UNITED STATES
NUCLEAR REGULATORY COMMISSION
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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

FOR UNRESOLVED SAFETY ISSUE A-46 PROGRAM IMPLEMENTATION

OCONEE NUCLEAR STATION, UNITS 1, 2, AND 3

INCLUDING KEOWEE HYDRO STATION AND SWITCHYARD

DOCKET NOS. 50-269, 50-270, AND 50-287

1.0 BACKGROUND

In December 1980, the Nuclear Regulatory Commission (NRC) designated "Seismic Qualification of Equipment in Operating Plants" as Unresolved Safety Issue (USI) A-46. The safety issue of concern was that equipment in nuclear plants for which construction permit applications had been docketed before about 1972 had not been reviewed according to the 1980-81 licensing criteria for the seismic qualification of equipment, such as Regulatory Guide (RG) 1.100 (Reference 1), IEEE Standard 344-1975 (Reference 2), and Section 3.10 of the Standard Review Plan (NUREG 0800, July 1981) (Reference 3). To address USI A-46, affected utilities formed the Seismic Qualification Utility Group (SQUG) in 1982.

The NRC staff issued Generic Letter (GL) 87-02 "Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors," in February 1987 (Reference 4) to provide guidance for the resolution of USI A-46. The staff concluded that the seismic adequacy of certain equipment in operating nuclear power plants should be reviewed against seismic criteria not in use when these plants were being constructed. In 1987, SQUG, representing its member utilities, committed to develop a Generic Implementation Procedure (GIP) for implementing the resolution of USI A-46. SQUG requested a deferment of the 60-day response, as requested in GL 87-02, until after the NRC issued its final safety evaluation report (SER) on the final version of the GIP. In 1992, SQUG developed the "Generic Implementation Procedure (GIP) for Seismic Verification of Nuclear Plant Equipment," Revision 2 (GIP-2, Reference 5).

On May 22, 1992, the NRC issued Supplement 1 to GL 87-02 including the staff's Supplemental Safety Evaluation Report No. 2 (SSER-2, Reference 6), pursuant to the provisions of 10 CFR 50.54(f). It requested that all addressees provide either (1) a commitment to use both the SQUG commitments and the implementation guidance described in GIP-2 as supplemented by the staff's SSER-2, or (2) an alternative method for responding to GL 87-02. The supplement also requested that those addressees committing to implement GIP-2 provide an implementation schedule as well as detailed information including the procedures and criteria used to generate the in-structure response spectra (IRS) to be used for the USI A-46 program.

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By letters dated September 21, 1992 (Reference 7), January 15, 1993 (Reference 8) and March 3, 1993 (Reference 9), Duke Power Company (DPC)[1], the licensee for the Oconee Nuclear Station (ONS), Units 1, 2, and 3, responded to Supplement 1 of GL 87-02 for ONS, which included the Keowee Hydro Station and switchyard. The response also provided a commitment to implement GIP-2, including the clarifications, interpretations, and exceptions in SSER-2, and a description of the procedures used to generate IRS to be used for USI A-46 implementation. The staff's evaluation of DPC's response was issued in letters dated November 19, 1992 (Reference 10) and April 5, 1993 (Reference 11). The staff found the DPC commitment to be acceptable and concluded that the IRS was to be treated as "median centered" rather than "conservative design." DPC conducted the USI A-46 program and submitted the original summary report in two parts dated December 30, 1996 (Reference 12) and December 15, 1997 (Reference 13). By letter dated September 28, 1998, DEC submitted Revision 1 (Reference 14) to Reference 13 to include information associated with the emergency condenser circulating water (ECCW) system upgrade modifications. Revision 1 (Reference 14) replaced the second part of the original submittal (Reference 13) in its entirety. The staff reviewed the summary report (References 12 and 14) and requested additional information (RAI) on February 18, 1999 (Reference 15). DEC responded to the staff's RAI on May 14, 1999 (Reference 16). The staff has completed its review of this response.

This report provides the staff evaluation of the licensee's USI A-46 implementation program based on the staff's review of the summary report, supplemental information, and clarification provided by the licensee in response to the staff's RAIs.

2.0 DISCUSSION AND EVALUATION

The staff reviewed the summary report (References 12 and 14) of the USI A-46 program implementation at ONS in accordance with the USI A-46 Action Plan, dated July 26, 1994 (Reference 17). The effort consisted of a screening of specific sections of the licensee's program, with emphasis placed on identification and resolution of outliers; i.e., equipment items that do not comply with all the screening guidelines provided in GIP-2. The report identifies a safe shutdown equipment list (SSEL) and contains the screening verification and walkdown of mechanical and electrical equipment. The report also contains relay evaluations and the evaluation of the seismic adequacy for tanks and heat exchanges, cable and conduit raceways, and the identification and resolution of outliers, including the proposed resolution schedule.

2.1 Seismic Demand Determination (Ground Spectra and In-structure Response Spectra

The ONS site could be characterized as bedrock overlaid by a shallow layer of overburden soil. Except for the water storage tanks, the Switchyard, and the outside transformers, which are founded on overburden, all major structures are founded on rock. The safe shutdown

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[1]By NRC letter dated September 16, 1997, the licensee's name was officially changed from Duke Power Company (DPC) to Duke Energy Corporation (DEC). The names are used interchangeably in this document.

earthquake (SSE) for the site is 0.1g for rock and 0.15g for soil condition. The licensing basis spectrum, which is of the Housner type, was used as the ground response spectrum (GRS).

