April 17, 2007

Mr. Gordon Bischoff, Manager
Owners Group Program Management Office
Westinghouse Electric Company
P.O. Box 355
Pittsburgh, PA 15230-0355

SUBJECT: DRAFT SAFETY EVALUATION FOR TOPICAL REPORT WCAP-15622, "RISK-INFORMED EVALUATION OF EXTENSIONS TO AC ELECTRICAL POWER SYSTEM COMPLETION TIMES" (TAC NO. MB2257)

Dear Mr. Bischoff:

By letter dated June 15, 2001 (OG-01-039), as supplemented by letters dated November 27, 2002 (OG-02-052), and December 10, 2003 (OG-03-635), the Pressurized Water Reactor Owners Group (PWROG), formerly the Westinghouse Owners Group, submitted Topical Report (TR) WCAP-15622, Revision 0, "Risk-Informed Evaluation of Extensions to AC [Alternating Current] Electrical Power System Completion Times," to the U. S. Nuclear Regulatory Commission (NRC) staff for review. Approval of the TR was requested for referencing by licensees seeking relief from current Technical Specifications where the completion times (CTs) are not long enough to address inoperabilities or to perform preventative maintenance at power of AC electric power systems.

An initial draft safety evaluation (SE) was provided by the NRC to the PWROG by letter dated July 1, 2005, entitled "Draft Safety Evaluation for Topical Report WCAP-15622, Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times." The NRC staff received comments from the PWROG on September 27, 2005. The PWROG comments initiated additional evaluation and a revised draft safety evaluation. Enclosed for the PWROG's review and comment is a copy of the NRC staff's revised draft SE for the referenced TR.

Twenty working days are provided to you to comment on any factual errors or clarity concerns contained in the SE. The final SE will be issued after making any necessary changes and will be made publicly available. The NRC staff's disposition of your comments on the draft SE will be discussed in the final SE.

Based upon its review, the NRC staff concludes that the following proposed increases in CTs are not approved for generic implementation (referencing in license amendments) based upon the information provided in the TR: (1) 24 hours to 72 hours for an inoperable DG to confirm operability of the other DG; (2) 72 hours to 7 days for an inoperable DG to restore the inoperable DG; and (3) 2 hours to 24 hours for an inoperable vital AC bus to restore the inoperable bus. However, the NRC staff approves the WCAP-15622 risk-informed methodology in this TR for referencing in plant specific submittals. Furthermore, the NRC staff approves for generic implementation changes to the calculation of the second CTs for inoperable diesel generators (DG), inoperable AC electrical power distribution subsystems, inoperable vital AC buses, inoperable offsite circuits, and inoperable DC power distribution subsystems.

Individual plant submittals using the WCAP-15622 risk-informed methodology for CT extension will be reviewed by the NRC staff. However, because of the plant-specific nature of the methodology and analysis presented in the TR, the NRC staff finds that the plant-specific implementation of CT extensions would require licensees to evaluate compensating features and actions (including possible alternate CTs and alternate replacement power) such that the deterministic issues are addressed and Regulatory Guides (RGs) 1.174 and 1.177 guidelines are satisfied.

Sincerely,

/RA/

Stacey L. Rosenberg, Chief
Special Projects Branch
Division of Policy and Rulemaking
Office of Nuclear Reactor Regulation

Project No. 694

Enclosure: Draft SE

cc w/encl:
Mr. James A. Gresham, Manager
Regulatory Compliance and Plant Licensing
Westinghouse Electric Company
P.O. Box 355
Pittsburgh, PA 15230-0355

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Pittsburgh, PA 15230-0355

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DRAFT SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

TOPICAL REPORT WCAP-15622, REVISION 0, "RISK-INFORMED EVALUATION OF EXTENSIONS TO AC ELECTRICAL POWER SYSTEM COMPLETION TIMES"

PRESSURIZED WATER REACTOR OWNERS GROUP

PROJECT NO. 694

1.0 INTRODUCTION

Licensees for nuclear power plants have Technical Specifications (TSs) in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR), Section 50.36, "Technical specifications," that govern the operation of plants. These TSs have limiting conditions for operation (LCOs) that define which diesel generator (DG) and alternating current (AC) electrical power distribution systems (i.e., vital AC buses) must be operable and the applicable reactor modes of operation. If any of these required AC electric power systems are inoperable, the TSs specify the required actions to address the inoperability and the completion times (CTs). The U. S. Nuclear Regulatory Commission (NRC) improved standard TSs (ISTS) for Westinghouse plants is NUREG-1431, "Standard Technical Specifications for Westinghouse Plants," Revision 3, dated June 2004 (Reference 1). A description of the applicable systems and components is given in Appendix D of this safety evaluation (SE).

By letter dated June 15, 2001 (Reference 2), the Pressurized Water Reactor Owners Group (PWROG), formerly the Westinghouse Owners Group, submitted Topical Report (TR) WCAP-15622, Revision 0, "Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times," Non-Proprietary Class 3, to the NRC staff for review. The TR provides the PWROG's proposed technical justification for extending the ISTS CTs in TS 3.8.1, "AC Sources - Operating," Condition B, "One [required] DG inoperable," and TS 3.8.9, "Distribution Systems - Operating," Condition B, "One or more AC vital bus inoperable."

By letters dated November 27, 2002 (Reference 3), and December 10, 2003 (Reference 4), the PWROG supplemented the information in the TR by providing responses to the NRC staff's requests for additional information (RAIs). On July 1, 2005 (Reference 5), the NRC issued its initial draft SE entitled "Draft Safety Evaluation for Topical Report WCAP-15622, Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times." On September 27, 2005 (Reference 6), the NRC received comments from the PWROG relating to the draft SE that initiated additional NRC staff evaluation of the TR and revision of the draft SE.

