to be those structures, systems, and components necessary to ensure:

1. The integrity of the reactor coolant pressure boundary,

2. The capability to shut down the reactor and maintain it in a cold shutdown condition, or

3. The capability to prevent accidents that could result in potential offsite exposures that are a significant fraction of the guideline exposures of 10 CFR Part 100, "Reactor Site Criteria."

The St. Lucie Unit 2 turbine-generator placement and orientation is unfavorable with respect to the station reactor buildings. This configuration places the corresponding reactor auxiliary building, control room, battery room, condenser storage tank, steam trestles, and intake cooling water structure, as well as the containment building within the low trajectory missile (LTM) strike zone (see Regulatory Guide 1.115).

Applicant's Analysis and Conclusion

The applicant has performed an analysis to evaluate the probability of damage from postulated turbine missiles to the Unit 2 structures, systems, and components important to safety.

The applicant stated that using the Westinghouse "Turbine Missiles Report" published in 1981, but not received by the staff, the missile generation probabilities (P_1), both for design and destructive overspeed failures, are calculated to be about 10^{-11} per year. However, using the NRC recommended (Regulatory Guide 1.115) values of P_1 of approximately 10^{-4} and the NDRC perforation formula in the Regulatory Guide, the applicant has calculated the total damage probability due to low trajectory missiles (LTM) to be 2.5×10^{-7}, and the one for high trajectory missiles (HTM) to be 1.3×10^{-7} per year.

The applicant calculated that the design and destructive overspeed strike probabilities are 1.9×10^{-3} and 3.7×10^{-3} per turbine failure, respectively. Based on the historical missile-producing turbine failure rate, 6×10^{-5} per year for design overspeed failure and 4×10^{-5} per year for destructive overspeed failure, their analysis yields a total probability of unacceptable damage to systems important to safety due to LTMs of 2.6×10^{-7} per year.

With regard to high trajectory missiles (HTMs), the applicant has performed an analysis and calculated that for systems important to safety in Units 1 and 2, the total HTM strike probabilities for postulated missiles from Unit 2 turbine design and destructive overspeed failures are 1.3×10^{-3} and 1.4×10^{-3} per turbine failure, respectively. This yields a total HTM risk rate of 1.3×10^{-7} per year.

The applicant concludes that in view of large differences (i.e., 5 to 6 orders of magnitude) in missile generation probability, P_1 between the turbine manufacturer calculation and the NRC suggested value, and various conservative assumptions made in calculating overall damage probabilities, no specific protective barriers or reorientation of equipment is deemed necessary.

Staff Evaluation

We have verified applicant's LTM risk assessment by an independent analysis which considered the geometric relationship of the turbine to systems important to safety and which, assuming straight line trajectories, estimated the solid angle subtended by these systems to arrive at a probability of an LTM striking and damaging the systems. Our analysis concentrated on the reactor coolant pressure boundary and the interior of the battery and control rooms. Unit 1 systems important to safety are not in the direct path of postulated LTMs from Unit 2; hence, they were not considered. Since the steam trestles lie in the shadow of the turbine pedestal and there is an intertie between the St. Lucie Unit 1 and Unit 2 condensate storage tanks, such that in the event of damage to the St. Lucie Unit 2 tank, the Unit 1 tank can provide sufficient auxiliary feedwater for safe shutdown of both units, neither system was included in our analysis. The intake structure was not included either, based upon the applicant's analyses that show that it makes a negligible contribution to the risk.

We assumed that postulated missiles leaving the turbine casing have uniform velocity distributions from zero to the maximum values stated in the FSAR. The containment building walls were approximated as plane surfaces parallel to the turbine axis with the outer wall being reinforced concrete 3 ft thick and the inner wall being steel 1.9 in. thick. The west walls of the battery and control rooms are reinforced concrete 2 ft thick. Though the walls of the turbine building and intake structure are considered negligible barriers, credit was taken for the effect of the moisture separations and high pressure heaters on the turbine floor. We used the NDRC missile barrier perforation formulae.

By our analysis, reasonable estimates of design and destructive overspeed strike probabilities are 4×10^{-3} and 9×10^{-3} per turbine failure, respectively. Assuming design and destructive overspeed turbine failure rates 6×10^{-5} and 4×10^{-5} per year, respectively, we obtained a total probability of unacceptable damage to systems important to safety due to LTMs of 6×10^{-7} per year. The sum of this value and the one for HTMs of 1.3×10^{-7} per year are within the 10^{-6} to 10^{-7} range and is acceptable to the staff.

We have also reviewed other factors that have a bearing on the probability of missiles generation. With regard to destructive overspeed, the applicant stated that the failure probability is less than 1×10^{-11} per year.

Overspeed protection is accomplished by three independent systems; i.e., normal speed governor, mechanical overspeed, and electrical backup overspeed control systems. The normal speed governor modulates the turbine control valves to maintain desired speed load characteristics and it will close the intercept valves and control valves at 103 percent of rated speed. The mechanical overspeed sensor trips the turbine stop, control, and combined intermediate valves by deenergizing the hydraulic fluid systems when 111% of rated speed is reached. The turbine steam stop valves, control valves, reheat stop valves, and intercept valves are designed to fail close on loss of hydraulic system pressure. The electrical backup overspeed sensor will trip these same valves when 111.5% of rated speed is reached by independently deenergizing the hydraulic fluid system. Both of these actions independently trip the energizing trip fluid system. The overspeed trips systems can be tested while the unit is on-line.

An inservice inspection program for the main steam stop and control valves and reheat valves will be provided and include: (a) dismantling and inspection of all turbine steam valves, at approximately 3-1/3 year intervals during refueling or maintenance shutdowns coinciding with the inservice inspection schedule, (b) exercising and observing at least once a week the main steam stop and control, reheat stop, and intercept valves.

We conclude that the turbine generator overspeed protection system for St. Lucie 2 plant will assure that the probability of missile generation in case of a postulated destructive overspeed failure is well below the historical value of 4×10^{-5} per year.

Similarly, for the design overspeed failure case, the NRC staff has reviewed Section 10.2.3, "Turbine Disc Integrity."

The turbine was manufactured by Westinghouse. The turbine discs and rotors are forged from vacuum degassed steel by processes that minimize flaws and provide adequate fracture toughness. These materials have the lowest fracture appearance transition temperatures and highest Charpy V-notch energies obtainable on a consistent basis. The preservice inspection program calls for 100% ultrasonic test (UT) of each rotor and disc forging before finish machining and magnetic particle test (MT) after finish machining. No MT flaw indications are permissible in bores, holes, keyways, and other highly stressed regions.

Since 1979 the staff has known of the stress corrosion cracking problems in low pressure rotor discs in Westinghouse turbines. Appropriately conservative inspection intervals have been effective in monitoring crack growth to permit repair or replacement of discs well in advance of failure. The applicant has submitted to the staff the materials properties of the low-pressure turbine discs as well as the calculations of critical crack sizes. The method used to predict crack growth rates is based on evaluating all of the cracks found to date in Westinghouse turbines, past history of similar turbine disc cracking, and results of laboratory tests. This prediction method takes into account two main parameters: the yield strength of the disc and the temperature of the disc at the bore area where the cracks of concern are occurring. The higher the yield strength of the material and the higher the temperature, the faster the crack growth rate will be.

The staff has evaluated the data submitted by the applicant and, in addition, performed independent calculations for crack growth and critical crack size. NRC staff concludes that St. Lucie Unit 2 may be safely operated until the first refueling outage, at which time the LP turbine discs should be inspected.

Inservice inspection will include UT of the bore and keyway areas of each disc and MT and visual inspection of all accessible areas. The inspection interval has been selected using the criterion that any postulated crack must not be allowed to grow to a size greater than one-half of the critical crack size, assuming a conservative crack growth rate. The staff concludes that these provisions provide reasonable assurance that the probability of disc failure with missile generation is low during normal operation, including transients up to design overspeed.

Summary

We conclude that the total turbine missile risk from high and low trajectory missiles for the St. Lucie Unit 2 design is acceptably low so that the plant structure, systems, and components, important to safety are adequately protected against potential turbine missiles.

3.5.3 Barrier Design Procedures

In Section 3.5.3 of the Safety Evaluation Report (SER) the staff required the steam trestle, the exhaust fan shields, and the air intake area covers be designed using a ductility factor of 10 or less. The applicant has committed, in Amendment 7 to the FSAR, to design the structures using a ductility factor of not greater than 10. Based on this commitment and the fact that the design is within the state of the art, the staff considers its requirements will be met and the item is considered closed.

Missiles damage is also discussed in Section 3.5.1.3.

3.7 Seismic Design

3.7.2 Seismic System and Subsystem Analysis (Structural Engineering Evaluation)

Section 3.7.2 of the St. Lucie 2 SER had a staff requirement that to prevent collision at structures during an earthquake, the displacements for structures on separate mats be combined as the absolute sum. The applicant has provided evidence that the space provided between structures is in excess of that required for the absolute sum of the calculated structural deflections for each structure due to the postulated earthquake. Therefore, no collision of the structures is anticipated. The designed capacity meets the staff requirements; therefore, the item is considered closed.

3.7.3 Seismic Subsystem Analysis (Mechanical Engineering Evaluation)

In our Safety Evaluation Report, item (3), "Non-NSSS Seismic Category 1 Piping Systems," we stated that the methods discussed by the applicant to handle relative seismic displacements in Category 1 piping systems were not considered acceptable. Subsequent to the issuance of the SER, the applicant, at our request, provided further justification and clarification of this issue. The following is our evaluation of the applicant's information.

The seismic displacement of piping supports located in structures on separate mats are computed by the square root of the sum of the squares summation of maximum response spectra displacements. The maximum response spectra values are based on enveloping maximum response spectra displacements of each structure. This methodology will not, in general, result in the most conservative displacements and was, therefore, not considered acceptable. However, the applicant has provided a comparison of the design values based on the above methodology with the maximum expected displacements obtained by the absolute summation of the time history displacements of the two buildings. These comparisons have been provided for typical piping systems traversing the reactor building and the reactor auxiliary building. The time history displacements values are found to be less than the St. Lucie Unit 2 design values for the typical cases provided in the comparison.

Based on this comparison of the maximum expected differential movements of the Category 1 piping supports during a seismic event using the absolute summation of time history displacements with the SRSS summation of maximum response spectra displacements, the specific seismic displacement design values developed for St. Lucie Unit 2 are acceptable.

The applicant has provided a list of all the systems which, because of their configuration, were not designed by the above methodology. The staff has reviewed this list and the basis for analysis omission supplied by the applicant, and has determined that the omission of a relative seismic displacement analysis for these systems is acceptable.

3.8 Design of Category I Structures

3.8.4 Other Category I Structures

Section 3.8.4 of the St. Lucie 2 SER indicated that the evaluation criteria of the masonry walls did not meet the requirements of the staff. The applicant has committed to incorporate the SEB positions into their evaluation criteria. The evaluation of the masonry walls is scheduled to start in late November and is expected to take approximately six months to complete. The results of this evaluation will be submitted for review at that time. The results of the review and any necessary repairs to the walls will be reported in a supplement to the SER.

4 REACTOR

4.2 Fuel System Design

4.2.1 Design Basis

4.2.1.1(d) CEA Fretting Wear

Fuel assembly guide tubes that are to be rodded with control element assemblies (CEAs) will have stainless steel sleeve inserts which will provide relatively resistant barriers to fretting. This guide-tube wear remedy will, however, adversely affect the CEAs by exposing the CEA Inconel-625 cladding to a harder wear surface. The applicant has stated (Ref. 1) that fretting wear of the CEA cladding will be evaluated on the basis of the stress and strain criteria given in the FSAR. An explicit fretting wear limit has not been provided, but FPL has stated that the CEA cladding will be required to withstand the mechanical loadings imposed during normal operation and anticipated operational occurrences.

We conclude that the description above constitutes an acceptable design basis inasmuch as it provides protection against gross CEA deformation though it will not guarantee hermiticity. Since unexpected CEA perforations might go undetected, hermiticity of the CEA is not a sufficient nor necessarily achievable design basis to ensure CEA reactivity inventory (see SER Section 4.2.1.1(j) for CEA surveillance requirements).

4.2.1.1(g) Axial Growth

Insufficient axial clearance for CEA growth resulting from irradiation-induced and temperature-induced elongation can create a potential for CEA or fuel assembly damage (see Ref. 2 for a discussion on such an occurrence) due to the impacting loads between CEAs and fuel assembly guide tube plugs. Of most significance, such a situation could lead to loss of CEA cladding integrity and loss of the poison inventory. Consequently, it is necessary that CEA axial growth be accommodated to prevent mechanical interference.

The applicant has not specified an explicit CEA axial growth design basis, but has stated (Ref. 1) "There is no criterion for axial growth per se; however, adequate clearances are maintained on...control element assemblies...to ensure functionability for their respective lifetimes." We conclude from this statement that the design basis is indeed to prevent mechanical interference. Moreover, FP&L has also stated (Ref. 3) "...under adverse design conditions a clearance of greater than zero shall be maintained." Consequently, we find this design basis and limit to be reasonable and adequate.

4.2.1.2(g) Mechanical Fracturing

Mechanical fracturing of a fuel rod could potentially arise from an externally applied force such as a hydraulic load or a load derived from core-plate motion. To preclude such failure, the applicant has stated (Ref. 3) that fuel rod fracture stress limits shall be in accordance with the criteria given in Table 9-1 of CENPD-178, Revision 1 (Ref. 4)

The review of CENPD-178, Revision 1, and the criteria given in Table 9-1 are being performed by a contractor (EG&G, Idaho) who will complete the review in January 1982. Following that review, we will be able to determine that acceptability of the mechanical fracture design stress limits. Since Part C of Reference 3 subrogates the mechanical fracturing discussion given in Section 4.2.3.3(e) of the St. Lucie 2 FSAR, FP&L should amend that section of the FSAR accordingly. Consequently, we will report on the resolution of these issues at a later date.

4.2.1.3(a) <u>Fragmentation of Embrittled Cladding</u>

Our SER pointed out that appropriate limits (2200°F peak cladding temperature and 17% local cladding oxidation) were used for the St. Lucie 2 LOCA analysis, but that criteria were not provided for other accidents. The applicant has addressed (Ref. 1) this subject and has provided an analysis (see Section 4.2.3.3(a) below). Since the analysis shows considerable margin based on experimental data, FP&L does not wish to develop specific limits that, in this case, would provide more precision than is required. We thus find that it is practical in this case to perform the evaluation without specifying a numerical limit.

4.2.3 <u>Design Evaluation</u>

4.2.3.1(h) <u>Rod Pressure</u>

According to CE, the assumption of 3% to 15% helium release from burnable poison pellets was based on a conservative point of view and a somewhat arbitrary choice for bounding (a) the 5% helium release from an early experiment (Ref. 5) and (b) a measurement from an undesignated CE NSSS reactor. Based on preliminary results, the rod pressure is expected to remain below the system pressure for a helium release of 9% (the average of 3% to 15%).

A literature search (Refs. 6, 7, and 8) revealed that observed maximum releases were never more than 6%. Furthermore, the average operating temperature of Al_2O_3-B_4C pellets is about 500°C (Ref. 8), which corresponds approximately to 3% release according to Figure 13 in Reference 7. We, therefore, expect that the applicant will be able to show that the rod pressure remains below the system pressure in St. Lucie 2. We will report in a subsequent supplement on our final evaluation of the St. Lucie 2 BPR pressure when the applicant's analysis is completed.

4.2.3.2(f) <u>Cladding Rupture</u>

In Section 1.8 of the SER, item (14) lists supplemental ECCS calculations as a confirmatory item. This item should have been considered resolved since FP&L has submitted such a calculation for St. Lucie 2 in a letter dated September 3, 1981 and the staff found the information provided on supplemental ECCS calculations as adequate.

4.2.3.3(a) Fragmentation of Embrittled Cladding

Some non-LOCA accidents (steam-line break, locked rotor, and CEA ejection) may lead to departure from nucleate boiling (DNB) and produce high cladding temperatures. The FSAR did not address continued coolability of such high-temperature accidents which might involve susbtantial cladding oxidation and embrittlement.

The applicant has now addressed (Ref. 1) this concern. Cladding time-vs-temperature information was provided for the three postulated accidents of interest, and this information was compared with experimental results (Refs. 9-15). We are familiar with the experimental results that were cited and agree that the time at elevated temperatures in the three accidents of concern are significantly less severe than those that would cause embrittlement and fragmentation which would challenge core coolability. Therefore, even without specifying an exact time-vs-temperature limit, we conclude that FP&L has demonstrated that coolability will not be lost due to fragmentation of embrittled cladding for non-LOCA events.

4.2.3.3(c) Cladding Ballooning and Flow Blockage

In Section 1.8 of the SER, item (14) lists supplemental ECCS calculations as a confirmatory item. This item should have been considered resolved since FP&L has submitted such a calculation for St. Lucie 2 in a letter dated September 3, 1981, and the staff found the information provided on supplemental ECCS calculations as adequate.

4.2.3.3(d) Structural Damage from External Forces

A preliminary analysis of the combined seismic and LOCA mechanical loads (Ref. 16) was recently received and is under review. The final assessment of the St. Lucie 2 fuel structural integrity under seismic and LOCA loadings will be submitted by the applicant in May 1982. We will report on our review of these submittals in a subsequent supplement.

4.2.5 Evaluation Findings

This supplement has resolved several of the issues that were described in the SER. The resolved parts cover paragraphs 4.2.1.1(d), 4.2.1.1(g), 4.2.1.3(a), and 4.2.3.3(a). Additional information has been provided on other issues in paragraphs 4.2.1.2(g), 4.2.3.1(h), and 4.2.3.3(d), but those have not been fully resolved.

4.4 Thermal-Hydraulic Design

4.4.7 Thermal-Hydraulic Comparison

The modifications to Table 4-1 are the results of changes in Amendment 7 to the FSAR and do not affect the conclusions reached in the SER.

Table 4.4-1 Reactor Design Comparison

	St. Lucie Unit 2	St. Lucie Unit 1, Cycle 3
I. Performance Characteristics:		
Reactor Core Heat Output (MWt)	2560	2560
System Pressure, psia	2250	2250
Minimum DNBR at Steady-State Full Power	2.64	2.37
Minimum DNBR Limit	1.20	1.30
Critical Heat Flux Correlation	CE-1	W-3
II. Coolant Flow:		
Total Flow Rate (gpm)	369947	369947
Effective Flow Rate for Heat Transfer (gpm)	356259	56259
Average Velocity Along Fuel Rods (ft/s)	15.1	15.4
Average Mass Velocity (10^6) lb/hr-ft^2)	2.45	2.53
III. Coolant Temperature, °F:		
Nominal Reactor Inlet	548	542
Average Rise in Core	50	50
IV. Heat Transfer, 100% Power:		
Active Heat Transfer Surface Area (ft^2)	56315	48860
Average Heat Flux (Btu/hr-ft^2)	151300	174400
Maximum Allowable Heat Flux (Btu/hr-ft^2)	443995	426699
Average Linear Heat Generation Rate (kW/ft)	4.43	6.0
Peak allowable Linear Heat Generation Rate (kW/ft)	13.0	14.68

4.7 References

1. R. E. Uhrig (FP&L) letter to D. G. Eisenhut (NRC), "Requests for Additional Information," Number L-81-403, September 14, 1981.

2. R. A. Clark (NRC) letter to W. G. Council (NNE), October 6, 1980.

3. R. E. Uhrig (FP&L) letter to D. G. Eisenhut (NRC), Number L-81-474, November 10, 1981.

4. "Structural Analysis of Fuel Assemblies for Seismic and Loss-of-Coolant Accident Loading," CE report CENPD-178, Revision 1, August 1981.

5. R. J. Burian, E. O. Fromm, and J. E. Gates, "Effect of High Boron Burnups on B_4C and ZrB_2 Dispersions in Al_2O_3 and Zircaloy-2," Battelle report BMI-1627, April 24, 1963.

6. G. L. Copeland, R. G. Donnelly, and W. R. Martin, "Irradiation Behavior of Boron Carbide," Nuclear Technology 16, 226 (1972).

7. "A Compilation of Boron Carbide Design Support Data for LMFBR Control Elements," Hanford Engineering Development Laboratory report HEDL-TME 75-19 UC 796, 1975.