The IRS were generated via time history analysis using the 1940 N-S El Centro earthquake time history scaled to the SSE as input. In Figure 2 of Enclosure 2 to the licensee's response to the staff's request for additional information (Reference 16), a comparison of the El Centro N/S spectrum to the ONS ground spectrum indicates that the El Centro spectrum completely envelopes the ONS ground spectrum, and at frequencies of interest, the El Centro spectrum is 50 percent higher than the ONS ground spectrum.

The method for developing the IRS was described in the ONS USAR 3.7.1.2 (Reference 18), and was evaluated and accepted for use in the implementation of the USI A-46 program by the staff, as documented in Reference 10. However, the staff stated in its evaluation that the IRS should be treated as "median-centered" rather than "conservative, design" as the licensee characterized.

2.2 Seismic Evaluation Personnel

As stated in the summary report (References 12 and 14) by DPC, a SQUG project team was established at ONS in 1992 to address issues relating to USI A-46. This team was multi-disciplinary and was responsible for overall project coordination, performing relay evaluations and seismic walkdowns, and the coordination of contractor activities. This team included engineers involved with structural, electrical, and control disciplines and was augmented with contract engineers. The team was assisted by on-site mechanical and electrical systems engineers. A third party audit team, consisting of senior engineers from DPC and its contractor, was formed and provided independent audit reviews. All seismic capability engineers were licensed professional engineers trained in accordance with the provisions of GIP-2. The majority of these engineers were from DPC's contractor. The third party audit team consisted of experienced DPC engineers familiar with ONS and senior engineers from DPC's contractor.

The ONS SQUG project team coordinated all activities and performed relay evaluations and seismic walkdowns. The seismic capability engineers performed all equipment seismic evaluations. A team of on-site mechanical and electrical system engineers developed the SSEL and provided guidance as needed to the project team. DPC's contractor personnel performed the seismic walkdowns and the resolution of outliers.

The staff finds that DPC's seismic evaluation personnel qualifications meet the provisions of GIP-2 and the staff's SSER-2; therefore, the staff finds them acceptable for the resolution of USI A-46 at ONS.

2.3 Safe Shutdown Path

GL 87-02 specifies that licensees should be able to bring the plant to, and maintain it in, a hot shutdown condition during the first 72 hours following an SSE. To meet this provision, in its submittal of September 28, 1998 (Reference 14), the licensee addressed the following plant safety functions: reactor reactivity control, pressure control, inventory control, and decay heat removal. Primary and alternate safe shutdown success paths with their support systems and instrumentation were identified for each of these safety functions to ensure that the plant is capable of being brought to, and maintained in, a hot shutdown condition for 72 hours following an SSE. Appendix B to the summary report (References 12 and 14) provides the SSEL.

The reactor decay heat removal function is accomplished by relieving steam via the main steam safety valves from the reactor by establishing natural circulation conditions through the steam generators (SGs) until such time that the decay heat decreases to the point where atmospheric dump valves can be used. The operator would open the atmospheric dump valves to establish a plant cooldown. Makeup water to the SGs will be supplied by the emergency feed water (EFW) system which takes suction from the upper surge tank and condenser hotwell. These water supplies ensure sufficient capacity to cool down the reactor to low pressure injection (LPI) entry conditions and to maintain the plant in cold shutdown conditions.

The operators have another alternative available to implement the primary "feed-bleed" mode of cooling. In this mode of operation the operators would be opening the pressurizer power-operated relief valve (PORV) and establishing the high pressure injection (HPI) system, which takes suction from the borated water storage tank (BWST). When this water source is exhausted, core cooling can be maintained by using the LPI system in combination with the HPI system in the "piggy-back" mode. The LPI system would take suction on the reactor building (RB) sump and recirculate the water through the RHR heat exchangers, to the HPI system, and into the reactor. The equipment necessary for the "feed-bleed" method of decay heat removal are listed in the Appendix B of the summary report (References 12 and 14).

The plant operations department reviewed the equipment listed in the SSEL against the plant operating procedures and operator training and concluded that the plant operating procedures and operator training were adequate to establish and maintain the plant in a safe shutdown condition following an SSE.

Based on the above, the staff concludes that the approach to achieve and maintain a safe shutdown for 72 hours following a seismic event is acceptable for the resolution of USI A-46 at ONS.

2.4 Seismic Screening Verification and Walkdown of Mechanical and Electrical Equipment

The review of the seismic adequacy of mechanical and electrical equipment in the ONS SSEL was performed in accordance with Section II.4 of GIP-2. The equipment screening verification and walkdowns involved review of 1715 equipment items installed at the ONS site and the associated Keowee hydroelectric station, and resulted in 470 equipment items being designated as outliers. The walkdowns were performed by seismic review teams (SRTs) consisting of a minimum of two Seismic Capability Engineers in each team. All equipment walkdowns were performed between 1993 and 1998. Signed screening verification data sheets (SVDS) for each SSEL equipment item, are contained in Appendix D of the summary report (References 12 and 14).

2.4.1 Equipment Seismic Capacity Compared to Seismic Demand

The components on the seismic SSEL at the ONS site are housed in the following nine structures:

- Auxiliary building (AB)
- Intake structure
- Reactor building
- Essential siphon vacuum building
- Radwaste facility
- Turbine building (TB)
- Safe shutdown facility (SSF)
- Transformer and switchgear enclosure
- Yard

The emergency power for the ONS safe shutdown functions is provided by the Keowee hydro station, which is located about one mile from the Oconee plant itself. The Keowee station, which was not originally designed for seismic loads, was included for seismic evaluation under the USI A-46 program. The main structure at Keowee is the powerhouse, which is founded on rock and houses most of SSEL equipment. The remaining SSEL equipment listed below are founded on overburden soil:

- 230 kV Switchyard and relay house
- Keowee main transformer
- Underground power path

The effective grades of the ONS and Keowee structures were identified and provided in the licensee submittals.