Approval of the TR was requested for referencing by licensees seeking relief from current TSs where the CTs for inoperable AC electric power systems are not long enough to address inoperabilities or to perform preventative maintenance (where the equipment is declared inoperable until the equipment is returned to service). As stated in the TR, the proposed changes were intended to improve plant operational safety, provide a more consistent risk basis for the regulatory requirements, and reduce unnecessary regulatory burden, as follows:

- increase the flexibility in the scheduling and performance of preventive maintenance, enabling additional planned maintenance at power,
- provide additional time to perform related maintenance tasks,
- provide better resource allocation, in that online maintenance provides flexibility to focus dedicated resources on required or elective maintenance,
- limit unplanned plant shutdowns and potential requests for notices of enforcement discretion,
- improve the DG and other equipment availability during shutdown modes, and
- risk-inform the DG and AC electric power distribution system CTs.

2.0 REGULATORY REQUIREMENTS AND GUIDANCE

Regulatory Requirements:

General Design Criterion (GDC)-17, "Electric power systems," in Appendix A to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," requires that nuclear power plants have an onsite electric power system and an offsite electric power system to permit the functioning of structures, systems, and components (SSCs) important to safety. Refer to Appendix B, “Requirements in General Design Criterion (GDC)-17 and Recommendations in Regulatory Guide (RG) 1.9,” of this SE. The safety function of each system (assuming the other system is not functioning) is to provide sufficient capacity and capability to assure that (1) fuel design limits and design conditions of the reactor coolant boundary are not exceeded as a result of anticipated operational occurrences (AOOs) and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electric power supplies (including the batteries) and the onsite electric distribution system are required to have sufficient independence, redundancy, and testability to perform their safety functions, assuming a single failure. Electric power from the transmission network to the onsite electric distribution system is required to be supplied by two physically independent circuits designed and located so as to minimize the likelihood of their simultaneous failure. Each of these circuits are required to be designed to be available in sufficient time following a loss of all onsite AC power supplies and the other offsite electric power circuit, to assure that fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits is required to be available within a few seconds following an accident to assure that core cooling, containment integrity, and other vital safety functions are maintained. In addition, GDC-17 requires provisions to minimize the probability of losing electric power from the remaining electric power supplies as the result of loss of power from the unit, the offsite transmission network, or the onsite power supplies.

10 CFR 50.36 requires that the TSs for a plant be derived from the analyses and evaluations included in the plant’s Final Safety Analysis Report. An LCO is required to be established for each SSC that is part of the primary success path and which functions or actuates to mitigate a design-basis accident (DBA) or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier. LCOs specify minimum requirements for SSCs to ensure the safe operation of the plant.

- Included with LCOs are Surveillance Requirements (SRs) which provide requirements to assure that the necessary quality and performance of required systems and components are maintained and the LCOs are being met. When an LCO is not met, due to one condition such as either a component failure or maintenance outage, action is required within a specified time by the TSs to fix the condition by restoring required equipment to an operable condition. This specified time to take action is referred to as the CT. The specific Condition for why the LCO is not being met, the required actions for that Condition, and the CTs for these required actions are specified in the TSs.

- The CT is a temporary relaxation of operability for required equipment, which provides a limited time to fix components and return required equipment to an operable status. Establishing this limited time to fix components is based, primarily, on the reliability of remaining operable required equipment (during the short time period of a CT) being judged commensurate with reliability when all required equipment is operable.

TR WCAP-15622, Revision 0, references the term "allowed outage time" (AOT) as used in the standard TSs (STSs) which predate the ISTS in NUREG-1431. However, the LCO markups included in the TR use the ISTS term "CT." Recognizing the fact that NRC Inspection Manual, Part 9900, Technical Guidance, “Maintenance - Voluntary Entry Into Limited Conditions for Operations Action Statements to Perform Preventive Maintenance,” footnote 1, states that “[a]llowed outage time is a vernacular term for completion time,” the PWROG informed the NRC staff that it uses the term AOT interchangeably with the term CT in TR WCAP-15622, Revision 0. In terms of the evolution of TSs to STSs to the current ISTSs, the NRC staff uses only the term CT in this SE as it is intended in the ISTSs.

Applicable Regulatory Guidelines and Standards:

RG 1.9, "Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants," Revision 3, dated July 1993 (Reference 8), provides recommendations or guidelines for satisfying GDC-17. Included in the RG is the Institute of Electrical and Electronic Engineers (IEEE) Standard 387-1984, "IEEE Standard Criteria for Diesel Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations," which provides design criteria and qualification, and testing guidelines that, if followed, will help ensure that DGs meet performance requirements.

RG 1.93, "Availability of Electric Power Sources," dated December 1974 (Reference 9) provides guidance with respect to operating restrictions (i.e., CTs) if the number of available AC power sources is less than that required by the TS LCO. In particular, this guidance prescribes a maximum CT of 72 hours for an inoperable AC power source.

Chapter 19.0 of the NRC Standard Review Plan (SRP), NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants" (Reference 10), provides general guidance for evaluating the technical basis for proposed risk-informed changes. Chapter 16.1, "Risk-Informed Decisionmaking: Technical Specifications," of the SRP, which includes CT changes as part of risk-informed decisionmaking, provides more specific guidance related to risk-informed TS changes. Chapter 19.0 of the SRP states that a risk-informed application should be evaluated to ensure that the proposed changes meet the following key principles:

- The proposed change meets the current regulations, unless it explicitly relates to a requested exemption or rule change.

- The proposed change is consistent with the defense-in-depth philosophy.

- The proposed change maintains sufficient safety margins.

- The proposed change, if resulting in an increase in core damage frequency or risk, the increase(s) should be small and consistent with the intent of the Commission's Safety Goal Policy Statement.

- The impact of the proposed change should be monitored using performance measurement strategies.

RGs 1.174 and 1.177 (References 11 and 12) provide specific guidance and acceptance guidelines for assessing the nature and impact of licensing-basis changes, including proposed permanent TS changes in CTs, by considering engineering issues and applying risk insights. RG 1.177 identifies an acceptable 3-tiered risk-informed approach, which includes additional guidance specifically geared toward the assessment of proposed CT changes.

In addition, RG 1.177 outlines more specific methods and guidelines acceptable to the NRC staff for assessing risk-informed TS changes. Specifically, RG 1.177 provides recommendations for using risk information to evaluate changes to TS CTs and surveillance test intervals (STIs) with respect to the impact of the proposed change on the risk associated with plant operation. RG 1.177 also describes acceptable implementation strategies and performance monitoring plans to help ensure that the assumptions and analysis used to support the proposed TS changes will remain valid. Consistent with RG 1.174, risk-informed TS changes (including risk analysis techniques) are expected to meet a set of key principles. RG 1.177 includes the key principles of RG 1.174, as stated above, which also apply to TS changes.