8. R. O. Meyer, M. D. Houston, M. Tokar, and F. E. Panisko, "Control Material Behavior in Commercial Reactors," Transaction of American Nuclear Society (June 1977).

9. R. Van Houten, "Fuel Rod Failure as a Consequence of Departure from Nucleate Boiling or Dryout," NRC report NUREG-0562, June 1979.

10. S. Levine (NRC) memorandum to E. G. Case and R. Minogue, "Research Information Letter No. 17 PBF Single Rod PCM Test Results," May 5, 1978.

11. R. Van Houten (NRC) memorandum to M. Tokar, "Demonstrated Survivability of Zircaloy Cladding After Brief Exposure to Temperature of 1755°k and Above," February 23, 1981.

12. S. Shiozawa et al., "Evaluation on Oxidation of Zircaloy-4 Cladding During Rapid Transient in NSRR Experiments," JAERI-M-8187, March 1979.

13. T. Hoshi et al., "Fuel Failure Behavior of PCI-Remedy Fuels Under Reactivity Initiated Accident Conditions," JAERI-M-8836, May 1980.

14. "Semiannual Program Report on the NSSR Experiments-July to December 1979," JAERI-M-9011, September 1980.

15. T. Fujishiro et al., "The Influence of Coolant Flow on Fuel Behavior Under Reactivity Initiated Accident Conditions," JAERI-M-9104, October 1980.

16. R. E. Uhrig (FP&L) letter to D. G. Eisenhut (NRC), "Proprietary Data on Seismic and LOCA Fuel Analysis," Number L-81-471, November 4, 1981.

5 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.4 Component and Subsystem Design

5.4.3 Shutdown Cooling (Residual Heat Removal) System

In Section 5.4.3 of the SER, the staff requested that the applicant confirm that adequate core cooling can be maintained, following a moderate energy pipe break when in shutdown cooling, without relying on operator action for 20 minutes following the alarm signaling the event.

In a September 14, 1981 letter from R. E. Uhrig to D. Eisenhut, the applicant demonstrated that for the maximum postulated leak of 620 gpm, the plant operator has at least 20 minutes after the first alarm to identify and isolate the damaged train prior to any significant effect on core cooling. The RCS volume above the hot- and cold-leg piping includes the SG tubes, the SG inlet and outlet plenums, the reactor vessel upper head, the pressurizer surge line, and the pressurizer vessel for a total volume of approximately 4700 cubic feet. Taking credit for draining of only the SG active tubes and pressurizer volume required to cover the top of the heaters results in a reservoir of 2467 cubic feet. With a leak rate of 620 gpm, there is at least 20 minutes between the pressurizer low-level alarm (heater uncovery) and uncovery of the shutdown cooling system piping. Therefore, SDC system performance, coolant circulation through the reactor vessel, and core cooling are maintained, and this issue is resolved.

7 INSTRUMENTATION AND CONTROLS

7.2 Reactor Protection System

7.2.5 Logic Matrix and Logic Matrix Power Supplies

Background

In the St. Lucie 2 safety evaluation report (SER), dated October 9, 1981, we expressed a concern that the independence of the vital ac power buses supplying power to the RPS logic matrices was potentially compromised. We were subsequently informed by the applicant that (1) the independence of these buses is to be maintained through the use of qualified isolators which are presently undergoing tests to validate their qualification, and (2) that ultra isolation transformers associated with the vital instrument bus inverters will be installed. We then requested the applicant to provide a summary (types of tests, acceptance criteria, etc.) of the program to be used for testing the matrix power supply which supplies power to the RPS logic matrix. The applicant responded by letter (R. Uhrig to D. Eisenhut) dated November 10, 1981 with information describing the test program. Our evaluation is provided below.

Evaluation

The test involves simulating (with identical equipment) a typical RPS matrix including bistable trip units, bistable power supplies, matrix relays, matrix power supplies, and isolation circuitry. The testing will require the application of surge and fault test voltages in both the common and transverse modes. The fault test will consist of the application of 600 Vac 400 Vdc to the RPS logic circuitry. The surge test value to be applied will be 150 Vac. Based on the applicant's analyses, the highest credible ac and dc fault which could occur within the RPS cabinets is 480 Vac and 325 Vdc, respectively.

Ultra isolation transformers are being installed in the vital bus inverter system in order to attenuate any line surges which may pass through the inverter system into the RPS vital buses. The isolation transformer will be surge qualified in accordance with the guidelines of IEEE 472-1974, "Guide for Surge Withstand Capability Tests." These isolation transformers are presently undergoing testing. The acceptance criterion for this test is that the transformer limits the secondary voltage to a 50-volt pulse when applying a primary surge voltage ranging from 2.5 kV to 3.0 kV. Thus, the maximum credible surge voltage that could appear on the vital buses will be no greater than 50 volts. This is one third the surge test value (150 volts).

We have reviewed the applicant's test program which describes the RPS circuitry to be tested, the test setup, and the acceptance criteria for the application of both the surge and fault voltage and found it acceptable. The following are the acceptance criteria for the surge and fault testing:

1. That all circuits undergoing surge testing shall operate correctly (perform protective function) within their normal accuracy requirements before, during, and after the application of the surge voltage,

2. That for both the surge and fault applications the redundant 120 Vac vital buses supplying the matrix power supplies will not vary more than ±10%, and

3. That during and after a fault application the RPS trip logic will perform its protective function (trip actuation) when required.

Conclusions

Based upon our evaluation of the applicant's test program, we conclude that the test methodology will adequately demonstrate independence of the vital buses supplying power to the RPS logic matrices. The staff also concludes that the maximum credible fault and surge values to be used in the test program are acceptable. Therefore, based on our above evaluation and the satisfactory completion of the above test program, we conclude that the RPS design is acceptable.

Confirmatory Item

The applicant is required to confirm, at least 60 days prior to fuel load:

1. That the testing has been completed in accordance with the above test program,

2. That the acceptance criteria stated in the above evaluation have been met, and

3. That the ultra isolation transformers have been installed.

7.4 Systems Required for Safe Shutdown

7.4.5 Emergency Shutdown From Outside the Control Room

Refer to the commentary in Section 9.5.1 of this supplement, "Fire Protection."

7.5 Safety-Related Display Instrumentation

7.5.6 Loss of Non-Class 1E Instrumentation and Control Power Bus During Operation (IE Bulletin 79-27)

Refer to the commentary in Section 9.5.1 of this supplement, "Fire Protection."

8 ELECTRIC POWER SYSTEMS

8.3 Onsite Emergency Power System

8.3.1 Alternating Current Power Systems

The St. Lucie Unit 2 essential safety feature (ESF) motors, rated at 460 volts, are capable of accelerating the driven equipment to rated speed at 90% of the rated voltage. During the worst-case transient, voltage at the 460-volt bus drops to 84.3% (397 volts) when the containment fan cooler motor is started; however, this instantaneous voltage value recovers to 90% or higher in less than one second. We stated in the SER that the applicant must demonstrate that with a voltage dip below 90% (as low as 84.3%), the 460-volt essential features motors will start and accelerate their respective loads within the accident analysis time frame, with no long-term detrimental effects to the motor and without exceeding the motor heating limit.

The applicant in a letter dated October 27, 1981, submitted an analysis to demonstrate that the ESF motors have sufficient torque to accelerate the driven equipment with no motor damage occurring under the stated transient. The applicant's analysis was based on motor manufacturer-supplied speed torque curves for motor acceleration, at constant terminal voltage of 80% (which is less than the starting transient described above). From this curve, net torque (motor torque minus loading torque) was determined at 20% speed interval and the acceleration time of the motor was calculated to be 7.6 seconds. Comparing this acceleration time to the acceleration time of 10 seconds assumed in the accident analysis shows that the motor is accelerated within a time period that will not impact the accident analysis. To assure that the motors are not damaged with 80% of normal voltage at the terminals during the starting transient, the motor acceleration time was compared to the safe stall time (the maximum allowable time at locked rotor current that the motor is allowed to see) of the motor. From the manufacturer's data, the safe stall time at 100% starting voltage is 11 seconds (hot start), which is sufficiently higher than the acceleration time of 7.6 seconds; therefore, motor damage will not occur. The safe stall time of the motor increases as a result of low starting voltage since the inrush current is less; therefore, the acceleration time of 7.6 seconds at 80% of normal voltage and motor-safe stall time is greater and therefore more conservative.

Based on our review of the above information, we conclude that the reduced voltage starting of the ESF motors does not impact the safety analysis or result in damage to the motors and, therefore, we find this to be acceptable.

8.3.1.2.6 Adequacy of Station Electric Distribution System Voltages

We stated in the SER that there was insufficient information to conclude that the applicant's design conforms to BTP PSB-1, and additional information was required to complete our review. The applicant in a letter dated October 27, 1981 provided the additional information. The following items address our evaluation of the St. Lucie Unit 2 design for conformance with the above corresponding position numbers.

Position 1 - Second Level Undervoltage or Overvoltage Protection With a Time Delay

There are two redundant and independent emergency buses, and each has two levels of undervoltage protection: (1) loss of power and (2) degraded grid voltage. The scheme for the first level of undervoltage relays at 4.16-kilovolt buses consists of one CV-2 inverse time voltage relay for each Class 1E division set at 79% rated voltage with a 12-second time delay.

The second level of undervoltage protection is applied at 4.16-kilovolt as well as 480-volt safeguard buses. Each Class 1E 4.16-kilovolt volt bus is provided with three definite time relays set at 92.5% with a 10-second time delay. The three undervoltage relays will generate a trip signal using two-out-of-three logic. The relay logic actuates the control room annunicator to alert the operator to a degraded voltage condition. The subsequent occurrence of a safety injection signal would immediately separate the Class 1E system from the offsite power system automatically.

At the 480-volt level, a set of three definite time relays are provided in a two-out-of-three coincident logic arrangement for each Class 1E division. These relays will be set at 90% of 480 volts which corresponds to 94.7% of (460 v) motor nameplate voltage. The output of these relays will actuate CV-2 inverse time relays on the 4.16-kilovolt bus which will separate the Class 1E system from the offsite source in accordance with the selected time dial setting in approximately 20 seconds should the operator fail to restore system voltages. The above is in accordance with position 1 and is acceptable.

Position 2 - Interaction of Onsite Power Sources With the Load Shed Feature

The load shedding undervoltage relays are disconnected during diesel generator load sequencing and remain disconnected while the diesel generator breaker is closed to assure that inadvertent load shedding of safety-related loads does not occur while the diesel generator is supplying power to them. The load shedding relays are automatically reinstated into the load shedding circuit when the diesel generator breaker is opened. This is in accordance with position 2 and is acceptable.

Position 3 - Optimization of Voltage Levels of the Safety-Related Buses

The applicant has demonstrated by analysis that the transformer tap settings have been fully optimized for St. Lucie Unit 2. The electrical distribution system was analyzed to determine optimum safety-related bus voltages when operating from the unit auxiliary transformer or directly from the grid through the startup transformers. The analysis considered variations in main generator or switchyard voltages along with maximum and minimum expected plant load on the 4.16-kilovolt bus, the 480-volt power centers, the 480-volt motor control centers, and 120-volt/208-volt power panels connected to the power center buses. The results of these analyses have demonstrated that all Class 1E loads are capable of being started and continuously operated over the expected grid voltage range. All voltages on the Class 1E system will remain above the minimum acceptable design conditions with the exception of panel PP247 at 120-volt ac level. The applicant has committed to correct the occurrence of unacceptably low voltage on panel PP247 prior to plant operation by load redistribution or other means such that under the defined operating conditions voltages at all 120-volt ac power panels remain above 90% of 120-volt ac. We find this commitment to be acceptable, and we will verify the implementation of the design modification during our site visit.

The worst-case starting transient was also analyzed for the St. Lucie Unit 2 design. This consists of starting the largest non-Class 1E condensate pump motor on the most heavily loaded bus supplied from the startup transformer with switchyard voltage at the design minimum of 230 kilovolts. The results of this analysis demonstrated that following the starting transient, voltage on all Class 1E buses remain at values above the acceptable design limits, and no spurious actuation of the undervoltage relays will occur to separate the class 1E buses from the offsite power source. This is in accordance with position 3 and is acceptable.

Position 4 - The Analytical Techniques and Assumptions Used in the Voltage Analyses Must be Verified by Actual Measurement

The applicant has committed to perform a test, prior to fuel loading, to verify that the analytical method used for calculating the voltages at all distribution levels are valid. We find this acceptable.

Conclusion

Based on our evaluation of the information provided by the applicant, we conclude that staff positions 1, 2 and 3 of BTP PSB-1 have been met by the applicant and are acceptable. In regard to position 4, the applicant's commitment for correlating the measured values with the analysis results prior to fuel loading is also acceptable. We will verify the implementation of this commitment and the adequacy of the results obtained during our site visit.

8.3.3 Fire Protection

Refer to the commentary in Section 9.5.1 of this supplement, "Fire Protection."

9 AUXILIARY SYSTEMS

9.5 Other Auxiliary Systems

9.5.1 Fire Protection

In Section 1.7 of the SER, item (9) lists fire protection as an outstanding issue. FP&L had formally committed to have their fire protection program meet Appendix A of BTP ASB 9.5-1 and Appendix R to 10 CFR Part 50; therefore, the staff considered this item as confirmatory. However, at the time of the SER issuance, the staff had not completed the review. As a result, this item remained open. Since the SER issuance, the staff completed its review of the FP&L-submitted documentation. Furthermore, meetings were held with FP&L to assure the staff understood the FP&L fire protection program commitments.

Based on these commitments, which need to be verified that they have been met, we find the St. Lucie 2 fire protection program to be acceptable.

10 STEAM AND POWER CONVERSION SYSTEM

10.4 Other Features of the Steam and Power Conversion System

10.4.7 Condensate and Feedwater System

In Section 1.8 of the SER, item (23) lists water hammer test as a confirmatory item. This item should have been considered resolved since FP&L has submitted the information on their proposed water hammer testing and the staff has met with FP&L and reviewed their proposed program and has found the FP&L-committed test program acceptable.

13 CONDUCT OF OPERATIONS

13.2 Training

13.2.1 Reactor Operator Training

The applicant submitted a description of the requalification and retraining programs for St. Lucie Unit 1 on January 6, 1981. The applicant has advised us that these programs also are applicable to St. Lucie Unit 2. We have reviewed these programs and found them to be in accordance with the requirements of TMI Action Item I.A.2.1, I.A.2.3, and I.A.3.1. Accordingly, we conclude that these programs are acceptable.

13.3 Emergency Planning

13.3.1 Introduction

The staff's evaluation of the applicant's emergency plans is provided in Section 13.3 of the St. Lucie Unit 2 SER, NUREG-0843, dated October 1981. The St. Lucie Unit 2 Emergency Plan as amended (Revision 10, September 1, 1981) was reviewed against the requirements of 10 CFR Section 50.47(b), Appendix E to 10 CFR Part 50, and the criteria of the 16 Planning Standards in Part II "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," NUREG-0654/FEMA-REP-1, Rev. 1, dated November 1980. The staff is awaiting the applicant's response to the items identified in the SER as requiring resolution.

In correspondence to the Chairman of the NRC dated November 17, 1981, the ACRS expressed a concern over the rapid growth in population around the St. Lucie site subsequent to issuance of the CP for Unit 2, and requested the staff to take the special nature of this site (i.e., possible future increases in population density that might warrant additional measures) into consideration as part of its evaluation of the emergency plan. The following addresses the ACRS' concern.

Current regulations require the NRC to assure the adequacy of emergency planning and preparedness throughout the operating lifetime of a licensed operator. The NRC is currently conducting an Emergency Preparedness Implementation Appraisal program in order to verify that licensees have attained an adequate state of emergency preparedness. The Federal Emergency Management Agency (FEMA) is concurrently reviewing and evaluating State and local plans in accordance with the Memorandum of Understanding with the NRC.

In addition, 10 CFR 50.54(t) requires power reactor licensees to review and update their emergency plans every 12 months, document the findings, and retain the records for five years. The areas of plan to be reviewed are also specified in 50.54(t), and include the emergency plan's "capabilities." If any of the key parameters have changed to the extent that the emergency plan's effectiveness could no longer be assured, under 10 CFR 50.54(q), the licensee would have to submit proposed changes which would reestablish the effectiveness of the plan. For example, if the demography around a plant has changed so that the plan's evacuation time estimates are affected, revisions to the plan would be required to reflect appropriate estimates. In the case of the St. Lucie facility, the NRC is requesting (refer to Sections 1.9, item (1) and 2.1.3 of this supplement) the licensee to submit updated population estimates every five years, including transient population estimates, out to a distance of 10 miles. The NRC is also requesting updates of population to a distance of 50 miles when new census estimates become available every 10 years. Of course, NRC will rely on FEMA's assessment in judging the continued adequacy of the offsite plans given any changed conditions.

With regard to offsite emergency preparedness, the State of Florida Radiological Emergency Response Plan has been reviewed by FEMA Region IV, and is currently being revised by the State of Florida to resolve deficiencies identified by FEMA Region IV. A joint emergency response exercise, designed to determine the onsite and offsite emergency response capabilities, is scheduled for February 11, 1982.

The final NRC approval of the state of emergency preparedness for the St. Lucie site will be made following implementation of the revised emergency plans to include development of procedures, training and qualifying of personnel, installation of equipment and facilities, and a joint exercise involving participation by the response organizations (site, State and local).

13.5 Plant Procedures

13.5.2 Operating and Maintenance Procedures

1. General

We have reviewed the description of the applicant's plan for development and implementation of operating and maintenance procedures as described in Amendment 7 to the Final Safety Analysis Report (FSAR) for St. Lucie Plant Unit 2. The objective of this review was to determine the adequacy of the applicant's program for assuring that routine operating, off-normal, and emergency activities are performed in a safe manner. In determining the acceptability of the applicant's program, the following criteria and guidance were used:

a. 10 CFR Part 50, §50.34(a)(6) and (10) and §50.34(b)(6)(iv) and (v)

b. The guidance of Regulatory Guide 1.33 and ANSI/ANS 3.2-1981, Sections 5.2 and 5.3

c. NUREG-0660, TMI Action Plan, Item I.C.8, Selected Emergency Procedures for NTOLs and I.C.9, Long-Term Program for Upgrading of Plant Procedures

d. NUREG-0737, Clarification of TMI Action Plan, Item I.C.1, Guidance for the Evaluation and Development of Procedures for Transients and Accidents.

e. NUREG-0799, Draft Criteria for Preparation of Emergency Operating Procedures.

2. Discussion

The applicant has described in the FSAR a program to assure that all activities that affect safety-related structures, systems, and components are to be conducted in accordance with detailed, written, and approved procedures meeting the requirements of Regulatory Guide 1.33, Revision 2, dated February 1978, "Quality Assurance Program Requirements (Operation)," and ANSI 18.7-1976/ANS 3.2.

The applicant uses the following categories of procedures for operations performed by licensed operators in the control room:

a. Operating Procedures

b. Off-normal and Emergency Procedures

Other operating and maintenance procedures are included in the following categories:

a. Administrative Procedures

b. Chemistry Procedures

c. Emergency Plan Implementation Procedures

d. Environmental Test Procedures

e. General Maintenance Procedures

f. Health Physics Procedures

g. Instrument and Controls Department Procedures

h. Letters of Instruction

i. Maintenance Procedures

j. Preoperational Procedures

k. Security Procedures

l. Quality Instructions

The applicant has also committed to completing the above procedures approximately six months prior to initial fuel load.

3. Conclusions

We conclude that the applicant's program for developing operating and maintenance procedures meet the relevant requirements of 10 CFR Part 50 and are acceptable. This is based on the applicant's procedures meeting the guidelines of Regulatory Guide 1.33 and ANSI 18.7-1976/ANS 3.2. The applicant's program for reanalysis of transients and accidents and for the development of upgraded emergency procedures based on the reanalysis is contained in Section 22, Items I.C.1 and I.C.8.

15 ACCIDENT ANALYSIS

15.10 Limiting Accident

15.10.6 Anticipated Transients Without Scram

This subject is described in NUREG-0843, "Safety Evaluation Report Related to the Operation of St. Lucie Plant Unit No. 2," October 1981. The emergency operating procedures for ATWS will be part of the procedure development discussed for TMI Item I.C.8 and will be addressed in a later supplement to the SER.