For the seismic capacity versus demand evaluation of equipment on the seismic SSEL, DPC elected to use Method A.1 of GIP-2, Section II.4.2 [bounding spectra (BS) versus design basis SSE ground spectra], provided the requirements for the equipment fundamental natural frequency of about 8 Hz or greater and the equipment location of less than about 40 feet above effective grade are satisfied. Otherwise, Method B.1 of GIP-2, Section II.4.2 (1.5 x BS versus applicable IRS) was used. Primarily due to lack of available seismic testing information, generic equipment ruggedness spectra (GERS) were used on a very limited basis for comparison of seismic capacity to seismic demand. It is noted that for both Methods A.1 and B.1, 5 percent damping was applied. In the summary report, the licensee stated that the ONS site GRS for structures founded on both soil and rock are fully enveloped by the SQUG-BS.

Method A.1 of GIP-2 was developed based on past experiences with typical nuclear power plant structures; however, GIP-2 places certain limitations on the use of Method A.1. These limitations are that SSE GRS can be used for comparison to the BS when:

- The equipment is mounted in the nuclear plant at an elevation below about 40-feet above the effective grade.

- The equipment, including its support, has a fundamental natural frequency greater than about 8 Hz.

- The amplification factor between the GRS and the IRS is not more than about 1.5.

In the licensee's response (Reference 16) to the NRC RAI question No. 9 (Reference 15), the TB at ONS was identified as having an amplification factor that significantly exceeded 1.5 at elevation 760 feet. The licensee attributed the high amplification factor to conservatism in the calculation of the TB IRS, and provided a detailed discussion of the conservatism in Enclosure 2 to the licensee's response (Reference 16), which is evaluated below.

Enclosure 2 discussed conservatism associated with the development of the IRS for ONS. Of these, the time history simulation, structural damping and peak clipping for narrow peaks may result in significant over-prediction for the IRS, especially the ground-input spectrum (El Centro) for IRS generation, which is about 1.7 times the ONS design-basis ground spectrum at the frequencies of interest. Since the IRS for the TB could be as high as 11 times the design-basis ground spectrum, it is doubtful that by removing the conservatism identified above, the amplification factor will be limited to within 1.5. However, examination of the comparison between the TB IRS and 1.5 x B.S. indicates that the TB IRS will be fully enveloped by the 1.5 x B.S., if these conservatisms are to be removed. Therefore, Method B.1 of GIP-2 could be applied to the TB as an alternative, and thus the results of the demand versus capacity comparisons for ONS are consistent with the GIP-2 requirements.

Components on SSEL that could not be screened out using either Method A or Method B of the GIP-2, Section II.4.2 were considered capacity outliers. A total of 101 capacity outliers were identified during the walkdowns, with 39 of these having been resolved. Outlier resolutions were based on the use of existing test reports or detailed calculations to verify that capacity exceeds demand for the equipment item. Similar methods have been proposed to resolve the outstanding outliers. DPC expects to resolve all outliers within 120 days of the end of INNAGE[2] 73, which is currently scheduled for June 2, 2002 (Reference 19).

2.4.2 <u>Assessment of Equipment "Caveats"</u>

DPC screened equipment caveats to confirm that the equipment characteristics are similar to the earthquake experience class or the generic seismic testing equipment class, so that the seismic adequacy of an item of mechanical or electrical equipment could be assessed using the B.S. or GERS to represent the seismic capacity of the item. The walkdown caveat checks are documented on the screening evaluation work sheets (SEWS) and the results are summarized in column 13 of the SVDS in Appendix D of the summary report (References 12 and 14).

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[2]INNAGE describes the period of time between startup of a facility following a refueling outage to its shutdown for the next refueling outage.

DPC included a listing of all equipment class specific caveats on the SEWS for each class of equipment. The SRTs were required to consider all the caveats for each item reviewed, indicating whether the item met the caveat, did not meet the caveat, or met the intent of the caveat. In the last case the SRTs listed directly on the SEWS the basis for their judgement. A review of SEWS provided in the licensee responses (Reference 16) to NRC RAIs showed that the caveat checks were made and appropriate explanations provided where the intent option was used for compliance. Equipment that did not meet the GIP-2 B.S. caveats (or intent) were identified as outliers.

A total of 210 items of equipment did not satisfy the B.S. caveats and were identified as B.S. outliers. Of these, 78 were resolved using existing test reports, manufacturers test reports, or item-specific calculations to determine the seismic capacity of the item. The methods proposed to resolve the outstanding outliers include using existing test reports and detailed calculations to demonstrate adequate seismic capacity or improving seismic capacities by the implementation of equipment/anchorage modifications. DPC expects to resolve all outliers within 120 days of the end of INNAGE 73 (presently scheduled for June 2, 2002).

In an NRC RAI dated February 18, 1998 (Reference 15), the staff requested the licensee to provide clarification of the determination that selected items of equipment at the Keowee hydroelectric station met the intent but not the letter of the caveats. The licensee provided the basis for these determinations in their response (Reference 16). Essentially, for all the equipment items, the determination was based on the judgement that additional features or aspects of the design of each item enhanced its seismic capacity and made it acceptable.