The approach in TR WCAP-15622, Revision 0, is consistent with the NRC's approach for applying probabilistic risk assessment (PRA) to risk-informed plant-specific changes to the current licensing basis, as documented in RGs 1.174 and 1.177.

3.0 EVALUATION

3.1 Deterministic Evaluation of Proposed Changes to CTs

The NRC staff has reviewed the methodology for the proposed extensions of the CTs for the DGs and AC vital buses, as described in TR WCAP-15622, Revision 0. The proposed increases in CTs affect the LCO requirements of TS 3.8.1, and TS 3.8.9. Currently, TS 3.8.1 of the ISTS requires the restoration of an inoperable DG to operable status within 72 hours and confirmation that the operable DG(s) is/are not inoperable because of a common cause failure within 24 hours. In addition, TS 3.8.9 of the ISTS require that with one or more AC vital buses inoperable, the inoperable vital bus(es) must be restored to operable status within 2 hours.

3.1.1 LCO 3.8.1, Required Actions B.3.1 and B.3.2, DG Common Cause Failure Evaluation

- Increase the CT from 24 hours to 72 hours for an inoperable DG to confirm the operability of the other DG.

  — LCO 3.8.1, Condition B, "One [required] DG inoperable," to perform Required Action B.3.1, "Determine OPERABLE DG(s) is not inoperable due to common cause failure," or Required Action B.3.2, "Perform SR 3.8.1.2 for OPERABLE DG(s)"

In accordance with the ISTS, the Class IE AC electrical distribution system sources consist of the offsite power sources and the onsite standby power sources. According to GDC-17, the design of the AC electrical power system must provide sufficient capacity, capability, independence, redundancy, and testability to ensure an available source of power to engineered safety feature (ESF) systems. To this end, the onsite standby power sources for each ESF bus include a dedicated DG. The DG starts automatically on a safety injection signal or ESF degraded voltage, or loss of voltage signal.

Required Actions B.3.1 and B.3.2 provide an allowance to avoid testing of the operable DG. These Actions also require the licensee to demonstrate that, with one required DG inoperable, the remaining DG(s) are not inoperable because of a common cause. If it can be shown that the cause of the inoperable DG(s) does not exist for the operable DGs, then the surveillance test on the operable DG(s) does not have to be performed. If not, the performance of the surveillance test would then provide assurance that the remaining DG(s) continue to be operable. If the cause is found to exist for the other DG(s), then the DG(s) would also be declared inoperable upon discovery and Condition E of LCO 3.8.1 entered. Currently, completion of either Required Actions B.3.1 or B.3.2 is required within 24 hours.

The proposed CT extension is applicable to entry into Condition B of LCO 3.8.1 for DG unplanned corrective maintenance activities. While in the corrective action mode, if the root cause and its applicability to other DGs cannot be identified within 24 hours, the plant remains vulnerable to a potential blackout because of the uncertainty in the operability of other DG(s) without any other compensatory actions. The initial CT was based upon certain grid outage and frequency assumptions, see NUREG 6890 (Reference 13). However, recent industry experience with grid outages indicates that even though the outage frequency is lower, the duration is longer given that it takes more time for offsite power recovery (Refer to NRC Information Notice 2006-06). Therefore, to ensure that a defense-in-depth methodology is maintained during these extended DG outages, generically extending the CT from 24 hours to 72 hours for a licensee to demonstrate that the remaining DG(s) is/are not inoperable because of a common cause is unacceptable. Additional plant-specific evaluations and justifications would be required to support extending this CT.

3.1.2 LCO 3.8.1, Required Action B.4, DG Extended CTs

- Increase the CT from 72 hours to 7 days for an inoperable DG to restore the inoperable DG (the licensee for Comanche Peak Steam Electric Station (CPSES) stated in TR WCAP-15622, Revision 0, that it would propose 14 days in its plant-specific application and the 14 days is not addressed in this SE for an inoperable DG to restore the inoperable DG).

— LCO 3.8.1, Condition B, "One [required] DG inoperable," to perform Required Action B.4, "Restore [required] DG to OPERABLE status"

The TR stated that operating experience has shown that the DG CT is the most demanding part of the DG TSs and included examples of scenarios in which the present 72-hour CT provided inadequate time to complete certain repairs. The proposed 7-day CT for LCO 3.8.1, Required Action B.4, does not affect the adequacy of the offsite circuits or the remaining operable DG(s) to supply power.

Recent industry experience indicates a reduced frequency for loss of power events but an increased duration for recovering from a loss-of-offsite power (LOOP). Extending the CT for a DG outage from 72 hours to 7 days (or potentially more for some sites) without suitable replacement power for a train of safety bus is unacceptable from a deterministic standpoint in light of potentially fewer but increased duration grid outages. TR WCAP-15622, Revision 0, does not provide the necessary deterministic justification to support extending the CT to 7 days (or potentially more for some sites) without suitable replacement power. Therefore, the proposed request for generically extending CT for LCO 3.8.1 to restore an inoperable DG is not acceptable to the NRC staff. Additional plant-specific evaluations and justifications would be required to support extending this CT.

3.1.3 LCO 3.8.9, Required Action B.1, Restore AC Vital Bus to Operable Status

- Increase the CT from 2 hours to 24 hours for an inoperable vital AC bus to restore the inoperable bus.

  — LCO 3.8.9, Condition B, "One or more AC vital buses inoperable," to perform Required Action B.1, "Restore AC vital bus subsystems(s) to OPERABLE status"

As stated in the Bases for TS 3.8.1 of the ISTS, the vital AC buses are arranged in two load groups per train. The vital AC buses are normally fed from inverters. The voltage-regulating transformers powered from the same train as the inverters generally supply the alternate power. The loads fed from the vital AC buses generally consist of nuclear instrumentation, instrumentation/control power, reactor protection system racks, the solid-state protection system, and ESF actuation system slave, master relays, and instrument power supplies, as well as others.