15.10.8 Station Blackout

The station blackout event is postulated to occur from a loss of offsite power followed by failure of both standby diesel generators to start. This event, which follows multiple failures of safety-grade equipment, was included into the plant's licensing basis as part of the appeal board's decision in ALAB 603.

To evaluate this event, the staff has requested the applicant to provide information on plant system response, dc power source adequacy, and emergency procedure adequacy. Our findings in these areas are presented below.

System Response

The event is initiated by the loss of all offsite ac power followed by failure of the onsite diesel generators. As a result of the loss of power to the reactor coolant pumps, the applicant's analysis assumes that an automatic reactor trip signal is generated by the reactor protection system (RPS) on low reactor coolant system flow, as measured by steam generator delta-pressure. A reactor trip is also generated by the interruption of power to the reactor trip breakers which release the CEAs to drop into the core, shutting down the reactor. There is no return to criticality during this event.

Following coastdown of the reactor coolant pumps, flow through the reactor is maintained by natural circulation. Heat is transferred to the secondary system through the steam generators. Since the turbine and condenser will not be available following loss of offsite power, heat will be rejected through use of the atmospheric steam relief and safety valves.

This event was modeled using the CESEC III computer code, which models the two-phase conditions which are expected to occur. The staff is currently reviewing CESEC III and will require that any changes imposed by the staff be incorporated into this analysis. The analysis was carried out for a period of 4 hours which the staff agrees is a reasonable period in which to expect restoration of ac sources.

Since the event is initiated by loss of secondary heat sink and forced circulation, heatup and pressurization of the reactor coolant system will occur, with a maximum RCS pressure of 2541 psia obtained 6 seconds into the event. The pressure transient is terminated by action of the safety-grade pressurizer power-operated relief valve or safety valves. Since RCS pressure is maintained within 110% of design pressure, the staff finds this response acceptable.

The staff has reviewed the instrumentation and controls which will remain available on dc power sources and finds that they are sufficient to monitor and maintain the plant in a safe condition. The primary system which will be required during the course of this event is the auxiliary feedwater system. Initiation of auxiliary feedwater will occur on a low SG water-level signal 2 seconds into the event. Of the three auxiliary feedwater pumps, only the turbine-driven pump will be available. This pump can supply water to either or both steam generators at a total capacity of 500 gpm. All valves and controls associated with the turbine-driven pump are dc-powered from redundant station batteries. Neither the pump oil system nor the speed governor require ac power. The turbine pump and associated feedwater system can be automatically operated by opening and closing the discharge valves from the turbine-driven pump on low- and high-water level signals, respectively, in the steam generator. Manual operation is also available from the control room. All control circuitry is dc-powered. Water to the auxiliary feedwater system is provided from the condensate storage tank, which has a capacity of 400,000 gallons. Of this volume, only 180,000 gallons is required to bring the plant to hot standby and remain at hot standby condition for 4 hours.

Since no reactor coolant system makeup is available, some voiding in the upper head is predicted to occur due to primary system losses and thermal contraction. Analysis provided by the applicant calculated maximum voiding to be 1076 cubic feet which occurs 3.5 hours into the event. After this time, the discharge of borated water from the safety injection tanks prevents additional void growth. The void remains above the inlet to the hot legs and calculational results show that core cooling will be maintained by natural circulation.

Since primary system pressure limits are not exceeded and core cooling is maintained throughout this event, the staff finds that the plant system response is acceptable for total station blackout.

We conclude that the applicant has adequately analyzed the behavior of the plant during a station blackout, has demonstrated the ability of the plant to operate safely through such an event, and has established a basis for operator actions during the blackout period.

<u>DC Power Source Adequacy</u>

The Class IE direct current power system for St. Lucie Unit 2 is comprised of two redundant and independent 125-volt batteries with their associated battery chargers and distribution panels.

Sufficient capacity is provided in the Class IE subsystems to ensure the performance of all necessary instrumentation, as well as all dc-operated valves and controls associated with systems that are required for safe shutdown of the reactor.

To assure that sufficient battery capacity exists to accommodate the station blackout event, the applicant provided a battery-load profile for a 4-hour duration. This load profile was based on the maximum load on the dc bus and assumes that after 30 minutes into the event, the operator sheds certain unnecessary loads on the batterys. The loads shedded are comprised of nonsafety-related loads which have no mitigating functions during this event.

Based on our review of the information provided by the applicant, we conclude that the station batteries for St. Lucie Unit 2 have sufficient capacity to supply the required loads for four hours during the station blackout event and we find this to be acceptable. In addition, it has been determined that based on previous testimony before the St. Lucie Unit 2 hearing board and additional information provided by the applicant, that there is reasonable assurance that one of the three offsite power sources or one of the onsite diesel generators can be reinstated within four hours. Therefore, the applicant's demonstration that the station batteries provide four hours of capacity is acceptable.

Emergency Procedure Adequacy

The applicant submitted a draft version of the St. Lucie Unit 2 station blackout procedure on October 26, 1981. The staff reviewed these procedures for technical adequacy and human factors considerations. Staff comments on the technical content of the procedure were provided to the applicant in a meeting on October 30, 1981. The primary staff concern was that the procedure called for maintaining a 10°F subcooling margin using instrumentation with a ±10°F accuracy. Comments on human factors concerns for the procedures were given to the applicant in a meeting on November 13, 1981. The procedures were also reviewed by the NSSS vendor, Combustion Engineering. In a letter from R. E. Uhrig to D. G. Eisenhut dated November 19, 1981, the applicant committed to resolve the staff's and the vendor comments on the technical steps of the procedures and to incorporate human factors considerations that are acceptable to the staff by March 31, 1982. The final plant-approved station blackout procedures will then be submitted for staff review. Based on this commitment, we conclude that this item has been resolved subject to confirmation of final documentation.

Based on the above discussion, the staff finds that St. Lucie Unit 2 has design features and procedures which will enable it to respond adequately to a station blackout event, and therefore meets the requirements imposed by the ALAB 603 decision.

18 REPORT OF THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

During its 259th meeting on November 12-14, 1981, the ACRS reviewed all aspects of the St. Lucie Plant Unit 2 application for an operating license. A copy of the Committee's report dated November 17, 1981 is included in Appendix B to this report. In this report, the Committee identified a number of items which are addressed in this supplement or will be addressed in a subsequent supplement to the SER. The following is a list of these items, the status of the staff's review of each, and the location of the staff's discussion of each.

(1) Emergency operating procedures for dealing with off-normal plant behavior that might develop during the operation of St. Lucie Plant Unit 2 addressed in Sections 15.10.6 and 22, Item I.C.1 and I.C.8.

(2) The applicant and the NRC staff periodically review the actual and projected population growth and, if required as a result of these reviews, plans for appropriate preventive or remedial measures could then be made in a considered but timely manner addressed in 2.1.3.

(3) The staff gives due regard to the special nature of this site in evaluating the final emergency plan addressed in 13.3.1.

(4) Before requiring instruments for inadequate core cooling indication, the NRC staff should develop a position regarding their utility. Under review by staff; discussed in Section 22, Item II.F.2 of this report.

22 TMI-2 Requirements

22.2 Discussion of Requirements

I.C.1 Guidance for the Evaluation and Development of Procedures for Transients and Accidents

Position

The position for this TMI item is described in NUREG-0843, "Safety Evaluation Report Related to the Operation of St. Lucie Plant Unit No. 2," October 9, 1981.

Discussion

This discussion is based on the staff review conducted since publication of NUREG-0843. In a letter from Darrell G. Eisenhut to the CE Owners' Group dated September 15, 1981, we identified our concerns about the approach taken by the CE Owners' Group in developing guidelines for emergency operating procedures. This letter referred to a meeting held on July 24, 1981 in which the staff concerns were discussed. The letter also stated our understanding of the meeting, that Combustion Engineering would revise its guidelines. Until these guidelines are accepted by the staff, we will use the technical guidelines described in NUREG-0843 as a basis for licensing St. Lucie Plant Unit 2. We will review selected emergency operating procedures and in a later supplement to the SER we will address the adequacy of incorporation of these technical guidelines into the emergency operating procedures.

I.C.8 Pilot Monitoring of Selected Emergency Procedures for NTOL Applicants

Position

The position for this TMI item is described in NUREG-0843, "Safety Evaluation Report Related to the Operation of St. Lucie Plant Unit No. 2," October 9, 1981.

Discussion

This discussion is based on the staff review conducted since publication of the SER (NUREG-0843). A meeting was held in Bethesda, Maryland on November 13, 1981 with the applicant, the staff, and a representative from CE to discuss the development of emergency operating procedures for St. Lucie. At the meeting, the use of the technical guidelines described in NUREG-0843 and human factors considerations for the development of procedures at St. Lucie were discussed. A tentative schedule for the development and review of emergency operating procedures was agreed upon. A firm schedule will be established in mid-December including the schedule for submission of emergency operating procedures, a meeting to discuss our initial comments of the procedures, a visit to a simulator to exercise the procedures, and finally the walk-through of the procedures in the St. Lucie Unit 2 control room. The results of our review will be addressed in a later supplement to the SER.

I.C.7 NSSS Vendor Review of Procedures

In Section 1.8, Item (18) lists emergency operating procedures (I.C.7) as an open item. This item should not have been listed as an outstanding issue but rather as confirmatory since FP&L has committed to having the NSSS vendor, CE, review the power ascension test procedures and all emergency procedures.

I.D.1 Control Room Design Review

This review is discussed in Appendix C.

II.B.3 Post-Accident Sampling Capability

Requirement

Provide a capability to obtain and quantitatively analyze reactor coolant and containment atmosphere samples, without radiation exposure to any individual exceeding 5 rem to the whole body or 75 rem to the extremities (GDC-19) during and following an accident in which there is core degradation. Materials to be analyzed and quantified include certain radionuclides that are indicators of severity of core damage (e.g., noble gases, iodines, cesiums and nonvolatile isotopes), hydrogen in the containment atmosphere and total dissolved gases or hydrogen, boron and chloride in reactor coolant samples in accordance with the requirements of NUREG-0737.

To satisfy the requirements, the applicant should (1) review and modify his sampling, chemical analysis, and radionuclide determination capabilities as necessary to comply with NUREG-0737, II.B.3, and (2) provide the staff with information pertaining to system design, analytical capabilities, and procedures in sufficient detail to demonstrate that the requirements have been met.

Evaluation and Findings

By Amendment 5 and letter dated September 8, 1981, the applicant provided a description of systems, equipment, and procedures to be used for sampling the reactor coolant and containment building following an accident resulting in core degradation. The applicant has committed to a postaccident sampling system that meets the requirements of Item II.B.3 in NUREG-0737. Compliance with the license conditions as indicated in the SER is shown below:

Condition 1: Compliance with the requirements of NUREG-0737, Item II.B.3 are presented in the following subsections:

a. The system is capable of obtaining an analyzing reactor coolant, containment sump, and containment atmosphere samples within 3 hours from the time a decision is made to take a sample.

b. Measurement of total dissolved gas concentration, dissolved hydrogen and oxygen concentration, boron concentration, and pH are done remotely by in-line monitoring. Radionuclide analyses and chloride analyses are performed on grab samples.

c. Reactor coolant and containment atmosphere sampling during postaccident conditions does not require an isolated auxiliary system to be placed in operation in order to use the sampling system.

d. Reactor coolant gaseous analysis is performed in a pressurized sample which is collected by isolating the sample vessel. The collected gases, which have been stripped from the liquid, are then directed through a float valve for moisture separation and circulated through hydrogen and oxygen analyzers.

e. The time required to obtain a reactor coolant chloride analysis has not been specified by the licensee. This item remains open.

f. The postaccident sampling station is designed to provide adequate radiation protection so that it is possible for an operator to obtain and analyze a sample without radiation exposures exceeding the criteria of GDC 19, assuming source terms given in Regulatory Guide 1.4, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors."

g. Reactor coolant boron analysis is performed with an in-line boron meter. Backup boron analysis is performed using atomic absorption techniques on a grab sample.

h. The system is designed for in-line monitoring with grab sampling as a backup. The equipment provided for backup sampling is capable of providing at least one sample per day for 7 days following onset of the accident and at least one sample per week until the accident condition no longer exists.

i. The identification and quantification of the activity for reactor coolant and containment atmosphere postaccident samples were not provided by the applicant. This item remains open.

j. The postaccident sampling system instrumentation is designed to cover adequate ranges, accuracies, and sensitivities to allow the operator to obtain pertinent data to describe the chemical status of the reactor coolant system. The range of the radiological sample analysis should be specified per item i. above.

k. Reactor coolant sample lines are of a diameter such that the rupture of a sample line will limit reactor coolant loss. The ventilation exhaust from the sampling station is filtered with a charcoal absorber. Reactor coolant purge flow is directed back to containment.

Condition 2: Sufficient shielding is provided to make it possible for an operator to obtain and analyze a sample with radiation exposures meeting the requirements of GDC-19, assuming Regulatory Guide 1.4 source terms.

Condition 3: The applicant will comply with the detailed requirements of Regulatory Guide 1.97 or to provide adequate justification on a case-by-case basis for the use of an alternate approach.

Condition 4: The postaccident sampling panel will be powered from power panel 2AB which is capable of being powered from the diesel generator in the event of a loss of offsite power.

Condition 5: The inboard isolation valves which are inaccessible for repairs after an accident are environmentally qualified for operation as containment isolation valve and are capable of being opened with a reliable power supply in the event of a loss of offsite power.

Condition 6: A failed fuel estimation procedure has not been submitted by the applicant. This item remains open.

Condition 7: The St. Lucie postaccident sampling system does not use high pressure carrier gas which could be injected into the reactor coolant system.

Condition 8: The reactor coolant dissolved oxygen level can be verified to be <0.1 ppm since the instrument meets the range identified in Regulatory Guide 1.97.

Condition 9: Periodic calibration is performed every six months. The post-accident sampling station is designed to function for six months under postaccident conditions without recalibration. System operability will be tested at a minimum frequency of six months, coinciding with the required six-month Emergency Plan sampling exercise. Such operability tests check the functioning of all aspects of the system technicians will be trained both in the classroom and in actual hands-on operations.

Based on the above evaluation, we determined that the provisions in the proposed postaccident sampling system, when completed, will partially meet the requirements of Item II.B.3 in NUREG-0737. However, the applicant has not provided adequate information regarding reactor coolant chloride analysis time, identification and quantification of reactor coolant and containment atmosphere activity and procedure for relating radionuclide gaseous and ionic species to estimate core damage. No information has been provided for the type of in-line instruments and analytical chemistry procedures and data supporting their applicability (accuracy and sensitivity) in the postaccident environment. To this extent the license conditions stated below are proposed.

License Conditions

Implementation of all of the requirements of Item II.B.3 in NUREG-0737 is not necessary prior to low power operation because only small quantities of radio-nuclide inventory will exist in the reactor coolant system and therefore will not affect the health and safety of the public. Prior to exceeding 5% power operation, the applicant must demonstrate the capability to promptly obtain reactor coolant samples in the event of an accident in which there is core damage consistent with the conditions stated below:

1e - Provided for a chloride analysis within 24 days after the reactor coolant sample is taken.

1i and j - Provide the capability to identify and quantify the activity for reactor coolant and containment atmosphere postaccident samples.

6 - Provide a procedure for relating radionuclide gaseous and ionic species to estimate core damage.

In addition to the above licensing conditions the staff is conducting a generic review of accuracy and sensitivity for analytical procedures and on-line instrumentation to be used for postaccident analysis. We will require that the applicant submit data supporting the applicability of each selected analytical chemistry procedure or on-line instrument along with documentation demonstrating compliance with the licensing conditions four months prior to exceeding 5% power operation, but review and approval of these procedures will not be a condition for full power operation. In the event our generic review determines a specific procedure is unacceptable, we will require the applicant to make modifications as determined by our generic review.

The license should be conditioned on the basis of the above findings.

II.B.4 Training for Mitigating Core Damage

The applicant has submitted an outline of a program for training in mitigating core damage. The program covers all of the training subjects specified in the INPO report STG-01, Revision 1, dated January 18, 1981. These INPO guidelines, in turn, are based upon the training program outlined in the letter from H. Denton to all power reactor applicants and licensees, dated March 28, 1980. The applicant's program provides for more than 100 hours of training. Our review of the applicant's program indicates that it meets the staff requirements of TMI Action Item II.B.4 and is therefore acceptable.

II.F.2 Instrumentation For Detection of Inadequate Core Cooling

Introduction

This supplement addresses: (1) ACRS comments on instrumentation for detection of inadequate core cooling (ICC) which were provided in the ACRS letter of November 17, 1981, "Report on St. Lucie 2," from Chairman J. Carson Mark to NRC Chairman N. J. Palladino (refer to Appendix B), and (2) the applicant submittals of additional information required to support the acceptability of the final ICC detection system.

We reported in the St. Lucie Unit 2 SER (NUREG-0843) that the applicant had committed to provide additional information as follows:

(1) qualification testing of the heat junction thermocouple system (HJTCS);

(2) environmental and seismic qualification of the in-vessel and out-of-vessel instrumentation equipment;

(3) modifications to emergency procedures;

(4) proposed changes to Technical Specification;

(5) description of ICC signal transmission, processing, and display equipment;

(6) a detailed description of the saturation margin monitor (SMM) system to be used during the first cycle; and

(7) a description of the CET processing and display to be used during the first cycle of operation of Unit 2.

Information on the first five items was to have been submitted in September 1981.

In the transmittal L-81-468, the applicant provided the additional information for Items (1) and (5), but deferred the submittal schedule for Item (2) to June 1982, and for Items (3) and (4) to "prior to fuel load." In addition, a revised description of the final SMM was provided. The procurement schedule for components of the final ICC system (Item 5) was addressed in the submittal L-81-474.

In addition, the applicant submittal L-81-510 dated December 1981, informed us that the final SMM system and the final CET processing and display system (Items 6 and 7) are now targeted for completion prior to fuel load, which precludes the need for an interim system.

Resolution of Comments in ACRS Report on St. Lucie

The ACRS, in their letter of November 17, 1981 to Chairman Palladino, "Report on St. Lucie Plant Unit 2," recommended resolution of concerns on instrumentation for detection of inadequate core cooling previously expressed in the ACRS letter to the Executive Director for Operations dated June 9, 1981.

The staff provided an initial response to the ACRS concerns in the memorandum for Chairman J. Carson Mark from William J. Dircks, Executive Director for Operations, dated July 10, 1981. These concerns may be summarized as follow:

(1) installation schedule including relation to the schedule for development, testing, evaluation, and qualification of reactor vessel level monitoring instrumentation;

(2) utility of the information provided by the ICC monitoring system as determined by accident analyses and development of emergency procedures to deal with various specific accident scenarios; and

(3) possible consequences of misleading information to the operator due to dynamic effects on level monitoring instrumentation as a result of improper attention to the first two items in an over-eager response to TMI.

With respect to the first item, the staff has provided details of the implementation status for vessel level monitoring instrumentation, including the HJTC system proposed for St. Lucie 2, in the Commission paper SECY 81-582 dated October 7, 1981. That paper addressed the testing programs to be completed in advance of staff approval of these systems and described our review program and review status to support our preliminary conclusions concerning the prospects for acceptability of the systems. The paper also recommended that the staff be given permission to delay the January 1, 1982 installation requirement on a case-by-case basis as warranted by the equipment development and procurement and installation constraints. Based on the status reported in the paper, the staff expects that this would result in installation of the systems on most plants (possible exceptions are B&W vintage PWRs) by the first refueling outage after January 1, 1983.

By letter dated November 16, 1981 the Commission has approved our scheduling recommendation for Westinghouse and CE designed reactors committed to the Westinghouse or CE vessel level monitoring systems. We believe that this schedule relief in conjunction with the information provided on the equipment development, testing, and evaluation program is responsive to and resolves the concerns of Item (1) above, to the extent possible prior to completion of our generic review.