DPC's approach for identifying and assessing equipment caveats is reasonable and consistent with the GIP-2 guidelines and the staff's SSER-2. The staff finds it acceptable for the resolution of USI A-46 at ONS.

2.4.3 Equipment Anchorage

DPC assessed the seismic adequacy of equipment anchorage during the walkdowns and documented the results of the evaluations on the SEWS forms that are summarized in column 14 of the SVDS in Appendix D of the summary report (References 12 and 14).

As stated in Section 5.1.3 of the summary report, equipment anchorages were verified in accordance with the methodology provided in Section II.4.4 and Appendix C of GIP-2. This involved a screening approach based upon a combination of inspections, analyses and engineering judgement. In these evaluations, the larger of the A-46 or the Individual Plant Examination of External Events (IPEEE) accelerations, increased by a factor of 1.25 in accordance with GIP-2, were used. The anchorage of all SSEL items, with the exception of in-line valves or temperature sensors, was visually inspected. The anchorage types included expansion anchors, cast-in-place and grouted-in-place bolts, welds to embedded steel, and bolts to structural frames.

In the process, equipment mass and center of gravity were determined from plant documentation or conservatively estimated. Accessible anchorages were visually inspected, and the sizes and locations of anchors verified. Expansion anchors were tested for tightness.

Embedment lengths of cast-in-place or grouted-in-place anchors were verified from as-built drawings and from the length stamp on anchor ends. Shell type anchors were visually spot-checked to assure that the shell did not protrude above the concrete surface nor touch the base of the equipment. The presence and size of any gaps between the base and equipment item, minimum spacing requirements, minimum edge distance, and evidence of significant cracks in concrete at anchors were determined. Capacity reduction factors as given in Section C.2.8 of Appendix C of GIP-2 were applied to any anchor not meeting the required conditions. The seismic adequacy of anchorages were determined by comparing the anchor capacity to the applied load using the shear-tension interaction formulations given in Appendix C of GIP-2. Electrical equipment anchorage was typically evaluated using the computer program EBAC, while the anchorage for tanks and heat exchanges was evaluated exclusively by hand calculation.

Any anchorage that was determined to be deficient or was not covered in GIP-2 guidelines was determined to be an outlier. A total of 184 anchorage outliers were identified with 73 of these having been resolved. Detailed calculations and the performance of in-field tug tests for distribution panels were the methods used to resolve the majority of closed anchorage outliers. Proposed methods to resolve the outstanding anchorage outliers include the addition of bracing, the replacement of deficient anchor components, the enhancement of welds, the addition of additional restraints and the modification of anchorage. DPC expects to resolve all outliers within 120 days of the end of INNAGE 73 (presently scheduled for June 2, 2002).

The approaches used by DPC to ensure the adequacy of equipment anchorage are consistent with the GIP-2 guidelines and the staff's SSER-2 and are considered an acceptable means for the resolution of USI A-46 at ONS.

2.4.4 Seismic Spatial Interaction Evaluation

DPC assessed the possibility of seismic interactions during the screening walkdowns. The interaction evaluation findings are documented on the SEWS forms and in column 15 of the SVDS in Appendix D of the summary report (References 12 and 14).

The seismic interaction evaluation is the fourth and final screening criterion which must be satisfied to verify the seismic adequacy of SSEL equipment. As stated in Section 5.1.4 of the summary report, the possibility of seismic interactions were evaluated during the field walkdowns. The effects evaluated included interaction with items in proximity with the inspected item, the possibility of structural failure or falling, and the flexibility of attached lines and cables. The guidance provided in Section II.4.5 of GIP-2 was used to identify only those interaction issues that were determined to be credible and significant. Since block walls exist at ONS, their possible failure and potential interaction with SSELs was evaluated.

A total of 81 seismic interaction outliers were identified during the walkdowns, of which 7 have been resolved. Outlier resolutions were based on revised calculations to confirm seismic capacity and by structural modifications. The methods proposed to resolve outstanding outliers include equipment modification, bracing of adjacent block walls, the restraint or removal of adjacent equipment items, adding padding between equipment items and adjacent wall/equipment and analysis. DPC expects to resolve all outliers within 120 days of the end of INNAGE 73 (presently scheduled for June 2, 2002).

Approximately 75 masonry walls were identified which were not seismically qualified during the IE Bulletin 80-11 program implementation and therefore required detailed review. Of these, 65 percent were qualified either by comparison to existing calculations or with a unique calculation. The licensee provided an example of a unique wall calculation in its response (Reference 16) to NRC RAI Question No. 12 (Reference 15). The calculation used a combination of the IE Bulletin 80-11 design parameters and comparisons to a similar seismically-qualified wall to demonstrate the seismic adequacy of the walls in question. The calculation was considered sufficient to support its conclusion. DPC expects to resolve all other outliers within 120 days of the end of INNAGE 73 (presently scheduled for June 2, 2002). DPC's evaluations of spatial seismic interactions are consistent with the GIP-2 guidelines and the staff's SSER -2. The staff finds them acceptable for the resolution of USI A-46 at ONS.

2.5 Tanks and Heat Exchanger

DPC evaluated a total of 78 tank and heat exchanger units at the ONS site and 24 tank and heat exchanger units at the Keowee Hydro Station in the USI A-46 program. The results of these evaluations are documented on the SEWS forms and are summarized in the SVDS in Appendix D and Section 6 of the summary report (References 12 and 14).