With one or more AC sources inoperable, the plant is much more vulnerable to a loss of all non-interruptible power. The proposed CT of 24 hours only applies to the first inoperable vital AC bus. TR WCAP-15622, Revision 0, also states that with one vital AC bus inoperable, the remaining operable vital AC buses can support the minimum functions required to shut down the unit. All instrumentation logic systems for reactor protection and emergency core cooling systems are not identically designed to perform all required operations with one less vital AC bus. Backup sources of power not supported through a battery system could have interruptions that challenge the logic system and result in unanticipated results. The process signals such as refueling water storage level, containment high radiation, etc., would need a reliable power source for mitigating the effects of a potential accident. Therefore, additional plant-specific evaluations and justifications would be required to extend the CT of additional vital AC buses beyond the current CT of 2 hours.

3.2 Risk-Informed Evaluation of Proposed Changes to CTs

An evaluation of the TR WCAP-15622, Revision 0, PRA methodology is given in Appendix A to this SE. Based on the review of its proposed changes, the NRC staff finds that the methodology presented in TR WCAP-15622, Revision 0, is consistent with the guidelines stated in RG 1.174, RG 1.177, and Chapter 16.1 and 19.0 of NUREG-0800. However, the NRC staff also finds that, for the proposed plants, the impact on plant risk might be unacceptable in comparison to the NRC acceptance guidelines. For example, the NRC staff found the proposed CT for LCO 3.8.1 (Required Action B.4, 72 hours to 7 days) typically resulted in incremental conditional core damage probability (ICCDP) values greater than the RG 1.177 acceptance guidelines. In addition, for one plant, the change in core damage frequency (ΔCDF) did not meet the guidance for a small change. For three of the five plants that evaluated a revision to LCO 3.8.1 (Required Actions B.3.1 or B.3.2, 24 to 72 hours) and for four of the five plants that evaluated a revision to LCO 3.8.9 (Required Action B.1, 2 to 24 hours), the ICCDP values for repair also exceeded the RG 1.177 acceptance guidelines. Estimates for the change in large early release frequency (ΔLERF) and the incremental conditional large early release probability (ICLERP) were screened out of the TR WCAP-15622, Revision 0, analysis based on the assumed limited system CT impact on releases from containment, and therefore, were not provided in TR WCAP-15622, Revision 0.

In a response to an RAI, the PWROG provided revised risk estimates for ΔCDF, ΔLERF, ICCDP, and ICLERP for some of the TR WCAP-15622, Revision 0, plants. The revised estimates reflected the use of compensatory measures, revised CTs, and revised analysis assumptions. The NRC staff found that these revised estimates were typically within the acceptance guidelines of RGs 1.174 and 1.177; however, because of the plant-specific nature of the methodology and analysis presented in TR WCAP-15622, Revision 0, the NRC staff finds that the plant-specific implementation of the proposed changes in CT will require licensees to evaluate compensating features and actions (including possible revision to the proposed CTs) to show that the RGs 1.174 and 1.177 guidelines remain satisfied. Licensees must also evaluate changes in ΔCDF, ΔLERF, ICCDP and ICLERP on a plant-specific basis.

Therefore, the NRC staff concludes that the TS changes proposed by TR WCAP-15622, Revision 0, to extend the CTs for an inoperable DG or vital AC bus, do not always meet all the acceptance guidelines in RGs 1.174 and 1.177. Based on that fact, the NRC staff further concludes that it has not been demonstrated that the specific changes proposed by the TR will be acceptable. Additional plant-specific evaluations and justifications would be required to support extending these CTs.

3.2.1 LCO 3.8.1, Required Actions B.3.1 and B.3.2, DG Common Cause Failure Evaluation

TR WCAP-15622, Revision 0, proposes and provides justification for increasing the current CT in the ISTS to complete a DG common cause evaluation for an inoperable DG from 24 hours to 72 hours, based on a risk-informed approach.

3.2.1.1 Background

In the ISTS, when one DG is inoperable, the TSs require that the operability of the remaining offsite and onsite AC power sources must be verified. For the offsite system, operability is verified within 1 hour and every 8 hours thereafter when one DG is inoperable. For the onsite system, operability is verified by starting the remaining operable DG(s) within 24 hours to be certain that the operable DGs are not inoperable due to a common cause failure. These additional verifications are considered necessary by the NRC staff to provide assurance that the minimum required safety systems are supported by the remaining onsite AC sources when one DG is inoperable.

In the ISTS, the TS requirements are that the following changes (or options) to the above verifications also provide assurance that the minimum required safety systems are supported by the remaining AC sources when one DG is inoperable. For the offsite system, operability is still verified within 1 hour and every 8 hours thereafter. For the onsite system, operability is verified by starting the remaining operable DG(s) within 24 hours. However, as an alternative to starting the DG, operability can be verified by reaching a no-common-cause finding between the inoperable DG and the remaining operable DG(s) within 24 hours. The DG start and load test (required to be performed every 31 days according to the TS) and the common cause evaluation finding that there is no similar failure to the inoperable DG provide assurance that the minimum required safety systems are supported by the remaining AC sources and safety systems will be capable of performing their required safety function when needed when one DG is inoperable.

3.2.1.2 Evaluation

The NRC staff is concerned that risk informing the CT for the common cause evaluation is not consistent with the intent of the TS requirements or assumptions. The current 24-hour CT for the common cause evaluation for the remaining operable DG(s) (required by LCO 3.8.1, Required Action B.3.1) provides a CT allowance to avoid testing of operable DG(s) by providing a reasonable time to perform the evaluation and still meet the intent of the RG 1.93 regulatory position for "immediate verification" of the availability and integrity of the remaining sources. If the common cause evaluation (required by Required Action B.3.1) concludes that the cause of the inoperable DG does not exist for the operable DG(s) then surveillance testing of the operable DG(s) does not have to be performed. The 24-hour common cause failure evaluation is considered to meet the regulatory position of "immediate verification" while providing a means to limit DG surveillance testing. In addition, the 24-hour CT is considered reasonable to confirm that the operable DG(s) is not affected by the same failure as the inoperable DG. The DG(s) can, therefore, be considered to have the necessary reliability (NUREG-1431/Generic Letter 84-15) to perform its safety function when needed.