With respect to the second item, as explained in the July 10 memorandum to Chairman Mark, evaluation of specific water level monitoring systems has included analyses of specific accident scenarios (e.g., Westinghouse NOTRUMP code analyses of small-break LOCA (WCAP-9753) events and the response of their dp system under ICC conditions; CE analyses of small-break LOCA scenarios (CEN-117); analyses to predict instrument test performance under simulated small-break LOCA conditions, etc.).

However, these scenarios are not all inclusive. In accordance with TMI-2 lessons learned recommendations and current (post-TMI-2) practice on all emergency procedures, guidelines and procedures are to be symptom oriented. All process signals indicative of ICC conditions (saturation margin, coolant inventory, coolant or fuel temperature, etc.) are useful to confirm the need for emergency operator actions. The staff has offered to meet with the ACRS to inform them of progress in our generic review of the level monitoring systems and in the development of associated guidelines for emergency procedures for detection and recovery from a condition of inadequate core cooling. Presently, that meeting is expected to take place in February 1982. The staff expects that this meeting will provide a basis for resolution of the second concern. In any case, emergency procedures relating to vessel water level instrumentation are not required to be in place prior to issuance of an operating license for St. Lucie 2.

With respect to the third item of concern, the staff agrees that the best available ICC monitoring systems (Westinghouse and CE) are not perfect. We are attempting to identify deficiencies, including any which are related to dynamic effects, and believe that once identified, they can be neutralized by design of the data processing and display systems coupled with proper operating instructions. This concern can be resolved by thorough testing and design evaluation. The staff will keep the ACRS informed on the results of our review.

Response to Additional Comments - ACRS Report on St. Lucie Plant Unit 2

Members Lewis and Plesset of ACRS have expressed the opinion that, before, not after requiring specific instrumentation to detect the onset of ICC, the NRC staff should develop a position regarding their utility. The position should be based upon accident analysis and risk assessment.

To place these comments in perspective, it should be remembered that the requirement is a product of the TMI Lessons Learned Task Force short-term recommendations in NUREG-0578 (July 1979) and subsequent related documents and was supported by most, if not all, of the organizations reviewing that aspect of the TMI accident (especially the ACRS which insisted upon the water level instrumentation). The need for the instrumentation was thoroughly examined in many ACRS and Commission meetings. There is no general disagreement today on its utility. The original implementation date for this additional instrumentation was January 1, 1981. This recommendation and concurrent recommendations and studies relating to accident analyses and emergency procedure development called for a symptom oriented approach and provision of diverse information to the operator as the basis for operator actions and to monitor plant status. On this basis, the staff believes that saturation margin, coolant level and inventory, and fuel cladding temperature (as inferred by coolant superheat) are all important parameters for evaluation of core cooling adequacy, and that there is no unique emergency procedure governing which parameter should be used to initiate operator actions and what parameters should be used to verify the effectiveness of these actions and to monitor the course of the event.

Since establishment of the II.F.2 requirement, staff effort has been directed to development of acceptable instrumentation and the earliest feasible implementation of an ICC monitoring system which is consistent with objectives of the lessons learned recommendations. While a rigorous mathematical risk assessment evaluation was not a part of the decision process in developing this requirement, it seems clear that the cost of installation (both dollars and dose) is greater where backfits are required (more backfits are required when the definition of specific instrumentation is delayed), and that the benefits derived from risk reduction after installation of the system are a function of the useful life remaining for those operating reactors which must be backfitted. Therefore, there are advantages to be derived from the earliest feasible implementation consistent with development of acceptable systems, and that has been the staff goal since the lessons-learned need for the system was established.

In view of the advanced status of implementation of these systems and the earlier decisionmaking process described above, the staff does not believe that consideration of multiple additional accident scenarios (aside from the development of guidelines for emergency procedures) or risk assessment analyses would be useful at this time.

Final ICC System

The final design description of the SMM differs from that provided in Amendment 5 of the FSAR and addressed in the staff's SER. The SMM signal inputs and ranges are:

Input	Range
pressurizer pressure	0-3000 psia
cold leg temperature	0-710°F
hot leg temperature	0-710°F
maximum UHJTC temperature of top three sensors (from HJTC processing)	200 - 2300°F
representative CET temperature	200 - 2300°F

The sensor inputs for the major ICC parameters; saturation margin, reactor vessel inventory/temperature above the core, and core exit temperature are processed in the two channel QSPPS and transmitted to the Safety Assessment System (SAS) for primary display and trending.

The applicant has further evaluated the need for an interim system and has determined that the most feasible approach to an acceptable interim monitoring system is to reschedule the final design CET and SMM systems for installation completion prior to fuel load.

The applicant has identified and committed to schedule milestones for implementation of the final ICC system as follows:

(1) All core exit thermocouples (CET) will be installed and readable in the final totally safety-grade system including the QSPDS cabinets by initial criticality. As a target a minimum of four CET'S/QUADRANT will be functional by core load and readable from the QSPDS cabinets.

(2) The instrumentation necessary to monitor and display subcooling margin will be functional in the QSPDS cabinets by initial criticality with a target date of core load.

(3) The heated junction thermocouples (HJTC) will be functional in the QSPDS cabinets by June 1983.

In addition, the applicant has told us that he expects to complete the system preoperation checkout in September 1983 and to submit the test report in November 1983.

Staff Evaluation

We have completed our review of the additional information submittals for the ICC system and our conclusions follow:

(1) The documentation in accordance with NUREG-0737 Item II.F.2 and the committed schedule for implementation are acceptable for an operating license. However,

our review of the final design for acceptability will not be complete until after the installation and preoperational testing of the HJTC level monitoring system is complete.

(2) The interim ICC system consisting of the final CET and SMM instrumentation is acceptable for operation until approval of the HJTC system, but not later than January 15, 1984.

(3) Emergency procedures for operation of the interim ICC system must be submitted and approved prior to fuel load.

(4) Technical Specifications relating to the interim ICC system must be submitted and approved prior to fuel load.

The staff will assure that items (3) and (4) are accomplished prior to issue of the operating license. In addition, we will incorporate appropriate restrictions in the operating license to assure that the CET and SMM instrumentation are functional as committed prior to initial criticality and that the final ICC system is used for plant operation after January 15, 1984. Subject to these conditions, we conclude that St. Lucie Unit 2 conforms to the design requirements of NUREG-0737 Item II.F.2 and is acceptable for an operating license.

APPENDIX A

CHRONOLOGY OF RADIOLOGICAL REVIEW

(This chronology corrects and replaces the one in the SER in which several dates were duplicated. Furthermore, chronology since the issuance of the SER has been added.)

March 24, 1980	Applicant forwards OL application with FSAR to NRC.
March 31, 1980	Applicant provides status of response to an earlier NRC request for evacuation time estimates.
April 8, 1980	Applicant forwards 1979 Annual Financial Statement to NRC.
April 10, 1980	Letter to applicant requesting technical basis for the use of Ameron NUKEM 750 caulk as an expansion joint filler inside the containment.
April 18, 1980	Letter to applicant requesting additional information on Safeguards Contingency Plan.
April 21, 1980	Letter to applicant discussing piping supports attached to masonry walls not designed to carry loads. Request information on acceptance criteria for analysis and design.
April 22, 1980	Applicant responds to NRC April 10, 1980 letter requesting information on NUKEM 750 as a qualified caulk. Final submittal expected July 30, 1980.
April 30, 1980	Letter from applicant containing a discussion of the baseline QA document review program.
May 5, 1980	Meeting with applicant to discuss baseline QA documents and various implementation procedures. Meeting also covered status and details of applicant review effort, examples of results and schedule for completion.
May 7, 1980	Letter from applicant discussing Dresser Industries, Inc. relief and safety valve testing. Letter also discussed utility participation in a related EPRI test program.
May 20, 1980	Letter to BWR and PWR applicants discussing NRC decision to modify implementation plan in Section 4 of NUREG-0577 regarding adequacy of applicable support structures.
June 10, 1980	Applicant forwards revised security plan to NRC.

June 12, 1980	Letter to applicant forwarding organizational charts for NRR. Letter also discusses procedures for appealing staff positions.
June 13, 1980	Applicant forwards application to amend construction permit to reflect adjustments in facility and site ownership.
June 18, 1980	Applicant forwards Parts A and B of information requested in Regulatory Guide 9.2.
June 19, 1980	Applicant forwards Revision 1 to Safeguards Contingency Plan in response to NRC request, dated April 18, 1980, for more information.
June 25, 1980	Letter to applicant forwarding Commission memorandum and order containing decisions on petition from Union of Concerned Scientists regarding fire protection for electrical cables.
June 26, 1980	Letter to applicant forwarding statement of policy on requirements to be met for OL applications per NUREG-0660 and NUREG-0694.
June 30, 1980	Letter to applicant forwarding Federal Register notice regarding regional meetings to address Commission memorandum and order describing requirements for environmental qualification of electrial equipment installed in safety equipment.
July 2, 1980	NRC letter to all CP and OL applicants requesting information regarding plant vicinity evacuation times.
July 11, 1980	Letter to applicant requesting updated construction completion and fuel load dates to assist NRC in establishing licensing priorities.
July 13, 1980	Letter to applicant forwarding notice of receipt of additional antitrust information for simultaneous publication in Federal Register and listed newspapers.
August 1, 1980	Applicant forwards response to NRC letter, dated April 10, 1980, by providing technical basis for use of NUKEM 750 as a qualified caulk.
August 1, 1980	Letter to applicant forwarding Attorney General letter regarding additional antitrust advice pursuant to Section 105(c) of the Atomic Energy Act.
August 1, 1980	Letter to applicant forwarding draft of NUREG-0696, "Functional Criteria for Emergency Response Facilities." Proposed implementation schedule included.

August 25, 1980	Letter to applicant requesting submittal of ATWS emergency operating procedures for NRC review by October 19, 1980.
August 25, 1980	Letter to applicant requesting that information on chemical formulation and quantity of NUKEM 750 to be used as joint filler inside containment be provided by September 10, 1980.
August 26, 1980	Applicant submits information requested in NRC letter dated July 11, 1980 by providing current construction completion schedules. Facility to be ready for fuel load in November 1982.
August 26-28, 1980	Reactor coolant pump seal hot standby test conducted at site.
August 27, 1980	Meeting with applicant to discuss Unresolved Safety Issue A-12, "Potential for Low Fracture Toughness and Lamellar Tearing on Component Structures."
September 5, 1980	Letter to all licensees of operating plants, OL applicants and CP holders discussing clarification of TMI Action Plan.
September 10, 1980	Letter from applicant responding to NRC letter dated August 25, 1980 regarding the use of NUKEM 750 as an expansion joint filler inside the containment.
September 18, 1980	Meeting with applicant to review schedules for application tendering and NRC review.
September 18, 1980	Letter to applicant forwarding Amendment 1 to CPPR-144, incorporating conditions to alleviate loss of ac power in the event of station blackout.
September 18, 1980	Letter to applicant forwarding Revision 2 to plant security plan in response to utility request for return of superseded copies.
September 19, 1980	Letter to applicant forwarding errata sheets amending letter dated September 5, 1980 regarding preliminary clarification of TMI action plan requirements.
September 23, 1980	Letter from applicant advising NRC that FSAR has been forwarded to EG&G, ID, Inc. for acceptance review per NRC request. Also, applicant will address TMI items in FSAR by January 1, 1981.
September 29, 1980	Letter to applicant requesting additional information on the application for transfer of ownership to Orlando, Florida and Orlando Utilities Commission.

September 30 - October 2, 1980	Meeting with applicant and EBASCO at the site to review status of construction and projected fuel load date.
October 3, 1980	Letter from applicant informing NRC of organizational changes in QA and Advanced Systems and Technology Departments.
October 3, 1980	Letter from applicant discussing critical review areas and procedures for accelerated review of OL applications.
October 6, 1980	Letter to all power reactor licensees and applicants forwarding summary of August 27, 1980 meeting on Unresolved Safety Issue A-12, "Potential for Low Fracture Toughness and Lamellar Tearing on Component Supports."
October 10, 1980	Letter from applicant forwarding financial information requested by the NRC on September 29, 1980.
October 17, 1980	Letter to applicant confirming OL review schedule as discussed in September 18, 1980 meeting and October 3, 1980 letter. Construction completion is scheduled for December, 1983.
October 20, 1980	Letter from applicant acknowledging receipt of NRC letter dated August 25, 1980 regarding ATWS procedures.
October 23, 1980	Site visit to review initial test program and FSAR Chapter 14.
October 29, 1980	Applicant forwards security plan to NRC.
October 31, 1980	Letter to operating plant licensees, OL applicants and CP holders forwarding NUREG-0737.
October 31, 1980	Applicant informs NRC of status of compiling information for environmental qualification of safety-related equipment.
November 7, 1980	Letter to applicant stating that review of proposed use of NUKEM 750 caulk is complete and use of this material is acceptable.
November 12, 1980	Meeting with applicant to discuss Unresolved Safety Issue A-12, "Potential for Low Fracture Toughness and Lamellar Tearing on Component Supports."
November 13, 1980	Letter to all licensees of operating reactor plants, CP holders and CP applicants requiring that radiological emergency response plans be submitted within 60 days of January 2, 1981 and by applicants as part of FSAR.

November 14, 1980	Letter to applicant acknowledging receipt of June 13, 1980 letter regarding transfer of ownership. Approved transfer of ownership interest and amendment to CPPR-144.
November 17, 1980	Applicant forwards construction and startup monthly status report for October, 1980.
November 26, 1980	Letter to all power reactor licensees and applicants forwarding summary of November 12, 1980 meeting regarding implementation of guidance for Unresolved Safety Issue A-12, "Potential for Low Fracture Toughness and Lamellar Tearing on Component Supports."
November 26, 1980	Letter to all licensees of operating plants, OL applicants and CP holders providing generic clarification of NRC order dated October 24, 1980 on environmental qualification of safety-related equipment.
December 3, 1980	Letter from applicant forwarding preliminary test schedules for environmental qualification of safety-related equipment.
December 9, 1980	Letter to all licensees of operating reactor plants, holder of CPs and CP applicants forwarding Revision 1 of NUREG-0654/FEMA-REP-1 and summary of evacuation time estimate ratings.
December 11, 1980	Applicant forwards Amendment 0 to the FSAR.
December 11, 1980	Applicant forwards construction and startup status report for the month of November, 1980.
December 11, 1980	Letter from applicant requesting reactor operator hot license re-examination for a named person on January 28, 1981.
December 17, 1980	Applicant forwards revision to QA manual.
December 22, 1980	Letter to all licensees of operating plants, OL applicants and CP holders discussing control of heavy loads. Requests review per NUREG-0612.
January 9, 1981	Letter from applicant informing NRC that no new applications or requests for reactor facilities are planned before December 31, 1983.
January 14, 1981	Applicant forwards monthly construction and startup progress report for the month of December, 1980.
January 19, 1981	Letter to all licensees of operating plants, OL applicants and CP holders discussing program for environmental qualification of safety-related electrical equipment.

January 23, 1981	Letter to applicant forwarding results of operator license examination.
January 29, 1981	Letter from the applicant informing the NRC that changes have been completed ~~in transfer of ownership~~ per Amendment 2 to CPPR-144.
February 3, 1981	Letter to all licensees of operating plants, CP holders and OL applicants forwarding omitted paper from NRC letter dated December 22, 1980 regarding request for additional information on control of heavy loads.
February 6, 1981	Applicant forwards construction and startup program report to the NRC for January 1981.
February 9, 1981	Letter to applicant giving notification of acceptance of OL for safety review. Includes distribution requirements.
February 13, 1981	Applicant forwards additional copies of general information portion of OL application to NRC. Additional copies of FSAR, including Amendment 0, forwarded this date under separate cover.
February 18, 1981	Letter to all operating plants and CP holders forwarding clarification of TMI action plan item III.A.1.2 regarding upgrading of emergency support facilities.
February 19, 1981	Letter from applicant proposing meeting with NRC to discuss details and objectives of FSAR independent design review (IDR) pilot program.
February 23, 1981	Letter from applicant informing NRC that OL general information and FSAR distribution has been made per NRC request dated February 9, 1981.
February 26, 1981	Generic Letter 81-06 to all CP holders and OL applicants regarding 10 CFR 50.71(e), "Periodic Updating of FSARs," including legal status of FSAR, format and content requirements.
February 27, 1981	Letter from applicant requesting revision of application review schedule to reflect October 1982 projection for construction completion.
March 2, 1981	Meeting with applicant to discuss independent design review (IDR) pilot program.
March 3, 1981	Generic Letter 81-04 requesting review of current operations to determine capability to mitigate effects station blackout event. Also discusses prompt implementation of emergency procedures.

March 5, 1981	Letter to all licensees of operating plants and CP holders forwarding NUREG-0696, "Functional Criteria for Emergency Response Facilities."
March 9, 1981	Letter from applicant requesting formal approval of IDR program to provide significant reduction in application review time.
March 10, 1981	Letter from applicant providing results of tests conducted August 26-30, 1980 to demonstrate reactor coolant pump seal design adequacy during postulated station blackout conditions.
March 10, 1981	Letter to all licensees of operating plants, OL applicants and CP holders forwarding SECY-81-119 regarding environmental qualification of safety-related electrical equipment.
March 11-12, 1981	Meeting with applicant to review scope of safety review of ac power systems and containment heat removal system.
March 12, 1981	Letter from applicant responding to NRC letter dated November 25, 1980 regarding Commission memorandum and order pertaining to environmental qualification of electrical equipment. Requested information will be forwarded four months before expected issuance of full power license.
March 18, 1981	Letter to applicant stating that docketing date for OL application was February 17, 1981. Federal Register notice enclosed.
March 20, 1981	Applicant forwards status report of construction/ startup progress for the month of February, 1981.
March 23-24, 1981	Meeting with applicant, FEMA, state and local agencies to discuss NRC comments dated February 7, 1981 and March 9, 1981 on the emergency plan.
March 24, 1981	Meeting with applicant to discuss information needed to complete FSAR review.
March 27, 1981	Applicant forwards Amendment 1 to FSAR in response to NRC letter dated February 9, 1981 requesting additional information per the acceptance review.
March 27, 1981	Letter to applicant forwarding requirements for preservice inspection and testing of snubbers.
March 27, 1981	Letter to applicant forwarding request for additional information for OL safety review.

March 31, 1981	Applicant forwards report of construction/startup progress for the month of March 1981.
April 1, 1981	Letter from applicant forwarding 64 oversize P&IDs and flow diagrams in response to NRC request.
April 3, 1981	Letter to applicant requesting additional information for FSAR review of compliance with GDC 51.
April 4, 1981	Letter from applicant notifying NRC that required design information for emergency operations facility will be provided in a future FSAR amendment, in response to NRC request dated February 18, 1981. Also, information pertaining to minimum staffing for emergencies is expected to be submitted by June 1, 1981.
April 8, 1981	Letter to applicant with request for additional information from Materials Engineering Branch concerning preservice inspection program.
April 23, 1981	Meeting with applicant, Ebasco and Combustion Engineering to discuss auxiliary feedwater system.
April 24, 1981	Letter from applicant forwarding additional security measures for physical security plan.
April 24, 1981	Meeting with applicant to discuss preservice inspection program guidelines.
April 27, 1981	Letter from applicant forwarding FSAR Amendment 2, providing revisions to Chapter 15 and Appendix 15A, regarding accident analysis.
April 30, 1981	Letter from applicant forwarding magnetic data tape of hourly averages of meteorological data for September 1976 to August 1978, NRC data tape format and example of utility data.
May 1, 1981	Letter from applicant notifying NRC that preservice inspection and snubber testing requirements will be met in response to NRC letter dated March 27, 1981. Chapter 14 of FSAR will be revised to specify test program.
May 1, 1981	Letter from applicant informing NRC that response to NRC letter dated March 18, 1981 was provided during March 23-24 meeting. Response will be formalized in FSAR Amendment 3. Same procedures to be used to respond to future requests for additional information.
May 4, 1981	Letter to all licensees of operating plants and CP holders regarding qualification of inspection, exam and testing and audit personnel. Regulatory Guide 1.146 enclosed.