As stated in Section 6.1 of the summary report, the tanks and heat exchanges on the ONS SSEL were evaluated in accordance with the rules and procedures described in Section II.7 of GIP-2. The tanks were located in the SSF, the yard, the RB, AB, and TBs at the ONS site and in the Keowee building. The units were supported/anchored with J-bolts, saddles/structural bolts, saddles/clip bolts, welds and anchor bolts, and concrete pad/clip bolts.

All of the 24 tank and heat exchanger units at Keowee and 44 of the 78 units at the ONS site were considered outliers. The majority of the outliers were due to the support configurations considered not to be within the scope of GIP-2. Examples of these are tanks and heat exchanges supported on legs, vertical tanks not supported continuously over their bottom and tanks not cylindrical in shape. Table 6-2 of the summary report provides a summary of the outliers and their resolution. All of the outliers have been resolved. For all but the upper surge tanks, the resolution was stated to have been made with calculations to verify seismic adequacy or through the use of engineering judgement. For the upper surge tanks, modifications were made to upgrade their seismic capacity.

A review of SEWS and calculations provided in the licensee response (Reference 16) to NRC RAI question No. 10 (Reference 15) showed that the seismic adequacy of a unit was determined by engineering judgement in 3 out of 4 cases, while a unit anchorage was assessed by calculation in all four cases. In the same response, the licensee corroborated that liquid sloshing effects were included in the calculations.

DPC's evaluation of tanks and heat exchanges is consistent with the GIP-2 guidelines and the staff's SSER-2 and is considered acceptable for the resolution of USI A-46 at ONS.

2.6 Cable and Conduit Raceways Supports

DPC assessed the seismic adequacy of cable trays, conduits, and cable trenches in accordance with the GIP-2 guidelines. With a similar methodology, DPC also assessed the seismic adequacy of the ONS facility control room ventilation system (CRVS) ducting in the USI A-46 program. The cable tray and conduit walkdowns were documented on area summary sheets, and the results of the evaluations are described in Section 7.1.4 of the summary report (References 12 and 14) with a complete outlier description and proposed resolution summary provided in Tables 7-1 and 7-2 of that section. A summary of the cable trench review is provided in Section 7.2 of the report. The results of the CRVS evaluation are described in Section 7.3.3 of the report with a complete outlier description and proposed resolution summary provided in Table 7-4 of that section.

As stated in Section 7.1.1 of the summary report, the reviews of cable tray and conduit systems for the ONS facility were performed in accordance with the guidelines of Section II.8 of GIP-2. The tray system walkdowns and reviews were performed by teams comprised of two SEES, each is a licensed professional engineer, with technical support from an on-site DPC engineer. No effort was made to determine the routing of SSEL-related cables, and therefore, all cable trays in the ONS facility, including those in the Keowee hydro station, were reviewed. All of the cable trays at ONS were of the ladder type, braced laterally and axially. The majority of the tray supports were the trapeze-type constructed of Unistrut channels supported from the ceiling. DPC selected 588 cable tray bounding samples for limited analytical review. These were all of the systems in the RBs, 45 samples from the balance of the systems at the ONS site, and four samples at the Keowee hydro station. All of the systems in the RBs were evaluated, since they were all similar and an automated analysis method was used for their evaluations. Conduit systems were all determined to be obviously adequate during walkdown, and no bounding sample was evaluated.

A review of four limited analytical reviews, provided in the licensee's response (Reference 16) to NRC RAI Question No. 13 (Reference 15), indicated that the reviews were comprehensive and consistent with the GIP-2 guidelines. Of the bounding samples, 23 did not meet the GIP-2 criteria, with seven of those being resolved by analysis. The remaining 16 samples, involving 56 supports, will be resolved by performing support modifications. Seventy-five outliers were identified during the walkdown. Of these, 33 have been resolved, 22 involve block walls, and 20 involve 36 supports that will require support modifications. For the outliers related to block walls, the resolution will involve verifying the seismic adequacy of the wall or confirming that the affected raceways do not carry cable for SSEL equipment. DPC expects to resolve all outliers within 120 days of the end of INNAGE 73 (presently scheduled for June 2, 2002). DPC's evaluation of cable and conduit raceway supports is consistent with the GIP-2 guidelines and the staff's SSER-2 and is considered acceptable for the resolution of USI A-46 at ONS.

Heating, ventilation, and air conditioning (HVAC) systems are not explicitly addressed in GIP-2. In order to evaluate the CRVS HVAC duct systems, DPC's contractor developed an evaluation approach for HVAC systems that was similar to the evaluation methodology for cable tray systems in GIP-2. A description of the HVAC system evaluation methodology was provided to the staff in the licensee response (Reference 16) to NRC RAI Question No. 14 (Reference 15). The methodology included the delineation of duct run and duct support attributes to be assessed, the walkdown of the systems, the identification and analysis of bounding configurations, and the identification and resolution of outliers. The characterization of acceptable HVAC attributes was based on industry standards and experience data records that were kept by EQE, Inc. Twenty-two HVAC system outliers were identified. Of these, nine have been resolved with calculations, six involve block walls, and the remainder will require modifications. For the block wall outliers, resolution will require verifying the seismic adequacy of the walls. DPC expects to resolve all outliers within 120 days of the end of INNAGE 73 (presently scheduled for June 2, 2002). DPC's evaluation of the CRVS was comprehensive and is considered comparable to the GIP-2 guidelines for distributive systems. The staff finds it acceptable for the resolution of USI A-46 at ONS.