RG 1.93 discusses the situation when the available AC power sources are one less than the LCO. This degradation level as described by RG 1.93 means that one of the required offsite or onsite AC sources is not available. The RG states that, for this condition (which includes one required DG inoperable), operation can safely continue if the availability of the remaining sources is verified. However, a time limit (on the CT) is warranted due to the LCO entry. The regulatory position of RG 1.93 also states that continued power operation may continue but be contingent on: (a) an immediate verification of the availability and integrity of the remaining sources, (b) reevaluation of the availability of the remaining DG(s) at time intervals not to exceed 8 hours, (c) verification that the required maintenance activities do not further degrade the power system or in any way jeopardize plant safety, and (d) compliance with the additional conditions stipulated for each degradation level.

In addition, NUREG/CR-5460, “A Cause-Defense Approach to the Understanding and Analysis of Common Cause Failures” establishes a set of defensive tactics to decrease the likelihood of component or system unavailability. Among these are monitoring, surveillance testing, and inspection such that failures from any detectable cause are not allowed to accumulate, including tests performed on redundant components in response to observed failures. If the inoperable DG is restored to operable status prior to completing the common cause evaluation, the plant will continue to evaluate the common cause possibility, but the evaluation would be done under the plant corrective action program.

While in the corrective action mode, if the root cause and its applicability to other DGs cannot be identified within 24 hours, the plant remains vulnerable to a potential blackout because of the uncertainty in the operability of other DG(s). Recent industry experience indicates a reduced frequency on loss of power events but an increased duration for recovering from a LOOP. Based on this information, the status of the operable DG(s) would be unknown until the common cause evaluation is completed under the corrective action program.

Although the risk analysis provided by TR WCAP-15622, Revision 0, indicates that the acceptance guidance of RGs 1.174 and 1.177 may be met for some plants, the NRC staff finds that the extension of the 24-hour CT for common cause evaluation of the operable DG(s) presents additional uncertainty and that TR WCAP-15622, Revision 0, is not consistent with RG 1.93 regulatory positions and NRC staff guidance. Therefore, the extension is not justified by the evaluation provided in TR WCAP-15622, Revision 0, and should remain at 24 hours. Additional plant-specific evaluations and justifications would be required to support extending this CT.

3.2.2 LCO 3.8.1, Required Action B.4, DG Extended CTs

The TR WCAP-15622, Revision 0, methodology proposes and provides justification for increasing the current CT of 72 hours for an inoperable DG. None of the regulatory requirements mentioned in Section 2.0 of this SE prevent the CT for an inoperable DG from being extended from the current 72 hours in the TSs. However, extending the outage time to 7 days, increases the risk of losing power to the safety trains during a potential LOOP. Recent industry experience indicate that the number of loss of power events have been reduced but the recovery time from a loss of off site power has significantly increased resulting in an increased vulnerability for a safety train with the extended CT. A plant specific evaluation will be required to ensure that acceptable replacement power is available.

3.2.2.1 Evaluation

Appendix D of TR WCAP-15622, Revision 0, outlines specific analysis guidance to licensees concerning LCO 3.8.1, Required Action B.4, to increase the CT from 72 hours to 7 days. Appendix D supplements Appendix C of the TR with more detail and guidance specific to the TS change request. The additional guidance includes DG events, impact on the PRA model, DG modeling for LOOP events, and modifying the PRA with an extended DG CT. This TR appendix evaluates RG 1.174 and 1.177 acceptance guidelines with data collection information specified for review and presentation. It also includes an RAI, which is based on the NRC staff RAI to another Owners Group for that groups' DG CT extension request. The additional information in Appendix D of TR WCAP-15622, Revision 0, that should be included in the plant-specific submittals is listed in Appendix E of this SE.

Appendix D of TR WCAP-15622, Revision 0, also recommends that realistic test and maintenance times be used for the extended CT and states that this is consistent with RG 1.177. However, RG 1.177 references the use of mean outage values when calculating the change in average CDF, but for ICCDP or ICLERP it is assumed that the full CT is used. In addition, for a DG in repair, the TR states that the common cause factor (e.g., the beta factor for two DGs) should be used for the available DG when estimating ICCDP for a DG in repair. The calculation of ΔLERF and ICLERP is stated to not be required for the DG CT extension as outlined in the TR. The NRC staff does not generically accept this TR position and will require, on a plant-specific basis, confirmation of conformance to the ΔLERF and ICLERP acceptance guidelines.

The ΔCDF for most of the participating plants was within the RG 1.174 acceptance guidelines for a small change in CDF of 1.0E-6/year. However, the ICCDP values for either a maintenance or repair DG CT of 7 days are all greater than the RG 1.177 acceptance guideline of 5.0E-7 and, therefore, do not meet the guidelines of RG 1.177. The results can vary significantly between plants, even those of similar design, based on individual plant characteristics, modeling assumptions, or vulnerabilities. Also note that TR WCAP-15622, Revision 0, does not provide the impact of internal flooding or external event risks. Differences in AC/DC electrical systems, alternate AC sources, DG reliability estimates, initiating event frequencies, and RCP- seal-LOCA models also contribute to the differences in plant results. Therefore, the allowances for the proposed 7-day DG CT may not be acceptable for plant-specific applications of the TR. See the discussion on the RCP-seal-LOCA models in Appendix C of this SE. It is expected that for a plant-specific DG CT extension submittal founded on TR WCAP-15622, Revision 0, a licensee will include plant-specific documentation on the RCP seal model employed and its conformance to NRC SE conditions for referencing TR WCAP-15603, Revision 1-A (Reference 14).