May 5, 1981	Generic Letter 81-21 concerning natural circulation cooldown.
May 5, 1981	Letter to applicant with request for additional information for FSAR review.
May 5, 1981	Letter to all licensees of operating plants and CP holders regarding engineering evaluation of H.B. Robinson reactor coolant leak of 6,000 gallons on January 29, 1981.
May 5, 1981	Meeting with utility to discuss operational QA program described in topical report FPLTQAR 1-76A.
May 5, 1981	Meeting with applicant and Ebasco to discuss draft of fire protection questions.
May 5, 1981	Meeting with applicant to review operational QA program per Revision 4 to QA topical report FPLTQAR-1-76A.
May 5, 1981	Meeting with applicant to discuss operational QA program as described in proposed Revision 4 to topical report FPLTQAR 1-76A. Applicant presented review schedule for baseline review of current QA Regulatory Guides.
May 6, 1981	Letter to applicant requesting additional information for Auxiliary Systems Branch FSAR review. Questions concern the effects of flooding on safety-related structures and the reactor coolant pressure leak detection system.
May 14, 1981	Letter from applicant requesting withdrawal of listed application for operator and senior operator licenses. Individuals require further training.
May 15, 1981	Letter to applicant requesting additional information for Chemical Engineering Branch safety review of fire protection program.
May 15, 1981	Meeting with applicant and Ebasco to review liquid pathway release analysis.
May 15, 1981	Meeting with applicant, Essex Corporation and Ebasco to review human factors aspects of control room design.
May 16, 1981	Letter to applicant forwarding request for additional information for Hydrology and Geotechnical Engineering Branch safety review.
May 19, 1981	Letter from applicant forwarding report of construction and startup program for the month of April 1981.

May 21-22, 1981	Meeting with applicant at the site to review response to Auxiliary Systems Branch request for additional information.
May 21-22, 1981	Site visit to discuss responses to NRC requests for additional information to expedite review of FSAR.
May 26, 1981	Letter to applicant forwarding Amendment 3 to CPPR-144 and related Federal Register notice. Amendment 3 adds certain antitrust conditions.
May 26, 1981	Letter to counsel to parties in NRC proceedings and other interested persons requesting comments on enclosed Federal Register notice pertaining to licensing requirements for OL applications.
May 26, 1981	Letter from applicant forwarding 2,042 oversize electrical, instrumentation, control and P&IDs referenced in Sections 1.7.1 and 1.7.2 of the FSAR.
May 26, 1981	Letter from applicant forwarding Amendment 3 to FSAR.
May 27, 1981	Meeting with applicant to discuss independent design review (IDR) pilot program technical evaluation report submittals.
May 29, 1981	Letter to applicant requesting confirmation of construction completion schedule, and quarterly updates. Letter also outlines basis for preliminary hearing schedule.
June 2, 1981	Meeting with Argonne National Laboratory to discuss FSAR review questions and drawing review items. Also discussed ANL role in preparing draft SER input.
June 3, 1981	Letter to all applicants for OLs and Cps, power reactor licensees, architect-engineers and reactor vendors forwarding Federal Register notice of meeting to discuss requirements for environmental qualification of safety-related electrical equipment.
June 3, 1981	Letter from applicant stating that response to Materials Engineering Branch requests will be provided August 1, 1981 for inservice inspection section, and June 15, 1981 for component integrity section. Also, response to Chemical Engineering Branch request will be provided June 26, 1981.
June 4, 1981	Generic Letter 81-23 to all OL and CP holders requesting copies of all Institute of Nuclear Power Operation (INPO) plant-specific evaluation reports for NRC appearances before the Advisory Committee on Reactor Safeguards.

June 8, 1981	Letter from applicant providing seismology information pertaining to May 5, 1981 meeting agreement.
June 9, 1981	Letter to applicant forwarding request for additional information for Radiation Protection and QA Branch safety reviews.
June 9, 1981	Meeting with applicant to discuss operator licensing on both units simultaneously.
June 11, 1981	Letter to applicant forwarding request for additional information for Meteorology Section FSAR review. Questions pertain to onsite meteorological measurements program since August 1978.
June 18, 1981	Letter to applicant providing additional guidance on TMI Action Plan Item 1.G.1 (Special Low Power Testing). Discusses requirement for natural circulation test and associated training descriptions in FSAR.
June 12, 1981	Letter to applicant proposing meeting to resolve open issues in enclosed Mechanical Engineering Branch draft SER input. NSSS vendor and AE should attend. Participants should be prepared to make binding commitments.
June 12, 1981	Letter to applicant forwarding Siting Analysis Branch request for additional information for FSAR review. Questions pertain to ownership of all mineral rights and easements to property.
June 12, 1981	Letter to applicant forwarding Materials Engineering Branch request for additional information for FSAR review. Questions pertain to design, assembly and operating conditions of low pressure turbine discs.
June 16, 1981	Letter from applicant forwarding construction and startup progress report for the month of May 1981. Also, target fuel load date confirmed in response to May 29, 1981 letter.
June 16-17, 1981	Meeting with applicant to discuss FSAR sections concerning equipment and floor drainage systems, high and moderate energy pipe analysis, flood protection wtih respect to pipe and equipment failures, and waterhammer testing.
June 17, 1981	Letter to applicant with Instrumentation and Control Systems Branch request for additional information for FSAR review.
June 17-18, 1981	Meeting with applicant to review responses to Power Systems Branch request for additional information.

June 18, 1981	Letter to applicant forwarding Seismic Qualification Review Team request for additional information pertaining to equipment qualification for seismic and hydrodynamic loads.
June 19, 1981	Meeting with applicant, Ebasco, Combustion Engineering and EG&G Idaho to discuss preservice inspection program.
June 24, 1981	Letter to applicant forwarding Reactor Systems Branch request for additional information for FSAR review.
June 29, 1981	Letter to applicant with Power Systems Branch request for additional information for FSAR review.
June 29, 1981	Letter from applicant forwarding FSAR Amendment 4.
June 30, 1981	Letter from applicant discussing dual licensability of operators. Operations and systems difference analysis report enclosed for official ruling.
June 30, 1981	Letter to applicant with Materials Engineering Branch request for additional information to complete FSAR review. Questions concern verification of ownership of mineral rights and easements on property.
June 30, 1981	Letter to applicant with Component Integrity Section (Materials Engineering Branch) draft SER input regarding vessel materials, pressure-temperature limits, vessel integrity and reactor coolant pump flywheel integrity.
June 30, 1981	Letter to applicant forwarding Containment Systems Branch draft SER input pertaining to heat removal system. Requests additional information on containment emergency sump design and water level monitor system.
July 6, 1981	Generic letter 81-23A advising that the submittals of plant-specific Institute for Nuclear Power Operations (INPO) are no longer necessary.
July 7, 1981	Letter from applicant expressing confidence that current projected fuel load date of October 1982 will be met.
July 7, 1981	Letter to applicant requesting additional information for Structural Engineering Branch OL safety review.
July 7, 1981	Meeting with applicant to discuss responses to Instrumentation and Control Systems Branch requests for additional information.
July 7-9, 1981	Meeting with applicant, Ebasco and Combustion Engineering to discuss facility design.

July 7-9, 1981	Site visit with BNL for confirmatory analysis of the shutdown cooling system piping.
July 9, 1981	Generic Letter 81-27 requesting that all emergency plans and implementing procedures be submitted, with pages marked to reflect privacy and proprietary material.
July 10, 1981	Letter to applicant requesting additional information for OL safety review.
July 13, 1981	Letter from applicant informing NRC that magnetic tapes containing meteorological data consistent with proposed Revision 1 to Regulatory Guide 1.23 have been delivered for NRC review.
July 13, 1981	Meeting with applicant and Combustion Engineering to discuss fuel failure criteria in analysis of accident and transient events.
July 15, 1981	Letter from applicant forwarding financial information and testimony on operational costs. Information will be incorporated into future amendment to FSAR.
July 16, 1981	Letter to applicant requesting additional information for OL safety review.
July 16, 1981	Letter to applicant requesting summary description of relevant investigative programs and interim measures for dealing with listed unresolved safety issues per NUREG-0606.
July 17, 1981	Letter to applicant requesting confirmation that prompt emergency notification system will be installed, including schedule for installation, system description and anticipated problems that may hinder implementation.
July 21, 1981	Letter from applicant advising NRC that responses to Equipment Qualification Branch questions on seismic and hydrodynamic loads will be submitted by November 30, 1981.
July 21, 1981	Letter from applicant forwarding report of construction and startup progress for the month of June 1981.
July 21, 1981	Meeting with applicant to discuss responses to NRC requests for additional information on FASR Chapter 14.
July 22, 1981	Site visit to evaluate the ALARA program.
July 23, 1981	Letter to applicant forwarding SER input for onsite ac power systems, including results from independent design review (IDR) program.

July 23, 1981	Letter from applicant forwarding Revision 4 to topical QA report.
July 27, 1981	Letter from applicant advising NRC of agreement to provide justification for not performing steam generator water hammer test. Preoperational test program will verify adequacy of design.
July 27, 1981	Letter from applicant forwarding "Comparability of St. Lucie Site and Liquid Pathway Generic Study From Standpoint of Liquid Pathway."
July 28, 1981	Letter to applicant forwarding request for additional information for Instrumentation and Control Systems Branch OL safety review.
July 28, 1981	Letter to applicant requesting additional information for Procedures and Test Review Branch OL safety review.
July 28, 1981	Letter to applicant forwarding Materials Engineering Branch SER input for listed Standard Review Plan sections.
July 28-31, 1981	Design audit of site structures conducted at Ebasco offices in New York.
July 30, 1981	Letter from applicant responding to Generic Letter 81-01 regarding qualification of inspection, exam and testing and audit personnel.
July 31, 1981	Generic Letter 81-16 discussing steam generator overfill problems.
August 4, 1981	Letter from applicant forwarding response to an NRC request for additional information.
August 5, 1981	Letter to applicant forwarding request for additional information for Thermal Hydraulics Section, Core Performance Branch OL safety review.
August 6, 1981	Letter from applicant forwarding response to generic letter on control of heavy loads. Guidelines in NUREG-0612, "Control of Heavy Loads," are addressed. Final report will be submitted by September 30, 1981.
August 6, 1981	Letter from applicant forwarding responses to an NRC request for additional information.
August 7, 1981	Generic Letter 87-29 discussing simulator examinations and requesting 1981 and 1982 schedules within 60 days.
August 7, 1981	Letter from applicant forwarding revised "Comparability of St. Lucie Site and Liquid Pathway Generic Study from Standpoint of Liquid Pathway."

August 10, 1981	Letter to applicant forwarding draft of Chemical Engineering Branch SER input for specific listed Standard Review Plan section.
August 11, 1981	Letter from applicant forwarding response to NRC request for additional information. Responses will be incorporated into an FSAR amendment.
August 12, 1981	Letter from applicant forwarding FSAR Amendment 5, including responses to NUREG-0737 and other specific questions.
August 14, 1981	Letter to applicant requesting additional information for Geotechnical Section, Hydrologic and Geotechnical Branch OL safety review.
August 14, 1981	Letter to applicant identifying areas where additional information is required regarding preliminary evacuation time estimates for area near facilities.
August 14, 1981	Letter from applicant forwarding additional information requested by NRC on schedule and design for installation of prompt notification system.
August 17, 1981	Letter from applicant forwarding responses to NRC requests for additional information. Responses will be incorporated into future FSAR amendment.
August 19, 1981	Letter from applicant forwarding responses to NRC requests for additional information. Responses will be incorporated into a future FSAR amendment.
August 20, 1981	Letter to applicant forwarding Hydrologic and Geotechnical Engineering Branch input regarding Class 9 accident liquid pathway consequences, in response to an NRC request.
August 21, 1981	Letter to applicant requesting additional information for Siting Analysis Branch OL safety review.
August 24, 1981	Letter to applicant identifying areas where additional information is required on preliminary evacuation time estimates for areas near the facilities.
August 25, 1981	Letter from applicant forwarding responses to NRC request for additional information. Ten oversize drawings enclosed. Responses will be incorporated into future FSAR amendment.
August 26, 1981	Letter to applicant requesting additional information and commitments required to prepare SER input on emergency planning and preparedness.

August 27, 1981	Letter from applicant forwarding responses to NRC request for additional information. One oversize drawing included. Responses will be incorporated into future FSAR amendment.
September 1, 1981	Letter from applicant responding to NRC request for additional information. Response to be incorporated into future FSAR amendment.
September 3, 1981	Letter to the applicant forwarding list of items that require additional information before SER issuance. Letter requests schedule for applicant responses.
September 3, 1981	Letter from applicant responding to NRC request for additional information on open items identified during Instrumentation and Control Systems Branch review of FSAR Chapter 7. Responses to be incorporated into future amendment.
September 3, 1981	Letter from applicant informing NRC that all generic letters have been reviewed and addressed in previous meetings or correspondence.
September 4, 1981	Letter from applicant forwarding revisions to specific FSAR question responses. Revisions will be incorporated into a future FSAR amendment.
September 8, 1981	Letter from applicant forwarding responses to NRC request for additional information on the physical security plan.
September 9, 1981	Letter to applicant forwarding request for additional information on FSAR QA section.
September 9, 1981	Letter from applicant forwarding responses to NRC request for additional information. Responses will be incorporated into a future FSAR amendment.
September 11, 1981	Letter from applicant reflecting commitment to comply with specific listed Regulatory Guides. Commitments will be reflected in FSAR revisions.
September 11, 1981	Letter from applicant forwarding additional information in response to an NRC request. Response will be incorporated into a future amendment.
September 11, 1981	Letter from applicant forwarding response to an NRC request for additional information on evacuation time estimates.
September 14, 1981	Letter from applicant forwarding response to NRC request for additional information for OL safety review.

September 14, 1981	Letter from applicant forwarding monthly status report of construction and startup progress for the month of August 1981.
September 15, 1981	Letter from applicant forwarding response to an NRC request for additional information on specific FSAR open items.
September 16, 1981	Letter from applicant forwarding responses to Materials Engineering Branch request for additional information on loose parts monitoring system and concrete expansion anchor design. Responses to be incorporated into FSAR amendment.
September 16, 1981	Letter from applicant forwarding FSAR Amendment 6.
September 16, 1981	Letter to applicant forwarding human factors engineering control design review and audit report.
September 18, 1981	Letter to applicant forwarding human factors engineering control room design review/audit report. Formal response requested.
September 21, 1981	Letter from applicant forwarding response to NRC request for additional information. Material will be incorporated into an FSAR amendment.
September 24, 1981	Letter from applicant forwarding responses to NRC request for additional information.
September 24, 1981	Letter from applicant forwarding Central Files version of St. Lucie County letter on acceptance of evacuation time estimates for emergency planning zone.
September 24, 1981	Letter from applicant forwarding letter of St. Lucie County acceptance of evacuation time estimates for the EPZ.
September 28, 1981	Letter from applicant notifying NRC of organizational changes in nuclear affairs, nuclear fuels and power resources departments.
September 29, 1981	Letter from applicant forwarding responses to NRC requests for additional information. Responses will be incorporated into a future FSAR amendment.
September 29, 1981	Generic letter 81-36 revising response schedule for NUREG-0737, Item II.D.1 (relief and safety valve testing).
September 30, 1981	Letter to applicant requesting that comparison of fire protection plan to 10 CFR 50, Appendix R, be included in overall fire protection program submittal.

October 2, 1981	Letter from applicant forwarding itemized review of compliance with significant rules and regulations.
October 6, 1981	Letter from applicant forwarding responses to fire protection questions, revisions to various 440 series questions, revisions to various 440 series questions, and revised FSAR Chapter 15, in response to NRC request for additional information. Responses will be incorporated into a future FSAR amendment.
October 7, 1981	Letter from applicant forwarding schedule for simulator and licensing exams for simulator and licensing exams for 1982 and January 1983 in response to NRC Generic Letter 81-29.
October 8, 1981	Letter from applicant forwarding modifications to a previous submittal of a conceptual design for an emergency operations facility.
October 9, 1981	Letter to applicant forwarding SER (NUREG-0843). Letter discusses Federal Register notice of availability.
October 12, 1981	Letter from applicant requesting confirmation of proposed modification to city water tanks to insure fire water availability.
October 14, 1981	Meeting with applicant to discuss procedures used for compaction to achieve slope stability around intake structures.
October 15, 1981	Meeting with applicant in Bethesda, MD to discuss surge test portion of matrix power supply test program.
October 15, 1981	Meeting with the applicant in Bethesda, MD to discuss seismic displacement of Category I supports.
October 15, 1981	Letter from applicant forwarding responses to requests for additional information.
October 16, 1981	Meeting with applicant to discuss applicant's analysis of a station blackout.
October 20, 1981	Letter from applicant forwarding monthly status report for construction and startup for September 1981.
October 22, 1981	Letter from applicant forwarding responses to CPB request for additional information on instrumentation to detect conditions of inadequate core cooling.
October 22, 1981	Letter from applicant forwarding FSAR Amendment 7.

October 27, 1981	Letter from applicant forwarding response to NRC request for additional information. Responses include slope compaction and SER open items on inadequate core cooling emergency procedures.
October 27, 198	Letter from applicant advising that a report has not been received from the pump vendor on a potential deficiency concerning linear indications in a reactor coolant pump volute.
October 27, 1981	Letter from applicant forwarding responses to previously submitted requests for additional information.
October 27, 1981	Letter from applicant forwarding responses to requests for additional information. Also forwards summary of October 23, 1981 meeting.
November 3, 1981	Letter to applicant confirming acceptance of criteria to ensure availability of water for dedicated standpipe for facility fire protection.
November 4, 1981	Letter from applicant forwarding proprietary and nonproprietary versions of "Preliminary Assessment of St. Lucie 2 Fuel Structural Integrity Under Faulted Conditions."
November 10, 1981	Generic Letter 81-38 to applicant providing guidance for the storage of low level radwastes at power reactor sites.
November 10, 1981	Letter from applicant forwarding responses to NRC requests for information on battery capacity and load shedding during station blackout.
November 17, 1981	Letter from applicant discussing equipment functional testing. The letter also discusses data which supports analytical chemistry procedures and post-accident sampling system.
November 18, 1981	Letter from applicant forwarding report number CEN-169(L)-P, "Test Report on Fluid Mixing in Scaled Reactor Vessel Flow Model."
November 19, 1981	Letter from applicant with notification that information requested in Generic Letter 81-21 on natural circulation cooldown was provided during OL review.
Novmber 19, 1981	Letter from applicant advising that a fully authorized and approved emergency operating procedure for station blackout will be provided by March 31, 1982.
November 19, 1981	Letter from applicant forwarding construction and startup progress report for October 1981. Revised report for September 1981 also included.

November 20, 1981	Letter to applicant forwarding summary of 259th ACRS meeting November 12-14, 1981 to review OL application.
November 23, 1981	Letter from applicant forwarding responses to requests for additional information on the turbine missile analysis.
November 24, 1981	Letter from applicant identifying commitment to insure that the plant staff can be augmented to levels specified in Table B-1, NUREG-0654, Rev. 1 within 45 to 75 minutes of notification.
November 30, 1981	Letter from applicant informing NRC that a response to specific ASB questions will be forwarded by December 18, 1981.
November 30, 1981	Generic Letter 81-39 to applicant forwarding Federal Register Notice of policy statement on low level radwaste volume reduction.
November 30, 1981	Letter from applicant forwarding information on safety-related electrical equipment.
December 1, 1981	Letter from applicant forwarding report of construction and startup progress for October 1981 and a revision of the September 1981 report. Supersedes similar letter dated November 19, 1981.
December 2, 1981	Letter from applicant forwarding preliminary report for the Seismic Qualification Review Team.
December 3, 1981	Letter from applicant forwarding instrumentation installation schedule for inadequate core cooling indication per NUREG-0737.
December 4, 1981	Letter from applicant forwarding comments on the Safety Evaluation Report, NUREG-0843.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, D. C. 20555

November 17, 1981

The Honorable Nunzio J. Palladino
Chairman
U. S. Nuclear Regulatory Commission
Washington, DC 20555

Subject: REPORT ON ST. LUCIE PLANT UNIT NO. 2

Dear Dr. Palladino:

During its 259th meeting, November 12-14, 1981, the Advisory Committee on Reactor Safeguards reviewed the application of the Florida Power and Light Company (the Applicant) for authorization to operate the St. Lucie Plant Unit No. 2. The project was considered at a Subcommittee meeting in West Palm Beach, Florida on October 30-31, 1981 and members of the Committee toured the facility on October 30, 1981. In its review the Committee had the benefit of discussions with representatives of the Applicant, Combustion Engineering, Inc., Ebasco Services, Inc., the NRC Staff, and members of the public. The Committee also had the benefit of the documents listed. The Committee commented on the construction permit application for St. Lucie Plant Unit No. 2 in a report dated December 12, 1974 to AEC Chairman Dixie Lee Ray.