A review of cable trenches was made with an evaluation of the impact of an IPEEE seismic event on essential control and power cables. It involved making an upper-bound estimate of the maximum ground strain that can be produced by a propagating seismic wave and comparing it to the strain that can be accommodated by the cable trenches. The estimates of the strain capacity of the cable trenches were stated to exceed the estimated maximum ground strain produced by the seismic wave by factors of 8 to 20. Since the definition of seismic input for the IPEEE event enveloped the A-46 seismic input by a large margin, DPC concluded that the evaluation results resolved the issue for the A-46 program. The NRC is evaluating DPC's IPEEE program and has not raised any issues related to the cable trench review. It is, therefore, considered acceptable for the resolution of USI A-46 at ONS.

A last item of review related to cables is the 230 KV overhead power transmission lines between the Keowee hydro station and the ONS site. In the licensee response (Reference 16) to NRC RAI Question No. 5 (Reference 15), the licensee provided a description of the ONS USI A-46 evaluation for these lines. In its response, the licensee stated that the transmission lines were determined to be adequate for the USI A-46 seismic demands using conservative analytical methods and earthquake experience data. The lines are included in the SSEL and the results of their evaluations are documented on the SVDS. The staff finds the methods used to evaluate the power transmission lines acceptable for the resolution of USI A-46 at ONS.

2.7 Essential Relays

DPC performed a review of relays associated with SSEL equipment and documented the effort in the relay evaluation report, a companion volume to the seismic evaluation report, and part of the summary report (References 12 and 14). The relays evaluated are listed in the relay review SSEL, Table 4-1 of the relay evaluation report. The relay walkdown and evaluation results are documented on the USI A-46 relay screening and evaluation form G.4, Table 5-1 of the relay evaluation report. A summary of relay outliers is provided in Table 2-2 of the summary report.

As stated in Section 2 of the relay evaluation report, the functional review of relays was performed in accordance with Section II.6 of GIP-2. Relay type, location in a cabinet, and mounting were spot checked by the walkdown teams. Relays whose contact chatter could cause a system or component to be placed in an undesirable state were identified as "essential relays." Relay amplification factors were determined based on equipment classification and then verified or conservatively assumed based on their location in the cabinet. Equipment classes were selected based on the guidance provided in GIP-2 and in EPRI reports

NP-7147-SL and NP-7148-SL. All of the relay population were evaluated using GERS, the switchgear relay method in GIP-2, seismic test reports, and seismic analyses. Examples of the application of these methods provided in the licensee response (Reference 16) to staff RAI Question No. 8 (Reference 15) were reviewed and found to be correctly implemented.

A total of 5031 relays were reviewed at the ONS, Units 1, 2, and 3, in the USI A-46 program. Of these, 1825 were determined to be chatter acceptable, 1578 were not vulnerable to contact chatter, 1538 were determined by the screening methods to have adequate seismic capacity, and 90 were identified as outliers. The outliers were items from 12 relay models. One group of 6 has been resolved using an alternate analysis method. For the others, the methods proposed for resolution include testing in accordance with the seismic qualification reporting and testing standardization (SPURTS) program and replacement with a seismically adequate equivalent.

A total of 1205 relays associated with the Keowee hydro station were reviewed in the USI A-46 program. Of these, 585 were determined to be chatter acceptable, 170 were not vulnerable to contact chatter, 311 were determined by the screening methods to have adequate seismic capacity, and 139 were identified as outliers. The methods proposed to resolve the outliers are similar to the methods described above for the ONS, Units 1, 2, and 3. DPC expects to resolve all outliers within 120 days of the end of INNAGE 73 (presently scheduled for June 2, 2002).

DPC's assessment of essential relays was consistent with the GIP-2 guidelines and the staff's SSER-2. Therefore, the staff finds the licensee's essential relay evaluation acceptable for the resolution of USI A-46 at ONS.

2.8 Human Factors Aspect

As part of the resolution of USI A-46, SQUG developed GIP-2 for use, in part, by licensees to identify and verify an SSEL and ensure adequate procedures and training were in place for plant operators to mitigate the consequences of an SSE.

GIP-2 described the use of operator action as a means of accomplishing those activities required to achieve safe shutdown. Section 3.2.7, "Operator Action Permitted," states, in part, that timely operator action is permitted as a means of achieving and maintaining a safe shutdown condition provided procedures are available and the operators are trained in their use. Additionally, Section 3.2.6, "Single Equipment Failure," states that manual operator action of equipment that is normally power operated is permitted as a backup operation provided that sufficient manpower, time, and procedures are available. Section 3.2.8, "Procedures," states, in part, that procedures should be in place for operating the selected equipment for safe shutdown and operators should be trained in their use. It is not necessary to develop new procedures specifically for compliance with the USI A-46 program.

In Section 3.7, "Operations Department Review of SSEL," of GIP-2, SQUG also described three methods for accomplishing the operations department reviews of the SSEL against the plant operating procedures. Licensees were to decide which method or combination of methods were to be used for their plant-specific reviews. These methods included:

1. A "desk-top" review of applicable normal and emergency operating procedures.

2. Use of a simulator to model the expected transient.

3. Performing a limited control room and local in-plant walk-down of actions required by plant procedures.

The staff's evaluation of the SQUG approach for the identification and evaluation of the SSEL, including the use of operator actions, was provided in Section 11.3 of the staff's SSER on GIP-2. The evaluation concluded that the SQUG approach was acceptable.

The staff's review focused on verifying that the licensee had used one or more of the GIP-2 methods for conducting the operations department review of the SSEL and had considered aspects of human performance in determining what operator actions could be used to achieve and maintain safe shutdown (e.g., resetting relays and manual operation of plant equipment).