For shutdown risk, the evaluation is qualitative, in that most plants do not have a detailed shutdown risk model. The refueling outage duration and DG maintenance scheduling strongly influence the risk averted during shutdown (i.e., the various stages of an outage have different risk impacts). For example, the contribution to plant risk with respect to DG maintenance during the early stages of an outage with high decay heat, limited coolant inventory, and only electric pumps available is sensitive to DG unavailability. However, the risk impact can decrease substantially when maintenance is conducted during the later stages of an outage (e.g., during refueling). When DG maintenance is performed earlier in the outage, risk is higher and comparable to power operation (see NUREG/CR-5994, “Emergency Diesel Generator Maintenance and Failure Unavailability and Their Risk Impacts,” issued November 1994). Generally, taking an individual DG out for maintenance results in an increase in ICCDP of about an order of magnitude; but, as shown above, plant CDF is less sensitive to a DG in maintenance (see NUREG/CR-5994).

TR WCAP-15622, Revision 0, provided an evaluation based on the CPSES shutdown model and stated that performing a DG maintenance at power (assuming a 14-day CT) resulted in an ICCDP that was significantly smaller than if the maintenance had been performed during shutdown. The NRC staff disagreed with the TR approach because the PWROG performed the comparison by essentially summing the risk impact of various stages of the outage. Based on the analysis, the NRC staff determined that the performance of DG maintenance at power is essentially risk neutral with consideration given to maintenance scheduling at shutdown. With respect to performing DG maintenance at the beginning of an outage, as stated in the TR, performing DG maintenance online can provide a risk benefit, but this benefit is a result of reduced outage duration and DG maintenance scheduling by the licensee (i.e., higher risk configuration during shutdown). Therefore, with respect to the proposed 7-day DG CT, the shutdown risk averted may provide a qualitative risk benefit, but would not be credited in the risk evaluation presented in the plant-specific application per TR WCAP-15622, Revision 0.

These differences dictate that for a DG CT extension request, each licensee must submit a plant-specific analysis with regard to Tier 1, Tier 2, and Tier 3, as outlined in this SE and Sections 8.5 and 8.6 of TR WCAP-15622, Revision 0. Additionally, estimates of ΔLERF, ICLERP, external event risk, and cumulative risk, in accordance with the guidelines of RGs 1.174 and 1.177 are required for a plant-specific submittal.

3.2.2.2 Conclusion

Based on the PRA review of the change and the evaluation of the TR PRA methodology in Section 3.2 of this SE, the NRC staff concludes that the TS changes proposed in TR WCAP-15622, Revision 0, to extend DG CTs do not always meet all the acceptance guidelines in RGs 1.174 and 1.177. Therefore, it has not been demonstrated that the specific changes proposed by the TR are acceptable for generic implementation. Additional plant-specific evaluations and justifications would be required to support extending this CT.

3.2.3 LCO 3.8.9, Required Action B.1, Restore AC Vital Bus to Operable Status

The TR WCAP-15622, Revision 0, methodology proposes and provides justification for increasing the current CT of 2 hours for an inoperable AC vital bus. The methodology is based on a risk-informed approach.

3.2.3.1 Background

A typical onsite system design includes: (a) two independent and redundant AC system divisions (or trains) each with its associated onsite AC standby power supply, load group (or distribution subsystem), loss of power instrumentation, and automatic load sequencer; (b) four independent and redundant DC system divisions, each with its associated battery and battery charger power supplies and load group; and (c) four independent and redundant vital AC system divisions, each with its associated inverter AC vital power supply and load group (or vital AC bus). In accordance with the STS and ISTS, each vital AC bus is required to be energized from its associated inverter power supply, and the inverter power supply is required to be energized from the DC system power supply (through the DC load group) associated with the same DC and vital AC system division. When there is a loss of AC power, the vital AC bus (as part of the licensing bases) is expected to remain energized from the DC system battery power supply through the inverter.

With one AC vital bus not energized from its associated inverter or with the inverter not connected to its associated DC bus, the ISTS (through a TS required action) allows the AC vital bus to be re-energized (a) within 2 hours from an AC source that does not have a backup source of AC power from the DC system battery through an inverter and (b) within 24 hours from its associated inverter connected to its associated DC bus. The ISTS includes a CT of 2 hours (which is proposed in TR WCAP-15622, Revision 0, to be changed to 24 hours) to restore the AC vital bus to operable status. The bases for the ISTS state that the AC vital bus can be restored to operable status by powering the bus from an AC source that does not have a backup source of AC power from the DC system battery through an inverter. The STS, based on the definition of operability, requires the AC vital bus to be powered from an AC source that has a backup source of AC power to be considered operable. Operability of the AC vital bus when energized from an AC source that does not have a backup source of AC power from the DC system battery through an inverter is a change (based on the change to the definition of operability) from the STS to the ISTS, and could be a change to a plant-specific licensing basis. The impact on regulatory requirements should be addressed as part of the plant-specific evaluation for increasing the current CT of 2 hours if the plant TSs are based on the STS (Condition C of Section 4.0 of this SE).

3.2.3.2 Evaluation

Appendix F of TR WCAP-15622, Revision 0, provides specific analysis guidance to licensees concerning LCO 3.8.9, Required Action B.1. Appendix F gives additional detail and guidance regarding a specific TS change to increase the CT time from 2 hours to 24 hours. It evaluates RGs 1.174 and 1.177 acceptance guidelines with data collection information specified for PWROG review and presentation. Appendix F credits both sources of power to the vital AC buses (i.e., inverter and transformer) unless blackout events require credit only for the inverters. The appendix selects a mission time of 24 hours unless specific events use other mission times. The TR stated that no test activity that causes the unavailability of a component for the vital AC power supply will be performed at power. The TR assumed that the vital AC bus is OPERABLE when supplied from the alternate source, which is consistent with the ISTS.

Based on the submitted plant results, the proposed 24-hour loss of vital AC bus CT has a small impact on CDF but the estimates for ICCDP (in repair) typically exceed the acceptance guidelines of RG 1.177. V. C. Summer Nuclear Station (Summer) also does not meet the acceptance guidance for ICCDP (in maintenance). In addition, estimates for ΔLERF and ICLERP, vital AC bus repairs assumed per year, external events, and cumulative risk are required for a plant-specific submittal in accordance with the guidelines of RGs 1.174 and 1.177. The NRC will also require supplemental Tier 1, Tier 2, and Tier 3 evaluations on a plant-specific basis consistent with the guidance given in Sections 8.5 and 8.6 of TR WCAP-15622, Revision 0 (Item 1 of Section 4.0 of this SE).