St. Lucie Plant Unit No. 2 is located on Hutchinson Island adjacent to Unit No. 1, which went into commercial operation in December 1976. Both units use Combustion Engineering nuclear steam supply systems with a rated core power of 2560 MWt. The two units are nearly identical.

A number of items have been identified as Outstanding Issues, Confirmatory Issues, and License Conditions in the NRC Staff's Safety Evaluation Report dated October 1981. These include some TMI-2 Action Plan requirements. We believe these issues can be resolved in a manner satisfactory to the NRC Staff. We also recommend resolution of concerns on instrumentation for detection of inadequate core cooling expressed in the ACRS letter to the Executive Director for Operations dated June 9, 1981.

Discussion with the Florida Power and Light Company Staff indicated that emergency operating procedures for dealing with off-normal plant behavior that might develop during the operation of St. Lucie Plant Unit No. 2 are incomplete. We recommend that a concentrated effort be made by the Florida Power and Light Company staff to complete emergency operating procedures which take advantage of new information and approaches developed during the past two years. This matter should be resolved in a manner satisfactory to the NRC Staff. The Committee wishes to be kept informed.

At the time this site was initially approved, the population density was relatively low, and the projected increase during the life of the plant was not unusually large. Since that time, the growth in population has been much more rapid than predicted, and current estimates predict continued growth at relatively high rates. Although the present population and that predicted for the next several years are not a cause for concern, it now seems possible that the population density in portions of the surrounding area could reach a level, during the lifetime of the St. Lucie Plant, that might then warrant additional measures. We recommend that the Applicant and the NRC Staff periodically review the actual and projected population growth. If required as a result of these reviews, plans for appropriate preventive or remedial measures could then be made in a considered but timely manner.

We recommend that the Staff give due regard to the special nature of this site in evaluating the final emergency plan.

The Advisory Committee on Reactor Safeguards believes that, if due regard is given to the items mentioned above, and subject to satisfactory completion of construction, staffing, and preoperational testing, there is reasonable assurance that the St. Lucie Plant Unit No. 2 can be operated at core power levels up to 2560 MWt without undue risk to the health and safety of the public.

Additional comments by Members H. W. Lewis and M. S. Plesset are presented below.

Sincerely yours,

J. Carson Mark

J. Carson Mark
Chairman

Additional Comments by Members H. W. Lewis and M. S. Plesset

In the aftermath of the accident at Three Mile Island Unit 2, which dramatically emphasized the importance of instrumentation to follow the course of an accident, the NRC Staff has required applicants for an Operating License to demonstrate specific capability to detect the onset of inadequate core cooling. For PWRs this has come to mean in practice the provision, inter alia, of an instrument which can be called a water-level indicator for the pressure vessel. (Although the NRC Action Plan allows for alternatives, none appear to have been seriously contemplated.) A number of such devices have been accepted and/or proposed, some of which measure differential pressure, some average void fraction in a part of the pressure vessel, some cooling rate at a number of places in the vessel. All can give spurious response because of dynamic effects.

Many of these views have been previously expressed in the Committee letter of June 9, 1981.

We are concerned that, in the commendable eagerness to avoid a repetition of TMI, the NRC Staff is requiring ill-defined instrumentation without any clear picture of the contribution of that instrumentation to the prevention or mitigation of accidents - considerations which must necessarily be scenario dependent. If it were really true that core water level were the important parameter, then differential pressure indicators would appear to be preferable, provided the coolant is quiescent. If instead cooling capacity is important, then some form of heated wire or thermocouple would appear to be preferable. Since either may be acceptable, we are left with the inference that the NRC Staff has not really clarified the role of this instrumentation.

We believe that, before, not after requiring these instruments for all the new plants, the NRC Staff should develop a position regarding their utility. This position, which should be based upon accident analysis and risk assessment, would lead to a much clearer understanding of just what instrumentation, if any, is needed.

REFERENCES:
1. Florida Power and Light Company, "St. Lucie Plant, Unit No. 2 Final Safety Analysis Report," with Amendments 1 through 6.
2. U.S. Nuclear Regulatory Commission, "Safety Evaluation Report Related to the Operation of St. Lucie Plant, Unit No. 2," Docket No. 50-389, USNRC Report NUREG-0843, dated October 1981.
3. Letter from Betty Lou Wells to the Chairman of the Advisory Committee on Reactor Safeguards, dated October 28, 1981.
4. Written statement by Joette Lorian, Research Director for the Center for Nuclear Responsibility.

APPENDIX C

CONTROL ROOM DESIGN REVIEW (I.D.1)

HFEB SAFETY EVALUATION REPORT ON THE ST. LUCIE NUCLEAR STATION UNIT 2

INTRODUCTION

The Control Room Design Review/Audit (CRDR/A) conducted by the HFEB included an evaluation of the control room layout, the adequacy of the information provided, the arrangement and identification of important controls and instrumentation displays, the usefulness of the audio and visual alarm systems, the information recording and recall capability, lighting, and other considerations of human factors that have an effect on operator performance. The review was performed by means of an inspection of the control panels, interviews with operators, and observation of operators as they walked through selected emergency procedures. Evaluation was performed using NUREG-0700 ("Guidelines for Control Room Design Reviews").

DISCUSSION

Although our review identified human engineering discrepancies, we found that overall the control room was designed to permit effective and efficient operator actions.

Systems and items which were not available for review at the time of our site visit are: (1) the control room environment and the environment in the area of the remote shutdown panels, (2) the general layout of the control room, (3) the operator consoles (cardboard mock-ups), (4) the communications equipment, (5) the storage and availability of emergency equipment for use by operating personnel, (6) the final installation of controls and displays, (7) the auditory signal system, and (8) the plant process computer. We require that the applicant perform an evaluation of these items after installation and submit their findings, proposed corrective actions, and schedule for implementing the actions. We must receive this information for our review and approval 60 days prior to issuance of the operating license.

HUMAN ENGINEERING DISCREPANCIES (HED) IDENTIFIED

The review team identified HEDs which were documented in a CRDR/A report that was transmitted to the applicant. The report sets priorities for correcting the discrepancies according to their importance. HEDs were given a priority rating of one, two, or three (high, moderate, low), based on the increased potential for operator error and the possible consequences of that error. Some discrepancies that were judged to be of Priority 3, but which had resolutions which involved simple corrective actions relative to the potential for improving operator performance, were given a Priority 3^1. This priority rating indicates that the discrepancy should be corrected prior to fuel loading.

Discrepancies identified as Priority 1, 2, and 3[1] are required to be corrected before issuance of an operating license. These discrepancies are listed in Part A of this Appendix along with descriptions of the applicant's commitments to correct them. We judge that, if all discrepancies are corrected in accordance with the applicant's commitments, the enhanced detection and response capabilities of the operator and the reduced probability of operator error under stressful conditions will allow safe operation of St. Lucie Unit 2.

Priority 3 items were individually identified in the CRDR/A report, dated September 10, 1981, and are not included in this appendix. Since that time, the priority rating of some discrepancies was changed from a higher rating to a 3. Those changes are listed in Part B of this appendix. We require the applicant to report on all Priority 3 discrepancies as part of their future DCRDR and to determine the best and most feasible solutions at that time. No immediate action is specified for correction of Priority 3 deficiencies because we believe that they will not significantly affect safe operation of the plant.

Some discrepancies identified in our CRDR/A report were subsequently determined to be invalid. Descriptions of those discrepancies and the rationale for their deletion are presented in Part C of this appendix.

HUMAN ENGINEERING DISCREPANCIES TO BE CORRECTED PRIOR TO ISSUANCE OF AN OPERATING LICENSE

This section contains a description of those discrepancies which must be corrected prior to issuance of an operating license. Following each discrepancy is a statement of the Florida Power and Light Company's (FPL) commitment for corrective action.

A.1.0 CONTROL ROOM WORKSPACE

FINDING

A.1.1 There are two large floor obstructions in the form of thick plywood sheets attached to the floor. One is between the control console mockups and one is near the restroom location. (1.2)*

RESPONSE

The plywood sheets referenced in the above finding are presently covering two blockouts which will be used as control cable routine paths. The blockout located between the control console mockups will be covered by the operator's work desk and will not provide a traffic interference problem. The second blockout located near the restroom was provided for the positioning of the auxiliary control panel and will not provide any traffic flow restrictions. Presently a review is being conducted for relocating the auxiliary control panel. If the panel is relocated, then the subject blockout will be filled thus eliminating the tripping hazard.

FINDING

A.1.2 The temporary phone attached to Panel 202 has a long cord which presents a tripping hazard in an operator pathway. It was noticed that phone cords in Unit 1 presented a similar tripping hazard. (1.3)

RESPONSE

The temporary phones will be removed and the permanent communication system will be installed prior to issuance of an operating license thus eliminating the subject tripping hazard.

FINDING

A.1.3 There are no provisions for key storage and no procedures for key access control for keys used in the Control Room and for keys used at the Remote Shutdown Panel. (1.6)

*Throughout the report the use of parentheses, such as (1.4), refers to the section and finding number used in the HFEB Control Room Design Review/Audit report, dated September 10, 1981.

RESPONSE

Key storage will be provided as well as the necessary key access control procedures for those keys used in the Control Room and Remote Shutdown Panel prior to fuel load. The Remote Shutdown Panel SIS block keys will be maintained at RAB control access point.

FINDING

A.1.4 All of the panels had controls which were less than 3 inches from the front edge of the benchboard. The benchboard hardrails had not been installed at Unit 2 at the time of the review. It was noted that the Unit 1 benchboard rails obscure the view of many controls and displays from the operator console. (1.10)

RESPONSE

The St. Lucie Unit No. 2 handrails will be installed at a lower position on the subject benchboards so as to not obscure the view of those controls and displays, which are located on the front edge of the benchboards, from the operator console. The handrails will be installed prior to issuance of an operating license.

FINDING

A.1.5 The normal lighting level in the backpanel areas was inadequate. The level at Backpanel 206 was 5.5 ft-candles, which is even less than the minimum requirement of 10 ft-candles for a passageway. (1.12)

RESPONSE

Incident light levels will be reviewed and brought up to acceptable levels as outlined in NUREG-0700. This item will be scheduled for implementation prior to issuance of an operating license.

FINDING

A.1.6 Glare was a problem throughout the control room. At the time of the review, no diffusing grid had been placed over the fluorescent lighting as has been done in Unit 1. The glare in Unit 2 had a varying impact from one instrument to the next, with the worst case being nearly total obscuration of displayed informaton. (1.13)

RESPONSE

A re-evaluation of the glare problem will be performed after the diffusing grid has been installed. Those items then still found to have glare problems will have suitable backfits implemented prior to issuance of an operating license.

FINDING

A.1.7 There is no direct means of testing the operability of control room emergency lighting. (1.14)

RESPONSE

There will be a direct means of testing the operability of the control room emergency lighting system prior to issuance of an operating license.

FINDING

A.1.8 The emergency lighting illumination levels were too low for accurate reading of panel displays and labels. Readings varied from 22.6 to 1.9 ft-candles. The Panel 204 reading was 8.3 ft-candles. (1.15)

RESPONSE

Lighting diffusers were not installed at the time of the audit. Upon installation, incident light readings will be taken. Based on data from the above, additional lights, as required, will be installed to bring emergency control room illumination to acceptable levels as outlined in NUREG-0700. This item will be scheduled for implementation prior to issuance of an operating license.

FINDING

A.1.9 The two separate Control Transfer Panels for the Remote Shutdown Panel are not provided with security devices to prevent unauthorized transfer of control between the Control Room and the Remote Shutdown Panel. (1.16)

RESPONSE

The Remote Control Transfer Panels will have a security seal for security purposes. Operations of any control transfer switch is annunciated in the control room. These provisions will be implemented prior to issuance of an operating license.

A.2.0 COMMUNICATIONS

FINDING

A.2.1 The communications equipment and procedures for Unit 2 were not completed and could not be evaluated. (2.1)

RESPONSE

The SL-2 communications system is currently under design. The system will be reviewed in accordance with the communications section of NUREG-0700. This item is scheduled to be implemented prior to issuance of an operating license.

A.3.0 ANNUNCIATORS

FINDING

A.3.1 The function of the annunciator tile labeled ANNUNCIATOR POWER SUPPLY on annunciator Panel K is not clear. (3.1)

RESPONSE

The tile will be re-engraved to read "Annunciator Backup Power Supply" prior to the issuance of an operating license.

FINDING

A.3.2 There are no annunciators for the HYDRAZINE system. (3.2)

RESPONSE

Results of an engineering review of the system have identified any/all required annunciators for the Hydrazine system. These will be added to the annunciator system prior to issuance of an operatng license.

FINDING

A.3.3 Some annunciator tiles with multiple inputs do not have reflash capability. (3.4)

RESPONSE

Multiple input annunciator windows will undergo assessment as to reflash capability. Any that do not "reflash" and require the function will be provided with the "reflash" and "reaudible" function. This item will be reviewed and implemented prior to issuance of an operating license.

FINDING

A.3.5 The annunciator audible alarms are only marginally louder than the ambient noise in the control room. (3.8)

RESPONSE

The volume, frequency, and modulation of annunciator audible are adjustible. Audible signal characteristics will be manipulated to conform to the NUREG-0700 guidelines prior to issuance of an operating license.

FINDING

A.3.6 The annunciator audible alarm devices for Panels 201, 203, and 205 are located behind the panels, making it difficult for operators to localize the source of an alarm. (3.9)

RESPONSE

The sound sources will be mounted such that signals will propagate directly into the control area without having to pass through the control room boards. This item will be implemented prior to issuance of an operating license.

FINDING

A.3.7 The annunciator illumination system does not ensure that an indication of alarmed conditions will be provided to the operator if failure of an annunciator light flasher occurs. In case of flasher failure of an alarmed tile, the tile light should illuminate and burn steadily. (3.10)

RESPONSE

Each annunciator panel has a test function which illuminates every window and verifies the flasher function. Any dark window indicates bulb or annunciator failure. Any annunciator that does not flash has a failed flasher. The test will be performed once a shift.

FINDING

A.3.8 None of the annunciator panels in the control room have labeling of their vertical or horizontal axes to aid in matrix location and identification of individual tiles. (3.12)

RESPONSE

Matrix type location cues will be added to the annunciator panels and annunciator response procedures. This item will be implemented prior to fuel load.

FINDING

A.3.9 Blank annunciator tiles on almost all annunciator panels are illuminated during normal operation. (3.13)

RESPONSE

Blank annunciator tiles will be extinguished. This will be accomplished prior to fuel load.

FINDING

A.3.10 Many annunciator tile legends are wordy. Some tiles have as many as 14 words. (3.14)

RESPONSE

Annunciator verbiage is being reviewed and will be limited in content in accordance with NUREG-0700.

Annunciator tiles are to be re-engraved, using standardized abbreviations and syntax, limiting number of words/abbreviations per tile. This item is scheduled for implementation prior to issuance of an operating license.

FINDING

A.3.11 Annunciator font size (0.2 inches in height) is too small for reliable reading from the operator annunciator control positions. (3.15)

RESPONSE

Annunciator tiles are to be re-engraved, using larger, more readable font. This item is scheduled for implementation prior to issuance of an operating license.

FINDING

A.3.12 The space between legend lines on annunciator tiles is less than 1/2 the character height. (3.17)

RESPONSE

The space between legend lines on the annunciator tiles will comply with NUREG-0700. This item will be implemented prior to issuance of an operating license.

FINDING

A.3.13 One annunciator board on the Line Repeat Panel has two redundant sets of controls located within 12 inches of each other. (3.18)

RESPONSE

One set of annunciator controls will be removed prior to fuel load.

FINDING

A.3.14 There are no separate silencing controls on any annunciator control systems. (3.19)

Florida Power and Light intends to install a three second automatic annunciator master silencer on Unit No. 2 prior to issuance of an operator license. The three-second master silencer would automatically silence the incoming audible alarm after three seconds giving the operator sufficient time to glance at the incoming alarm to determine its significance; however, still allowing him freedom to continue the task at hand until such time as he could reset the subject alarm. After the audible signal is silenced it would be reactivated and the process repeated for an incoming alarm.

FINDING

A.3.15 The relative location of annunciator control button groups is not the same from panel to panel and the annunciator control buttons are not arranged in the same order in the control group at each panel. (3.20)

RESPONSE

The annunciator control button will be located such that they are in the same configuration in the control group as each panel and where possible they will be placed in the same general locale on the subject panels. In addition, these controls will be demarcated to assist in distinguishing them from other control push buttons. This backfit will be implemented prior to issuance of an operating license.

FINDING

A.3.16 Annunciator Panel N contains a tile with a temporary label. The WASTE MANAGEMENT LOCAL ALARM GROUND DETECTED POWER FAILURE tile label is handwritten on the face of the tile. (3.21)

RESPONSE

The subject tile will be engraved in accordance with the annunciator tile lettering specification to be issued as part of the annunciator labeling review which is scheduled for engineering completion prior to fuel loading.

A.4.0 CONTROLS

FINDING

A.4.1 Some controls needed to perform system operating tasks are not in the control room. (4.1)

Examples:

a) Auxiliary Feedwater Pump Start Bypass control
b) Condensate Pump 2C control

RESPONSE

a) Auto-start of the Auxiliary Feedwater System has not been installed. The future design will include the start bypass control and will be implemented prior to issuance of an operating license.

b) Condensate pump 2C is a spare pump used when pumps 2A or 2B are out of service for maintenance. 2C pump is manually aligned to either the 2A or 2B 4160 bus, depending on which pump it is replacing. The control switch for that associated pump then becomes the control switch for 2C pump. No further action is required on this item.

FINDING

A.4.2 Some process controllers on Panels 205 and 206 have inoperative OPEN/CLOSE pushbuttons that are disconnected and have no control function. (4.3)

Examples:

a) HIC-3618
b) HIC-3628
c) HIC-3638
d) HIC-3648
e) SI Loop 2A2 Check Valve Leakage

RESPONSE

The non-functional control buttons will be removed and the holes blanked. This item will be completed prior to issuance of an operating license.

FINDING

A.4.3 The Turbine Trip pushbutton is not protected to prevent unintentional operation. (4.4)

RESPONSE

An elevated switchguard will be provided on this switch. This will be implemented prior to fuel load.

FINDING

A.4.4 The SI Loop Check Valve Leakage HIC-3638 process controller operates in reverse of the conventional operation of other process controllers in the control room. (4.5)

RESPONSE

These control buttons are not functional and will be removed and the holes covered prior to issuance of an operating license.

FINDING

A.4.5 Some rotary switches do not conform to the OPEN-Right (Clockwise)/ CLOSE-Left (Counterclockwise) convention for switch positions. (4.6)

Examples:

a) Generator No. 2 switch on Line Repeat Panel has OPEN-Left/CLOSE-Right positions.

b) Turbine Drain Valve controls on Panel 201 have OPEN-Left/AUTO-Center/CLOSE-Right positions.

c) Loop 2A2 and Loop 2B1 Charging Line Valve controls have RESET-Left/CLOSE-Middle/OPEN-Right positions.

RESPONSE

Present Florida Power and Light convention is: (1) Valve control switches operate such that open is to the right and closed is to the left with red lights indicating flow/opened and green lights indicating no flow/closed. (2) Breaker control switches to operate such that closed is to the right and open/trip is to the left with red lights indicating energized/closed and green lgihts indicating de-energized/open.

In addition, the convention is to have the green indicating lights on the left of the control switch and the red indicating lights on the right. Shape coding of breaker control handles, i.e., thumb switches will be used to reduce operator confusion. The control board is scheduled to be reviewed for consistency of convention application with discrepancies resolved prior to issuance of an operating license.

The turbine drain valve control on panel 201 will be corrected to conform to the above mentioned convention prior to issuance of an operating license.