The licensee provided information that outlined the "desk-top" evaluation method used by the operations department to verify that existing normal, abnormal, and emergency operating procedures were adequate to mitigate the postulated transient and that operators could place and maintain the plant in a safe shutdown condition. The licensee determined that the systems and equipment selected for seismic review in the USI A-46 program are those for which normal, abnormal, and emergency operating procedures are available to bring the plant from a normal operating mode to a safe shutdown condition. The shutdown paths selected were reviewed by the Oconee Operations staff and, as necessary, by the Keowee hydroelectric station operations department. It was determined that the procedures would provide adequate guidance to the operators in response to a seismic event. The licensee provided assurance that ample time existed for operators to take the required actions to safely shut down the plant. This had been accomplished during validation of the pertinent plant operating procedures related to the licensees USAR, "Accident Analysis for the Loss of Offsite Power (LOOP)" transient which preceded the A-46 program review. The licensee stated that since these plant procedures had already been validated to ensure adequate time and resources are available for operators to respond to a the analyzed transients, it was not necessary to re-validate these procedures for the USI A-46 program.

The staff verified that the licensee had considered its operator training programs and verified that its training was sufficient to ensure that those actions specified in the procedures could be accomplished by the operating crews. The Operations department verified that all actions necessary to safely shut down the plant were included in existing normal, abnormal, and emergency operating procedures. The licensee verified that no additional operator actions, beyond those associated with the safe shutdown paths, must be performed to bring the plant from a normal operating mode to a safe shutdown condition.

In addition, the staff requested verification that the licensee had adequately evaluated potential challenges to operators, such as lost or diminished lighting, harsh environmental conditions, potential for damaged equipment interfering with the operators tasks, and the potential for placing an operator in unfamiliar or inhospitable surroundings. The licensee provided information to substantiate that potential challenges to the operator were explicitly reviewed as part of the USI A-46 validation effort.

In addition, the licensee explicitly evaluated the potential for local failure of architectural features and the potential for adverse spacial interactions in the vicinity of safe shutdown equipment, where local operator action may be required, as part of the GIP-2 process. As a result of the review, several potential control room interaction sources were identified associated with non-restrained equipment (e.g., suspended ceilings and lights, unanchored cabinets and miscellaneous stands, unrestrained computer equipment, and other miscellaneous desktop items and furniture). The licensee committed to resolve these outlier issues in accordance with their outlier resolution schedule by the end of INNAGE 73 (which coincides with the end of the Unit 1 Cycle 20 refueling outage currently scheduled for June 2, 2002). The licensee performed seismic interaction reviews which eliminated any concerns with the plant components and structures located in the immediate vicinity of the components that had to be manipulated. Therefore, the potential for physical barriers resulting from equipment or structural earthquake damage that could inhibit operator ability to access plant equipment was considered and eliminated as a potential barrier to successful operator performance.

The licensee has provided the staff with sufficient information to demonstrate conformance with the NRC-approved review methodology outlined in GIP-2, and the licensee's review approach is, therefore, acceptable for the resolution of the USI A-46 program at ONS.

2.9 Outlier Identification and Resolution

An outlier is defined as an item of equipment which does not comply with the GIP-2 screening guidelines.

A total of 1054 outlier items were identified as a result of USI A-46 program implementation at ONS. A total of 638 outlier items were identified to have affected 426 pieces of mechanical and electrical equipment. Of these, 62 were for class "0" equipment, 101 were for capacity versus demand, 210 were for B.S. caveats, 184 were for anchorage and 81 were for seismic interaction concerns. As stated in Section 8.1 of the summary report (References 12 and 14), 247 of these outlier items have been resolved. Descriptions of mechanical and electrical equipment outliers are provided in Tables 8-1 and 8-2 of the summary report, with the resolved outliers and their methods of resolution presented in Table 8-1, and the unresolved outliers and their proposed method of resolution presented in Table 8-2. In addition to the 638 outliers discussed above, DPC stated that: (1) the 68 identified tank and heat exchanger outliers were resolved, (2) of the 119 identified cable tray and conduit raceway support outliers, 49 were resolved, and (3) of the 229 essential relay outliers, 6 were resolved. The methods used and proposed to identify and to resolve outliers are consistent with the GIP-2 methodology and recommendations. The staff considers these methods acceptable for the resolution of USI A-46 at ONS.

In a letter dated June 30, 1998 (Reference 19), DPC advised the staff of the expected completion date for the resolution of all USI A-46 outliers. The letter states that the USI A-46 program completion letter will be submitted to the NRC within 120 days of the end of INNAGE 73, which is currently scheduled for June 2, 2002.

The review of the licensee's action regarding outliers indicates that many identified outliers have been resolved and the remainder are in the process of being resolved by analysis or corrective actions. Upon completion of the remaining outlier resolutions, the staff finds the licensee's actions acceptable for the resolution of USI A-46 at ONS.

3.0 SUMMARY OF MAJOR STAFF FINDINGS

Based on the information provided by the licensee, the staff found that the licensee's USI A-46 program has, in general, followed GIP-2 guidelines, and that no programmatic or significant deviations from the guidelines were made during the USI A-46 resolution process at ONS. As stated in Section 2.9, the licensee has committed to provide a USI A-46 program completion letter for ONS within 120 days of the end of INNAGE 73, which is currently scheduled for June 2, 2002 (Reference 19).