3.2.3.3 Conclusion

Based on its review of the proposed increase in the CT for an inoperable AC bus, the NRC staff concludes that the proposed change meets the requirements of GDC-17 subject to the resolution of plant-specific safety issues involving whether the AC vital bus can be restored to operable status by powering the bus from an AC source that does not have a backup source of AC power from the DC system battery through an inverter. Operability of the AC vital bus when energized from an AC source that does not have a backup source of AC power from the DC system battery through an inverter may be a change to a plant licensing basis.

With one or more AC sources inoperable, the plant is much more vulnerable to a loss of all non-interruptible power. The proposed CT of 24 hours only applies to the first inoperable vital AC bus. TR WCAP-15622, Revision 0, also states that with one vital AC bus inoperable, the remaining operable vital AC buses can support the minimum functions required to shut down the unit. All instrumentation logic systems for reactor protection and ECCSs are not identically designed to perform all required operations with one less vital AC bus. Any backup source of power not supported through a battery system could have interruptions that could challenge the logic system and result in unanticipated results.

Based on the PRA review of the change and the evaluation of the TR PRA methodology in Section 3.2 of this SE, the NRC staff concludes that the TS changes proposed by TR WCAP-15622, Revision 0, to extend DG and vital AC bus CTs do not always meet all the acceptance guidelines in RGs 1.174 and 1.177. Therefore, it has been demonstrated that the specific changes proposed by the TR will not be acceptable for generic implementation. Additional plant-specific evaluations and justifications would be required to support extending this CT.

3.3 Second CTs for an Inoperable DG and Vital AC Bus (TS 3.8.1, Required Actions A.3 and B.4, and TS 3.8.9, Required Actions A.1, B.1, and C.1)

CTs (See ISTS Section 1.3, "Completion Times,") are the amount of time allowed in the ISTSs for completing a Required Action and the "time zero" for the CT is normally the time of discovery of an abnormal situation, such as inoperable equipment or a variable not within limits, that requires entering an Action Condition for an LCO in the TSs, unless otherwise specified. If situations are discovered that require entry into more than one Action Condition, the Required Actions for each Condition must be performed within the associated CT. To avoid indefinitely entering and exiting multiple Conditions without restoring the system to meet the LCO, a second CT was established (See ISTS Example 1.3-3) to prevent indefinite continued operation while not meeting the LCO.

This second CT allows for an exception to the normal "time zero" for beginning a CT, in that the "time zero" for the second CT is the time the LCO was initially not met, instead of when the associated Action Condition was entered. Because this second CT is based on the combination of CTs for multiple condition entries, the second CT is deterministic in nature which is consistent with the previous NRC staff reviews related to proposed extensions of DG CTs.

The NRC staff concludes that the algebraic sum of: (1) the CTs for an inoperable DG (TS 3.8.1) or an inoperable vital AC bus (TS 3.8.9), and (2) the CT for an inoperable offsite circuit (TS 3.8.1) or an inoperable DC bus (TS 3.8.9) are acceptable for determining the second CTs. Acceptable TS Bases statements for these second CTs are addressed in Appendix F of this SE.

3.4. Implied Extension for CT for LOOP Instrumentation (TS 3.3.5, Required Action C.1)

The typical electric system design includes LOOP instrumentation and automatic load sequencer support systems associated with each AC system division. The primary function of loss of power instrumentation is to assure the independence (or no common cause failure) between offsite and onsite systems.

ISTS LCO 3.3.5, "Loss of [Offsite] Power (LOOP) Diesel Generator (DG) Start Instrumentation," addresses the inoperable LOOP DG start instrumentation. In Condition C for ISTS LCO 3.3.5, where the required action and associated CTs are not being met for the inoperable LOOP instrumentation, the required action is for the licensee to declare the associated DG inoperable and enter the applicable condition(s) and required actions for that DG in ISTS 3.8.1, Condition B. Because TR WCAP-15622, Revision 0, proposes to increase the 72-hour CT for an inoperable DG in ISTS 3.8.1, Condition B, the TR is, in effect, also proposing to extend the CT for inoperable LOOP DG start instrumentation.

Because TR WCAP-15622, Revision 0, did not address an extended CT for inoperable LOOP DG start instrumentation, the NRC staff did not consider such an extended CT. On the basis that the NRC staff did not approve extending the CT for restoring AC vital buses to operable status without additional plant-specific evaluations and justification, licensees requesting an increase in the CT for restoring an AC vital bus must also consider the potential for extending the CT for inoperable LOOP DG start instrumentation in its submittal.

3.5 Summary of NRC Review

In summary, the NRC staff has found the following:

- The Tier 1 PRA capability and insights in TR WCAP-15622, Revision 0, are the plant-specific Tier 1 results that were submitted for the plants identified in Section A.1 of Appendix A of this SE and compiled in the TR for the plants. Because the TS changes proposed in TR WCAP-15622, Revision 0, for an inoperable DG or vital AC bus that were based on these Tier 1 results do not meet all the acceptance guidelines in RGs 1.174 and 1.177, the NRC staff concludes that the TR has not demonstrated that the proposed TS changes are acceptable without consideration of plant-specific Tier 2 and Tier 3 results. The additional plant-specific information identified in the conditions listed in Section 4.0 of this SE is needed in plant specific submittals.

- The proposed extension of the CT, from 24 hours to 72 hours, for an inoperable DG to either complete the common cause evaluation or perform SR 3.8.1.2 for the operable DGs is not deterministically supported by the TR. Additional plant-specific evaluations and justifications would be required to support extending this CT.

- Information needed for plant-specific submittals is discussed in Section 4.0 of this SE. This includes certain information that was identified in the responses to the NRC staff's RAIs for its review of TR WCAP-15622, Revision 0.

- The TR did not examine the sensitivity of each plant to the model used by the respective licensees for the reactor coolant pump (RCP) seal during a seal loss-of-coolant accident (LOCA). Licensees must document the RCP seal model used in any plant-specific submittal based on TR WCAP-15622, Revision 0, as discussed in Appendix C of this SE.