FINDING

A.4.6 Some keyswitches have a black ring that might be interpreted as a color code while other keyswitches do not. There is no apparent significance of this difference. (4.7)

RESPONSE

The black ring indicates that the valve is "Locked Open." Absence of the black ring means the valve is "Locked Closed." One valve does not conform to this, and will be changed prior to fuel loading.

FINDING

A.4.7 The backlit legend pushbuttons and the backlit legend indicator lights in several arrays on Panels 201 and 202 are identical in appearance, size, and shape. Control/display substitution errors are possible. (4.9)

Examples:

a) DEH Valve Test panel
b) Generator Megavar displays
c) Diesel Generator controls and displays

RESPONSE

This finding will be addressed and resolved through control and display labeling and coding. Implemention will be complete prior to issuance of an operating license.

FINDING

A.4.8 Covers on backlit legend pushbuttons and indicators are interchangeable and are not coded to identify their correct location in the control/display arrays. (4.10)

RESPONSE

Identifying markings will be placed on the removable portion of the units and the housing, thereby identifying the appropriate positions of removable control or display units. This item will be implemented prior to issuance of an operating license.

FINDING

A.4.9 Some keyswitches do not conform to the keyswitch orientation convention used in the control room. (4.11)

Examples:

a) Minimum Flow Header A Isolation Valve V-3496 switch on Panel 206.

b) DEH Turbine Control OPC switch on Panel 201.

RESPONSE

Keyswitch positions will be oriented to be consistent with Control Room conventions (key teeth down) and backfits implemented prior to fuel loading.

FINDING

A.4.10 Rotary switches and keyswitches have unlabelled positions. (4.12)

Examples:

a) SIAS Block Channel SA and SB keyswitches on Panel 206
b) MSIS Block Channel SA and SB keyswitches on Panel 206
c) Trip Circuit Reset rotary switches on the RPS Panel

RESPONSE

These positions will be labeled prior to issuance of an operating license.

FINDING

A.4.11 Rotary selector switches on Panel 201 have pointers engraved in the switch handle that are not marked with a contrasting color to make them readable. (4.16)

Examples:

a) Exciter Supply Breaker
b) Generator Ground Detector
c) Voltage Adjuster
d) Base Adjuster

RESPONSE

The switch handles will be provided with high contrast pointers. This item will be implemented prior to fuel loading.

A.5.0 DISPLAYS

FINDING

A.5.1 Assuming its label is correct, the AUX FEEDWATER HDR C FLOW/PRESSURE indicator FI-09-2C/PI-09-8C on Panel 202 should display values of two different variables. The installed meter can display only one variable. (5.1)

RESPONSE

The correct meter will be capable of displaying both variables. The proper indicator will be installed prior to fuel loading.

FINDING

A.5.2 There is no distinction between the three backlit indicators labeled HI POWER TRIP on the RPS Matrix Test Panel nor between the two indicators labeled HI RATE. (5.2)

RESPONSE

The above components will be appropriately labeled. This item will be implemented prior to issuance of an operating license.

FINDING

A.5.3 The data channel identification labels for HVAC Panel trend recorders PR-25-1A, PR-25-1B, and PR-25-2 do not indicate which recorder scale to use with each variable displayed on the multi-range, multi-channel recorders. (5.3)

RESPONSE

The scales for the above will be appropriately labeled and identified. This item will be implemented prior to issuance of an operating license.

FINDING

A.5.4 On Panel 201, the GENERATOR EXCITER FIELD DC VOLTS meter scales are not marked to indicate positive and negative values. (5.4)

RESPONSE

The display will be appropriately labeled "Voltage Regulator Null Meter." This will be accomplished prior to fuel loading.

FINDING

A.5.5 On Panel 201, the VIBRATION PHASE ANGLE METER VBI-22-1 and the ECCENTRICITY PHASE ANGLE METER ECC-22-1 do not have indications of positive or negative above and below zero. Also, their scales are graduated in 10's above zero and in 30's below zero. (5.5)

RESPONSE

The extreme values for these displays will be appropriately labeled. These are standard meters throughout all Florida Power and Light power plants and to change them could have a negative effect. This labeling effort will be completed prior to fuel loading.

FINDING

A.5.6 The LED displays generally have poor readability due to glare, scratchable face plate surfaces, and poor contrast. (5.8)

Example:

a) LINE REPEAT PANEL
b) PANEL 203
c) MEGAVAR PANEL
d) PRESSURIZER PRESSURE

RESPONSE

Glare and potential face plate scratching will be addressed through display shielding to reduce incident light to the display surface and protect face plates.

Display contrast will be further evaluated and reported on within the reporting requirements of NUREG-0700.

FINDING

A.5.7 Several meters, primarily G.E. circular meters, have confusing scale markings. The scale spacing is non-linear and there are no graduations near the zero marking on the meter scale. Also, it is not clear what downscale meter pointer position indicates a meter failed condition. (5.10)

Example:

a) GENERATOR AMPERES AM-8810B and AM-8810C on Panel 201
b) GENERATOR KILOVOLTS VM-881

RESPONSE

These meters are not operated at the lower ranges. The scales are such that accuracy and readability are of high quality in the normal operating range. Downscale meter position will be reviewed as part of the long-term design review. Normal operating ranges will be marked on the meter face.

FINDING

A.5.8 Several meter scales have thick black marks to extend major tick marks to the scale numerals. These marks give the misleading appearance of minus (-) signs in front of the meter scale numerals. (5.11)

Examples: (HVAC Panel)

a) PDIS-25-1B
b) PDI-25-15B

RESPONSE

The marks viewed as being interpreted as minus (-) signs will be removed. This will be accomplished prior to fuel loading.

FINDING

A.5.9 There are several displays which use unconventional scale graduations. (5.12)

Examples:

a) Panel 201: DIESEL GENERATOR 2B MVARS VARM-1616
b) Panel 204: WIDE RANGE % POWER JI-001B
c) Panel 203: LOOP 2A COLD LEG TEMP TIC-111
d) Diesel Gen 2B Frequency

RESPONSE

The displays listed in the finding will be modified as follows:

Meter faces will be color coded to reflect normal operating ranges prior to issuance of an operating license. Displays will be reviewed for scale convention during the long-term control room review and reported on in accordance with NUREG-0700.

FINDING

A.5.10 Green FPL tape (denoting equipment turnover to FPL) and meter calibration certification stickers obstruct labels and meter scales in several places and generally clutter the appearance of the boards. (5.13)

RESPONSE

The above clutter will be removed prior to plant low power operation and after system turnovers have been completed.

FINDING

A.5.11 On the Line Repeat Panel there is either a reversal of Green-Left/Red-Right convention of indicator light positions or the colored lamps are incorrectly installed. (5.15)

RESPONSE

The lamps have been reversed to conform to the predominant control room convention.

FINDING

A.5.12 There is a widespread use of amber and blue colors for electrical system status lights while a red/green/amber convention is used on most other systems in the control room. (5.16)

RESPONSE

A lighting color convention will be established with implementation prior to issuance of an operating license.

FINDING

A.5.13 The CONTAINMENT H2 PURGE CONTROL VALVE FCV-25-8 on the HVAC Panel violates the conventional color coding of indicator lights by using green to indicate OPEN and red to indicate CLOSED. (5.17)

RESPONSE

The lights have been changed to conform to the control room color convention.

FINDING

A.5.14 On Panel 203, the PRESSURIZER PRESSURE METERS PIC-1105 and PIC-1106 indicate an increase in pressure by a downward movement of the pointer. (5.18)

RESPONSE

The meters will be rotated and new scales installed such that they indicate an increase in pressure by an upward movement of the pointer. This item will be implemented prior to issuance of an operating license.

FINDING

A.5.15 On process controller vertical scales, circular meters, and large horizontal trend recorders, the pointers obscure scale numerals. (5.19)

Example:

a) GENERATOR TEMPERATURE TR-22-30

RESPONSE

Normal operating bands will be marked on meters prior to issuance of an operating license. The obscuration of numerals will be reviewed as part of the long-term evaluation in accordance with NUREG-0700.

FINDING

A.5.16 The CONDENSATE & STM GEN BLOWDOWN CONDUCT CR-05-1 trend recorder does not have a legend to distinguish between pen colors. (5.20)

RESPONSE

An appropriate label will be provided which clearly identifies pen colors and their meanings. This will be implemented prior to fuel load.

FINDING

A.5.17 The 0-5 psi operating band on the CONTAINMENT PRESSURE PIS-07-2B display on Panel 206 is very small compared to the full range of the display scale (0-100 psi). (5.21)

RESPONSE

The correct instrument is scaled 0-15 psi. This instrument is correct for its intended use during accident conditions and will be installed prior to issuance of an operating license.

FINDING

A.5.18 Throughout the control room, there is a lack of demarcation of the "normal", "safe", "caution", and "danger" ranges on display instruments. (5.22)

RESPONSE

This item will be addressed as part of the ongoing labeling and demarcation program which is scheduled to be implemented prior to issuance of an operating license.

FINDING

A.5.19 The Reactor Protection System Trip Status Panel has indicator lights which indicate OPEN on the bottom or left and CLOSED on the top or right. Both of these indicator light positions are opposite of normal convention. (5.23)

RESPONSE

The position of these lights will be corrected to conform to the established Control Room convention prior to issuance of an operating license.

FINDING

A.5.20 There are no lamp tests in the control room other than those for the annunciators. (5.24)

RESPONSE

A method will be developed to verify operability of the indicating lamps in the Control Room prior to fuel loading.

The following methods will be utilized for the verification:

a) direct indication by lamp test circuit, e.g., annunciator test

b) installing a filament warming circuit to extend the filament life

c) verification via redundant intelligence available on the board

d) evaluation of manufacturer's filament life rating to determine changeout requirements

e) the safety-related MOV position indication and breaker indication for safety-related pumps will be periodically tested as part of the pump and valve test program

f) nonsafety-related MOV and breaker indications will be tested as part of the monthly equipment rotation program.

FINDING

A.5.21 On Panel 201, the BATTERY 2A and BATTERY 2B status lights are single blue lights. There is no indication whether the light indicates normal or abnormal state when lit. (5.25)

RESPONSE

The above light's labels will be more clearly defined and will conform to established color code convention. This will be accomplished prior to fuel loading.

FINDING

A.5.22 On the HVAC Panel, each of the following systems has three associated indicator lights, two of which are red: (5.26)

CONTAINMENT FAN COOLERS:
2HVS-1A, 1B, 1C, 1D

RESPONSE

The red lights indicate speed. Center is the slow speed; the right red light is the fast speed. These lights will be appropriately labeled. This backfit will be implemented prior to issuance of an operating license.

FINDING

A.5.23 Several recorders are supplied with paper which is scaled differently than the scale on the recorder face. For example, the BORON CONCENTRATION RECORDER AP-2203 on PANEL 205, if installed as planned, will have four selectable ranges but will have only a single full range paper (0-2000). Thus, if the operator selects (0-500) range, a reading of 250 will be recorded as 1000, etc. (5.27)

Other examples:

a) Panel 201: GENERATOR FREQUENCY RECORDER F-REC-881
b) Panel 202: FEEDWATER AND STEAM GENERATOR BLOWDOWN PHR-05-1.

RESPONSE

a) Will have proper scales prior to operating license.
b) Will have proper scales prior to operating license.

Boron concentration changes gradually over core life. There would be no sudden transients requiring the use of multiple scales during normal operation. This recorder will use lined unscaled paper. The shift operator is aware of his boron concentration and relies on periodic chemistry readings for verification.

FINDING

A.5.24 The trend recorders on the HVAC Panel have data legend labels on the glass window which obscure the graph paper. The operator must open the recorder in order to read information. (5.28)

RESPONSE

Labels will be repositioned so that displayed information is unobscured. This will be implemented prior to fuel loading.

FINDING

A.5.25 A (0-125) nonlinear scale is used on the REACTOR MAKEUP WATER FLOW FRC-2210X display where a linear scale would do just as well. (5.30)

RESPONSE

Florida Power and Light agrees with priority assignment of this item. Due to the unique design of the instrument and long lead time for procurement, replacement may be after fuel load but will be implemented at the first opportunity after delivery but no later than first refueling. Emphasis during training and temporary labeling will be used as an interim measure.

FINDING

A.5.26 Several displays have no labeling to indicate what units their scales are measured in. (5.31)

Examples:

a) Panel 205: WASTE GAS FLOW RECORDER-FR-6648
b) Panel 203: PRESSURIZER SPRAY-HIC-1100
c) Panel 206: REFUELING WATER TANK LEVEL-LR-07-20

RESPONSE

Appropriate labels will be installed prior to issuance of an operating license.

FINDING

A.5.27 The % POWER METER on the Reactor Protection System Panel has a broken glass face. (5.32)

RESPONSE

The glass will be replaced prior to fuel loading.

A.6.0 LABELS AND LOCATION AIDS

FINDING

A.6.1 A number of controls and displays on Panel 203 have labels which are either missing or appear to be incorrect. (6.1)

RESPONSE

All labels will be reviewed as part of the labeling study. Those missing labels will be installed and those incorrect labels will be corrected. This discrepancy will be corrected prior to issuance of an operating license.

FINDING

A.6.2 Many trend recorders on Panel 205 and the HVAC Panel have blank labels or labels which do not identify the display's function. (6.2)

RESPONSE

This item will be reviewed during the labeling study and blank labels and/or nondescriptive labels will be corrected prior to issuance of an operating license.

FINDING

A.6.3 There are missing labels on the Plant Auxiliary Panel for switches and for switch position indicators. (6.4)

RESPONSE

Those missing labels on the Plant Auxiliary Panel will be installed prior to fuel loading.

FINDING

A.6.4 Some of the Auxiliary Feedwater Pump and Valve controls have unlabeled "Auto" positions. (6.5)

Example:

a) AUX FW PUMP/2A DISCH to SG2A VALVE

RESPONSE

Those pump and valve controls with unlabeled "Auto" positions will have these positions properly labeled prior to issuance of an operating license. This item will be included as part of the ongoing labeling study.

FINDING

A.6.5 On Panel 201 the BATTERY VOLTS 2A meter VM-1000 is incorrectly labeled as BATTERY VOLTS 2B. (6.7)

RESPONSE

Volt meter VM-1000 will have its label corrected prior to issuance of an operating license.

FINDING

A.6.6 The LOOSE PARTS MONITOR CABINET contains switches whose control functions and positions are not labeled. (6.8)

RESPONSE

Correct labels will be provided prior to fuel loading.

FINDING

A.6.7 Several toggle switches on the Reactor Regulating System Panel and on the Reactor Coolant Pump Vibration Monitor Panel have unlabeled switch positions. (6.9)

RESPONSE

Appropriate labels will be provided prior to fuel loading.

FINDING

A.6.8 On Panel 206, the key switch positions on the MSIS block switch are not labeled. (6.10)

RESPONSE

The MSIS block key switches will have their positions marked and properly labeled prior to issuance of an operating license.

FINDING

A.6.9 LPSI LOOP 2A FLOW METER on Panel 206 is mislabeled. It should read 2A1. (6.11)

RESPONSE

LPSI LOOP 2A FLOW METER on Panel 206 will have its label corrected as part of the labeling program review. This item will be corrected prior to issuance of an operating license.

FINDING

A.6.10 The LPSI HEADER PRESSURE METERS 2A and 2B on Panel 206 are either mislabeled or in the wrong panel locations. (6.12)

RESPONSE

These recorders/indicators are required to be powered from two independent safety grade power sources. To comply with the additional requirements of R.G. 1.75 these displays were located in the associated electrical train to achieve the required separation. As an interim measure prior to issuance of an operating license, demarcation will be used to make these items stand out. The detailed control room review will include evaluation of relocating the recorders.

FINDING

A.6.11 The CONDENSER VACUUM DISPLAY (PI-10-7B) on Panel 201 has a mislabeled scale. It should read "Inches Hg Vacuum" instead of "Inches Hg ABS". (6.13)

RESPONSE

The condenser vacuum display will be labeled as "inches HG" prior to fuel loading.

FINDING

A.6.12 The FEEDWATER PUMP 2A FLOW label on Panel 202 is incorrect. It should read FEEDWATER PUMP 2B FLOW. (6.15)

RESPONSE

The indicator will be appropriately labeled prior to fuel loading.

FINDING

A.6.13 The functional difference between the dual Steam Generator meters on the four ENGINEERING SAFEGUARDS LOGIC CABINETS is not labeled. (6.16)

RESPONSE

Appropriate labels will be provided prior to issuance of an operating license.

FINDING

A.6.14 There is no hierarchical arrangement of labels by system and subsystem throughout the control room. (6.17)

RESPONSE

A labeling and demarcation effort is underway. Hierarchical labeling and demarcation will be provided. This program is scheduled for completion prior to issuance of an operating license.

FINDING

A.6.15 On Panel 201, component identification labels are not consistently larger than component status (e.g., "start", "stop", "auto") labels. (6.18)

RESPONSE

Component identifying labels will be provided which are larger than component status labels. This will be done prior to fuel loading.

FINDING

A.6.16 Label placement convention is inconsistent throughout the control room. (6.19)

RESPONSE

Label placement is under review. However, as part of labeling effort, label visibility will take precedence over location consistency (except where substitution errors are likely due to inconsistent label locations). This item will be completed prior to issuance of an operating license.

FINDING

A.6.17 Labels on Panel 201 have been placed under displays and are often obscured by the overhanging bezel of the display they are intended to identify. (6.20)

RESPONSE

During relabeling, labels will be placed in nonobscured locations prior to issuance of an operating license.

FINDING

A.6.18 The label for the backpanel that contains the L & N PROCESS AND COOLING WATER TEMP. SELECTOR is below the switch array and is obscured. (6.21)

RESPONSE

The label will be relocated to a more visible position. This item will be completed prior to fuel loading.

FINDING

A.6.19 The WASTE GAS FLOW trend recorder on Panel 205 has no label to indicate what parameter is being monitored. (6.22)

RESPONSE

The parameters on all recorders will be appropriately labeled prior to issuance of an operating license.

FINDING

A.6.20 On Panel 202, the labeling for the light pairs representing the UHS CANAL BARRIER VALVES (I-S3-21-13, 14) is ambiguous. There is one label for two light pairs.

RESPONSE

The labeling will be changed to reflect the labeling of the two individual valves I-S3-21 and I-S3-21-14, respectively. This item will be completed prior to fuel loading.

FINDING

A.6.21 On Panel 201, labels for rotary switch control positions are not oriented horizontally and switch position labels are obscured by the control handle. (6.24)

Example:

a) AMMETER CONTROLS FOR BUS 2A1.

RESPONSE

The control handle will be modified or changed so that switch position labels are not obscured. Switch position label orientation will be further evaluated per the requirements of NUREG-0700. This item will be completed prior to fuel loading.

FINDING

A.6.22 On Panel 205, there is no indication on two-color trend recorders as to which color represents an actual reading and which represents the set point. (6.25)

RESPONSE

Labels will be provided that identify the pen color meanings. This item will be implemented prior to issuance of an operating license.

FINDING

A.6.23 The REACTOR CHANNEL TRIP BUTTONS on Panel 204 are not labeled as to function. The buttons should be labeled "TRIP". (6.26)

RESPONSE

The content of these labels will be reviewed and improved labels provided. This item will be implemented prior to issuance of an operating license.

FINDING

A.6.24 Most of the component labels on the FEEDWATER REGULATING RACK do not contain component identification numbers. (6.27)

RESPONSE

Permanent labels will be provided prior to fuel loading.

FINDING

A.6.25 Labels on Panels 205 and 206 are very similar and can be confusing. (6.28)

Examples:

a) BORIC ACID GRAVITY FEED VALVE V-2508 and
BORIC ACID GRAVITY FEED VALVE V-2509

b) HPSI TO HOT LEG 2B VALVE V-3551 and
HPSI TO HOT LEG 2B VALVE V-3523

RESPONSE

Similar labels will be resolved as part of the relabeling effort. This item will be implemented prior to fuel loading.

FINDING

A.6.26 On Panel 206, there is an error on the HPSI HDR B TO LOOP 2B2 label. It should read LPSI instead of HPSI. (6.29)

RESPONSE

Errors in labeling will be corrected as part of the relabeling effort. This item will be corrected prior to issuance of an operating license.