4.0 CONCLUSIONS

DPC's USI A-46 program for ONS was established in response to Supplement 1 to GL 87-02 and a 10 CFR 50.54(f) letter. In general, the licensee conducted the USI A-46 implementation in accordance with GIP-2 and the NRC staff SSER No. 2 on GIP-2. The licensee identified approximately 1054 outlier issues, many of which have been resolved. DPC committed to resolve all the remaining outlier issues within 120 days of the end of INNAGE 73, which is currently scheduled for June 2, 2002. The licensee's USI A-46 implementation program did not identify any instance where the operability of a particular system or component was called into question. The staff's review of the licensee's implementation program did not reveal any significant findings that would suggest inadequacy of the licensee's USI A-46 program in light of the GIP-2 guidelines. The staff, therefore, has concluded that the licensee's USI A-46 implementation program has, in general, met the purpose and intent of the criteria in GIP-2 and the staff's SSER No. 2 for the resolution of USI A-46. In addition, the staff has determined that the licensee's already completed actions will result in safety enhancements which, in certain aspects, are beyond the original licensing basis. As a result, the licensee's actions provide sufficient basis to close the USI A-46 review at the facility. The staff has also concluded that the licensee's implementation program to resolve USI A-46 at the facility has adequately addressed the purpose of the 10 CFR 50.54(f) request. Licensee activities related to the USI A-46 implementation may be subject to NRC inspection.

Regarding future use of GIP-2 in licensing activities, the licensee may revise its licensing basis in accordance with the guidance in Section I.2.3 of the staff's SSER No. 2 on SQUG/GIP-2, and the staff's letter to SQUG's Chairman, Neil Smith, on June 19, 1998 (Reference 20). It should be noted that the primary consideration in the staff's determination to permit the licensee to incorporate GIP-2 in the licensing basis, is the licensee's completion of all the identified outliers, in accordance with the GIP-2 requirements. Where plants have specific commitments in the licensing basis with respect to seismic qualification, these commitments should be carefully considered. The overall cumulative effect of the incorporation of the GIP-2 methodology, considered as a whole, should be assessed in making a determination under 10 CFR 50.59. An overall conclusion that no unresolved safety questions (USQ) is involved is acceptable so long as any changes in specific commitments in the licensing basis have been thoroughly evaluated in reaching the overall conclusion. If the overall cumulative assessment leads a licensee to conclude that a USQ is involved, incorporation of the GIP-2 methodology into the licensing basis would require the licensee to seek an amendment pursuant to 10 CFR 50.90.

5.0 REFERENCES

1. Regulatory Guide 1.100, "Seismic Qualification of Electric and Mechanical Equipment for Nuclear Power Plants," Revision 1, 1977.

2. IEEE Standard 344-1975, "IEEE Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations," January 31, 1975.

3. NRC SRP (NUREG-0800), Section 3.10, "Seismic and Dynamic Qualification of Mechanical and Electrical Equipment," Revision 2, July 1981.

4. NRC GL 87-02, "Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46," February 19, 1987.

5. "Generic Implementation Procedure (GIP) for Seismic Verification of Nuclear Power Plant Equipment, Revision 2, corrected February 14, 1992 (GIP-2)," Seismic Qualification Utility Group.

6. NRC "Supplement No. 1 to Generic Letter 87-02 Including Supplemental Safety Evaluation Report No. 2 on Seismic Qualification Utility Group's Generic Implementation Procedure, Revision 2, corrected February 14, 1992," May 22, 1992.

7. Letter from Duke Power to NRC dated September 21, 1992, "Oconee Units 1,2 & 3, Response to Supplement 1 to GL 87-02 on SQUG Resolution of USI A-46."

8. Letter from Duke Power to NRC dated January 15, 1993, " Clarification of the Oconee Nuclear Station Commitment to the GIP."

9. Letter from Duke Power to NRC dated March 3, 1993, " Clarification of the Oconee Nuclear station Commitment to the GIP."

10. Letter from NRC to Duke Power, dated November 19, 1992, "Evaluation of Oconee Units 1,2 & 3, 120-Day Response to Supplement 1 to GL 87-02.

11. Letter from NRC to Duke Power, dated April 5, 1993, "Evaluation of Oconee Units 1, 2 & 3, 120-Day Response to Supplement 1 to GL 87-02."

12. Letter from Duke Power to NRC dated December 30, 1996, "Partial Submittal of USI A-46 Report—Emergency Power Equipment Located at Keowee and in Switchyard," two volumes.

13. Letter from Duke Power to NRC dated December 15, 1997, "Submittal of Remaining Portion of USI A-46 — Equipment Seismic Adequacy Evaluation," five volumes.

14. Letter from Duke Power to NRC dated September 28, 1998, "SQUG Resolution of USI A-46," five volumes.

15. Letter from NRC to Duke Power dated February 18, 1998, "Request for Additional Information."

16. Letter from Duke Power to NRC dated May 14, 1999, "Response to Request for Additional Information."

17. Memorandum, B. W. Sheron, to A. C. Thadani, "Task Action Plan for Performing Plant-Specific Review of the Implementation of the Resolution for Unresolved Safety Issue (USI) A-46," dated July 26, 1994.

18. "Duke Power Company - Oconee Nuclear Station - Updated Final Safety Analysis Report (USAR), Updated 12/31/95."

19. Letter from Duke Power to NRC dated June 30, 1998, "SQUG Resolution of USI A-46 (Generic Letter 87-02) - Expected Completion of SQUG Outliers."

20. Letter from B. W. Sheron (NRC) to Neil Smith (SQUG), dated June 19, 1998.

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