FINDING

A.6.27 Abbreviations are not used consistently in labels. (6.30)

Examples:

a) Panel 206: CCW PUMP 2A (CCW = component cooling water)

b) Panel 203: CCW FROM RCP 2A1 FLOW (FIA-1158) (CCW = core cooling water)

c) Panel 205: COMP COOL'G WATER.

RESPONSE

Standardized abbreviations are to be employed during St. Lucie Unit No. 2 relabeling. Presently this item is scheduled for implementation prior to issuance of an operating license.

FINDING

A.6.28 Labeling of units on scales of trend recorders, counters, and process controllers on Panel 202 is inconsistent and often is redundant with the control label. (6.31)

Example:

a) FEEDWATER TO SG 2A REG VALVE BYPASS LIC-9005

RESPONSE

This item will be addressed as part of the St. Lucie Unit No. 2 relabeling effort. This effort is scheduled for implementation prior to fuel loading.

FINDING

A.6.29 Pushbuttons on Panels 201 and 203 have two labels which present redundant information. (6.32)

Example:

a) Panel 201: TURBINE TRIP and TRIP
b) Panel 203: RCP 2A1 VIBRATION RESET and RESET.

RESPONSE

Redundant labels will be removed. This item will be implemented prior to issuance of an operating license.

FINDING

A.6.30 Some labels are difficult to read due to insufficient color contrast between label surface and lettering. (6.34)

RESPONSE

Figure background contrast will be improved as part of relabeling. This item is scheduled to be implemented prior to issuance of an operating license.

FINDING

A.6.31 Engraved labels on all panels in the control room have become obscured by grime. (6.35)

RESPONSE

Relabeling will use black characters on a white background, reducing obscuration by grime. This effort is scheduled to be implemented prior to issuance of an operating license.

FINDING

A.6.32 On the Plant Auxiliary Panel, the annunciator control button labels are illegible and the ACKNOWLEDGE buttons are not labeled. (6.36)

RESPONSE

These controls will be appropriately labeled as part of the ongoing labeling study which is scheduled for implementation prior to issuance of an operating license.

FINDING

A.6.33 Panels 203 and 206 have labels whose characters are separated by less than the minimum recommended space (1/6 character height). (6.37)

RESPONSE

During St. Lucie Unit No. 2 relabeling, character spacing will conform to the requirements of NUREG-0700. This item is scheduled as part of the relabeling effort to be implemented prior to fuel loading.

FINDING

A.6.34 Line spacing is less than 1/2 character height on almost all labels in the control room. (6.38)

RESPONSE

During St. Lucie Unit 2 relabeling, line spacing will be 1/2 character height or greater. Line spacing will conform to the requirements of NUREG-0700 and will be implemented prior to fuel loading.

FINDING

A.6.35 Several controls on Panel 201 have temporary labels to indicate associated circuit breakers. (6.39)

RESPONSE

A review of existing labels (permanent and temporary) will be conducted. During St. Lucie Unit No. 2 relabeling all information will appear on permanent labels. This effort is scheduled for implementation prior to fuel loading.

FINDING

A.6.36 The permanent label for the STATION BATTERY 2B VOLTS meter is incorrect and has been replaced by a temporary label. However, both labels are still in place. (6.40)

RESPONSE

This will be corrected with correct, permanent labels. This labeling effort is scheduled for completion prior to fuel loading.

FINDING

A.6.37 On Panel 201, the label for the 480V BUS TIE SWITCH 2AB-2 is hand-written in ink on the panel surface. (6.41)

RESPONSE

A permanent label will be provided. This item is scheduled to be implemented prior to fuel loading.

FINDING

A.6.38 Tag outs on Panel 201 obscure displays located below them on the control panel. (6.42)

RESPONSE

A method of tagging which does not obscure adjacent switches will be implemented prior to issuance of an operating license.

FINDING

A.6.39 On Panel 201, summary labels and demarcation lines are not used to identify and separate systems surrounding mimics. Labels do not always appear above mimic areas. (6.43)

Example:

a) Electrical distribution buses

RESPONSE

Summary labeling and demarcation lines will be used to more clearly identify and separate those specific controls which are not associated with the surrounding mimic areas. This item will be completed prior to fuel loading.

FINDING

A.6.40 REACTOR TRIP A and C pushbuttons on Panel 201 are adjacent to the TURBINE TRIP pushbutton. REACTOR TRIP is a safety function and its controls should be readily distinguishable from the TURBINE TRIP control. (6.44)

RESPONSE

Reactor Trip pushbuttons will be conspicuously demarcated and labeled. This item is scheduled for implementation prior to issuance of an operating license.

FINDING

A.6.41 The color coding and shading of control labels on the HVAC Panel is inconsistent with the rest of the control room. (6.45)

RESPONSE

Any color coding of labels during the relabeling study will offer consistent color meanings. This item is scheduled for implementation prior to issuance of an operating license.

FINDING

A.6.42 Mimics in general are not consistently color coded. For example, there is an inconsistent use of color in the Power Distribution Mimic on Panel 201. The colors yellow and blue are used for voltages of 6.9KV and 4.16KV and yellow and blue are also used for protective channels B and D. (6.46)

RESPONSE

Consistent mimic color and codings means will be provided. This will be implemented prior to issuance of an operating license.

FINDING

A.6.43 On Panel 205, the annunciator TEST control is color coded red, which is inconsistent with coding of other annunciator controls. (6.47)

RESPONSE

This control will be changed to black. This backfit will be implemented prior to issuance of an operating license.

FINDING

A.6.44 The Line Repeat Panel Mimic has incomplete mimic lines and arrows. (6.48)

RESPONSE

The mimic will be completed. This item will be completed prior to fuel loading.

FINDING

A.6.45 Color codes of labels are generally based upon the power supply for the component instead of the component function. This color code scheme is helpful for maintenance but is not a useful aid for the operator. (6.49)

RESPONSE

The present labels are scheduled to be replaced with black on white labels; however, a small color dot indicator will be used to denote power train. Presently this item is scheduled to be completed prior to issuance of an operating license.

FINDING

A.6.46 There is a lack of grouping of Diesel Generator controls on Panel 201. (6.51)

RESPONSE

The Diesel Generator controls are grouped in accordance with the associated distribution system as depicted by the board mimic. Displays are located directly above associated controls.

Summary labeling and demarcation lines will be used to more clearly define grouping of associated diesel generator controls. This item will be implemented prior to issuance of an operating license.

A.8.0 PANEL LAYOUT

FINDING

A.8.1 On Panel 203, there is a lack of consistency in the column alignment of similar displays. For example, UPPER CAVITY PRESSURE indicators are not aligned vertically in the same column. (8.5)

RESPONSE

This is a labeling problem and not a lack of consistency. The span of the gauges indicates they are installed in a consistent manner. The labeling will be corrected prior to fuel loading.

FINDING

A.8.2 On Panels 205 and 206 it is difficult to locate and identify specific controls located in large matrices of controls which are identical in appearance. The control arrays do not have aids such as system funtional grouping, functional color coding, or demarcation to facilitate operator actions. (8.7)

RESPONSE

These control arrays will incorporate system functional grouping and demarcation to facilitate operator actions. This item will be implemented prior to issuance of an operating license.

FINDING

A.8.3 The indicator lights for DIESEL GEN. 2A LOADING status on Panel 201 are not arranged in the conventional operational loading sequence. (8.9)

RESPONSE

Loading sequence on Panel 201 will be arranged in a consistent manner prior to issuance of an operating license.

FINDING

A.8.4 On Panel 203, some controls are not arranged by importance or frequency of use. (8.10)

Examples:

a) ANNUNCIATOR controls
b) REACTOR COOLANT PUMP controls

RESPONSE

Presently the ANNUNCIATOR controls located on Panel 203 are scheduled to be moved to the lower right-hand corner of Control Board 204. These controls are scheduled for relocation prior to receiving an operating license.

FINDING

A.8.5 There is a poor grouping of indicator lights in several places on Panel 206. (8.11)

Examples:

a) CSAS CHANNEL SB
b) SIAS CHANNEL SB
c) RAS CHANNEL SB

RESPONSE

These controls and associated indicating lights will be demarcated to improve control/display relationships. This item is scheduled for implementation prior to issuance of an operating license.

FINDING

A.8.6 On Panel 203, several controls/displays are arranged horizontally on the upright panel while related controls/displays are arranged vertically on the benchboard. (8.12)

Example:

a) Reactor Coolant Pumps 2A1, 2A2, 2B1, 2B2

RESPONSE

These controls and displays will incorporate demarcation, hierarchical labeling, and summary labeling to better define these control/display relationships. This item is scheduled for implementation prior to fuel loading.

FINDING

A.8.7 There is a reversal from normal left-to-right convention of the indicator lights for the LPSI HDR A TO LOOP 2A1 VALVE and the LPSI HDR A TO LOOP 2A2 VALVE on Panel 206. (8.13)

RESPONSE

The arrangement of the HIPSI and LIPSI control displays will be reviewed and rearranged to complement the control/display demarcation effort. This item is scheduled for implementation prior to issuance of an operating license.

FINDING

A.8.8 The AUX FEEDWATER HEADER FLOW trend recorders on Panel 202 are arranged in BCA left-to-right sequence instead of ABC. (8.15)

RESPONSE

These recorders will be rearranged to conform to the control grouping. This item is scheduled for implementation prior to fuel loading.

FINDING

A.8.9 There are many locations in the control room where components are not arranged left-to-right and/or top-to-bottom, and are not identified in alphabetical or numerical sequence. (8.16)

Examples:

a) The HOLDUP TANK LEVEL INDICATORS on Panel 205 are arranged from right to left.

b) On Panel 206, the HDR B ISOL VALVE is above the HDR A ISOL VALVE.

RESPONSE

a) The HOLDUP TANK LEVEL INDICATORS will be rearranged to agree with left to right convention.

b) The HDR B and HDR A ISOL VALVE key operated switches and indicating lights will be rearranged to agree with top to bottom convention. These will be implemented prior to issuance of an operating license.

FINDING

A.8.10 The locations of LIQUID WASTE FLOW VALVES FCV-6627Y and FCV-6627X status indicator displays and valve control switch positions violate the upper/left - lower/right layout convention for associated controls and displays in a mixed horizontal and vertical layout. The upper set of indicator lights for valve Y is associated with the right position of the valve control. The lower set of indicator lights for valve X is associated with the left position of the control. (8.17)

RESPONSE

The light positions will be reversed to agree with left/right - top/bottom convention. This item will be implemented prior to issuance of an operating license.

FINDING

A.8.11 On Panel 206 the meter for SI TANK 2A2 LEVEL is a narrow range instrument. It should be a wide range meter to be consistent with similar level displays on the panel. (8.18)

RESPONSE

SI TANK 2A2 LEVEL instrument LIA-3311 will be replaced with the proper wide range indicator. This item will be implemented prior to fuel loading.

FINDING

A.8.12 There are excessively long meter strings of more than five vertical meters per string on Panels 201 and 203. (8.20)

Examples:

a) EXPANSION STEAM AREA
b) CONDENSER STEAM AREA

RESPONSE

Labels (summary and component) and demarcations will be provided to provide visual anchors breaking up strings into smaller groups. This item will be implemented prior to issuance of an operating license.

FINDING

A.8.13 There is string of 10 J-handles on Panel 203. It is difficult to readily distinguish individual controls in the string. (8.21)

RESPONSE

Labels (summary and component) and demarcations will be provided to provide visual anchors breaking up strings into smaller groups. This item will be implemented prior to issuance of an operating license.

FINDING

A.8.14 The REACTOR COOLANT PUMP 2B2 control on Panel 203 is located in a cluster with the PRESSURIZER BACKUP HEATER BANK controls. The pressurizer heater controls are used frequently. This location of the reactor coolant pump control among frequently operated controls increases the likelihood of accidental shutoff of the reactor coolant pump. (8.22)

RESPONSE

Finding to be resolved via demarcating and summary labeling of RCP controls, pressurizer relief controls, pressurizer heaters, and shape coding of RCP handles. This item to be implemented prior to issuance of an operating license.

FINDING

A.8.15 The CRT display on Panel 204 is difficult to view from the operator's position at the ROD POSITION CONTROLS because of the poor viewing angle. (8.23)

RESPONSE

The analog display is in close enough proximity to the CEA control panel to eliminate any viewing problem. This will be verified utilizing guidelines of NUREG-0700 prior to issuance of an operating license.

FINDING

A.8.16 Electrical test points for Reactor Coolant Temperature are included in front panel. If they are used only for calibration, they should be placed in other than prime control areas. If they are used for operations, they should be replaced by an appropriate display. (8.24)

RESPONSE

These test points will be relocated to another area prior to fuel loading.

A.9.0 CONTROL/DISPLAY INTEGRATION

FINDING

A.9.1 Panel 202 benchboard controls are mirror imaged while corresponding vertical displays are not. (9.2)

RESPONSE

The display associated with the Aux Feedwater controls on Panel 202 will be arranged to be consistent with the associated controls. This effort will be combined with the upgrade requirements of the Aux Feed system and is scheduled for implementation prior to issuance of an operating license.

FINDING

A.9.2 The right portion of Panel 202 contains 5 different subsystems (circulating water, condensate, primary makeup, intake, and screen wash), which are not arranged in a logical layout. (9.5)

RESPONSE

Demarcation will be implemented as an interim measure prior to issuance of an operating license. This item will be reviewed as part of the long term design review in accordance with NUREG-0700.

FINDING

A.9.3 Fisher-Porter controllers are inconsistent with each other. Some are fixed scale/moving pointer, while others are moving scale/fixed pointer. This requires operator to move the set point rotary wheel up to increase on some controls and down to increase on others. (9.6)

Examples: (Panel 205)

a) REACTOR MAKEUP FLOW (FRC-2210X)
b) FLASH TANK LEVEL (FCV-6627Y)

RESPONSE

a) Prior to issuance of an operating license "increase arrows" will be placed to clarify operation of those movable scale controllers.

b) These controllers will be reviewed in the Detail Control Room Design Review and reported on in accordance with NUREG-0700.

HUMAN ENGINEERING DISCREPANCIES THAT HAVE BEEN DOWNGRADED TO PRIORITY 3

This section contains a description of those discrepancies which have been downgraded to Priority 3. Following each discrepancy is a statement of the rationale for the downgrading provided by Florida Power and Light Company (FPL) and acceptable to the HFEB.

B.3.0 ANNUNCIATORS

FINDING

B.3.1 The annunciator system does not have a separate First Out Panel for the reactor systems. Annunciator Panel C, for the turbine, is the only annunciator panel with First Out reset capability. (3.5)

RESPONSE

The Sequence of Events Recorder is currently employed to print out sequence of events of Reactor Trip signals. The initiating signal is printed as part of this sequence. Therefore, the SER is the main means of identifying the cause of the trip. This item will be addressed as part of the long-term design review and reported on in accordance with NUREG-0700.

FINDING

B.3.2 On all annunciator panels, the only indication that an annunciated condition has been cleared is the extinguishment of the light. (3.7)

RESPONSE

The present annunciator system is consistent with Florida Power and Light's standard design philosophy. Clearing of an annunciator is indicative of a back to normal condition which is a safe condition and requires no operator action. It is felt that having the operator responsible for acknowledging return to normal conditions during a plant transient or other evolution requiring his attention could impede his judgement and affect his response time in reacting to a given situation. This item will be reviewed as part of the long-term design review and reported on in accordance with NUREG-0700.

FINDING

B.3.3 Some annunciators used in startup will be normally lit during full-power operation. (3.11)

Examples:

a) POWER HIGH RANGE OF CHANGE and TRIP BYPASSED tiles on annunciator Panel L

RESPONSE

An engineering review will be conducted to identify annunciators which will be normally lit during full-power operations. This item will be reviewed as part of the detail design review and reported on in accordance with NUREG-0700.

FINDING

B.3.4 The operator cannot read all of the annunciator tiles on Panels 205 and 206 from the annunciator acknowledge control location because of the oblique viewing angle from the control location. (3.16)

RESPONSE

The operator would walk to the annunciator panel regardless of the location of the acknowledge control. This item will be included as part of the detailed control room design review reported on in accordance with NUREG-0700.

B.4.0 CONTROLS

FINDING

B.4.1 The Fire Pump 1A and 1B Stop controls on Panel 202 are unnecessary controls to that panel. These controls are not related to systems operations controlled from that panel. (4.2)

RESPONSE

The Fire Pump controls will be reviewed as part of the long-term effort and reported as part of NUREG-0700.

B.5.0 DISPLAYS

FINDING

B.5.1 On Panel 204, the CEA Secondary Rod Position display is made up of a high contrast checkerboard pattern of bright yellow on white. This pattern is very disturbing to look at because of color afterimages. (5.9)

RESPONSE

This will be the subject of the long-term review and reported on in accordance with NUREG-0700.

FINDING

B.5.2 Multipoint impact recorders have too many data channels on each recorder. Some recorders have as many as 24 data channels. Similar impact recorders in Unit 1 were found to be overprinting their data. (5.29)

RESPONSE

These impact recorders are used for trend values. An off-normal condition would be seen as a departure from normal trend at which time the point would be readable. This will be looked at as part of the long-term review in accordance with NUREG-0700.

B.8.0 PANEL LAYOUT

FINDING

B.8.1 On Panel 206 unrelated displays have been placed between related displays for CCW FROM SHUTDOWN, CCW FROM FUEL POOL, and CONTAINMENT SPRAY. (8.3)

RESPONSE

Florida Power and Light will review this item as part of the detailed control room design review and it will be reported on in accordance with NUREG-0700.

FINDING

B.8.2 The VOLUME CONTROL TANK DISCH VALVE V-2501 and the REFUELING WATER TO CHARGING PUMPS VALVE V-2504 on Panel 205 are spatially separated by other letdown, charging and VCT controls. There is a general lack of logical layout of charging, letdown, and VCT controls on this panel for task oriented optimization. (8.4)

RESPONSE

This item will be incorporated into long-term review and reported in accordance with NUREG-0700.

FINDING

B.8.3 The CONDENSATE STORAGE TANK HIGH LEVEL and CONDENSATE LOW LEVEL annunciator tiles on annunciator Panel Q are not near or above associated system displays. (8.5)

RESPONSE

The CONDENSATE STORAGE TANK HIGH LEVEL and LOW LEVEL annunciator tiles are located on Panel G, not on Panel Q. Panel G is located on Control Board 202 and the displays are located 4 feet to the right and are readable from the associated control location. The annunciator display relationship will be addressed as part of the long-term review in accordance with NUREG-0700.

B.9.0 CONTROL/DISPLAY INTEGRATION

FINDING

B.9.1 There is little system functional logic to the layout of Panel 205. For example, a normal blending operation would involve the use of the BORIC ACID MAKEUP PUMP 2A, the BORIC ACID MAKEUP FLOW VALVE, the REACTOR MAKEUP WATER STOP VALVE, and the REACTOR MAKEUP FLOW VALVE controls and the indicators for BORIC ACID FLOW, REACTOR MAKEUP WATER FLOW and VOLUME CONTROL TANK LEVEL. These controls and displays are not logically grouped to perform this operation. (9.1)

RESPONSE

This item will be incorporated into the long-term review and reported on in accordance with NUREG-0700.

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U.S. NUCLEAR REGULATORY COMMISSION

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15. SUPPLEMENTARY NOTES Pertains to Docket No. 50-389	14. *(Leave blank)*

16. ABSTRACT *(200 words or less)*

Supplement No. 1 to the Safety Evaluation Report for the application filed by Florida Power & Light Company for a license to operate the St. Lucie Plant, Unit No. 2 (Docket No. 50-389), located in St. Lucie County, Florida has been prepared by the Office of Nuclear Reactor Regulation of the Nuclear Regulatory Commission. The purpose of this supplement is to update the Safety Evaluation Report by providing (1) an evaluation of additional information submitted by the applicant, (2) an evaluation of the matters the staff had under review when the Safety Evaluation Report was issued, and (3) a response to comments made by the Advisory Committee on Reactor Safeguards.

17. KEY WORDS AND DOCUMENT ANALYSIS

17a. DESCRIPTORS

17b. IDENTIFIERS/OPEN-ENDED TERMS

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