- The proposed extension of the CT to restore an inoperable DG implies a similar extension in CT for a DG made inoperable because the LOOP start instrumentation is inoperable. However, because this CT extension was not proposed in TR WCAP-15622, Revision 0, it was not considered part of the scope of the NRC staff review, therefore, in the plant-specific applications, licensees must either: (1) provide the impact on the DG CT and a basis for extending this DG CT for inoperable LOOP DG start instrumentation or (2) propose TS changes to separate the CT in the plant TSs for ISTS LCO 3.3.5, Condition C from the CTs in ISTS LCO 3.8.1, Condition B, as discussed in Section 3.4 of this SE.

- The extended CT for an inoperable DG is in part to allow sufficient time for more planned online DG maintenance because the DG is inoperable during the maintenance. The initial CTs established in the TSs allow for a temporary loss of defense-in-depth so that the operators can either restore the DGs to operable status or safely shut down the reactor. This CT was based upon certain grid outage and frequency assumptions, see NUREG 6890. However, recent industry experience with grid outages indicates that even though the outage frequency is lower, the duration is longer given that it takes more time for offsite power recovery (Refer to NRC Information Notice 2006-06). Therefore, to ensure that a defense-in-depth methodology is maintained during these extended DG outages, the NRC staff finds that generically extending DG outages without suitable replacement power alternatives would be unacceptable. Additional plant-specific evaluations and justifications would be required to support extending this CT.

- The proposed extension to the CT to restore an inoperable vital AC bus may change the plant-specific licensing basis if the plant TSs are based on the ISTS because the proposed CT extension implies the vital AC bus could be OPERABLE without a backup source of AC power from the direct current (DC) system battery through an inverter. This was not reviewed by the NRC staff as part of its review of TR WCAP-15622, Revision 0, and licensees need to address this in plant-specific applications.

4.0 ADDITIONAL INFORMATION NEEDED IN PLANT-SPECIFIC SUBMITTALS

In general, the NRC staff does not approve the extended CTs requested within TR WCAP-15622, Revision 0 for generic implementation. However, the NRC staff will consider requests for extended CTs based on individual, plant-specific submittals with updated plant-specific data, as applicable.

The following information is needed to supplement plant-specific applications proposing an extended DG or vital AC bus CT:

A. Because LCO 3.8.9, Condition B, of TR WCAP-15622, Revision 0, evaluates increasing the CT for only one inoperable vital AC bus, the proposed CT of 24 hours is only applicable to the first inoperable vital AC bus.

B. In proposing compensatory measures to support plant-specific submittals (e.g., for reduced LOOP event frequency), licensees must discuss in its submittal the incorporation of these compensatory measures into plant operating practices and procedures, and the plant PRA model. The discussion must include the modeling of the compensatory measures, human error probabilities for operator action, and the contribution of the proposed compensatory measures to CT risk.

C. The ISTS includes a CT of 2 hours (proposed to be changed to 24 hours) to restore the AC vital bus to operable status. The ISTS Bases for TS 3.8.9 states that the AC vital bus can be restored to operable status by powering the bus from an AC source that does not have a backup source of AC power from the DC system battery through an inverter. Operability of the AC vital bus when energized from an AC source that does not have a backup source of AC power from the DC system battery through an inverter may be a change to the plant licensing bases if the plant TSs are based on the ISTS. The evaluation of this change for its impact on regulatory requirements must be addressed as part of the plant-specific evaluation for increasing the current CT of 2 hours.

D. With respect to the proposed 7-day DG CT, the shutdown risk averted may provide a qualitative risk benefit, but it should not be credited in the risk evaluation presented by licensees in their plant-specific applications

Also to be acceptable, plant-specific submittals must provide additional information in the following areas (specific questions are in Appendix E to this SE) in proposing an extended CT for an inoperable DG or vital AC bus:

1. Appendix D of TR WCAP-15622, Revision 0.

2. Plant PRA Quality.

3. Tier 1, Tier 2, and Tier 3 Information.

4. Associated Extended CT for LOOP DG Start Instrumentation.

5. Commitments Needed from Licensees.

6. Alternative Power Sources and Cross-Connecting Safety Buses.

7. RCP-Seal-LOCA Model.

8. Post-Maintenance Testing Following Online Maintenance.

9. Maintenance Rule and Station Blackout.

5.0 CONCLUSIONS

Based upon its review, the NRC staff concludes that the following proposed increases in CTs are not approved for generic implementation based upon the information provided in the TR: (1) 24 hours to 72 hours for an inoperable DG to confirm operability of the other DG; (2) 72 hours to 7 days for an inoperable DG to restore the inoperable DG; and (3) 2 hours to 24 hours for an inoperable vital AC bus to restore the inoperable bus. However, the NRC staff approves the WCAP-15622 methodology for referencing in plant specific submittals. Furthermore, the NRC staff approves for generic implementation the changes to the calculation of the second CTs for inoperable diesel generators (DG), inoperable AC electrical power distribution subsystems, inoperable vital AC buses, inoperable offsite circuits, and inoperable DC power distribution subsystems.

In plant-specific submittals that follow the WCAP-15622 methodology, the NRC staff will consider extending either part or all of the above CTs. This extension may be based on updated, individual, plant-specific data, with further compensatory measures and/or justification in the submittals.

6.0 REFERENCES

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11. U.S. Nuclear Regulatory Commission, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Regulatory Guide 1.174, Revision 1, November 2002, ADAMS Accession No. ML023240437.

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14. Westinghouse Owners Group, “WOG 2000 Reactor Coolant Pump Seal Leakage Model for Westinghouse PWRs,” WCAP-15603, Rev. 1-A (Non-Proprietary), June 2003, ADAMS Accession No. ML032040132 .

Attachments: Appendix A, "Probabilistic Risk Assessment (PRA) Methodology of TR WCAP-15622, Revision 0"
Appendix B, "Requirements in General Design Criterion (GDC)-17 and Recommendations in Regulatory Guide (RG) 1.9"
Appendix C, "Reactor Coolant Pump (RCP) Seal Model"
Appendix D,"Description of Applicable Electrical Systems and Components"
Appendix E, "Additional Information Needed for Plant-Specific Applications"
Appendix F, "Second Completion Time (CT) for an Inoperable Diesel Generator (DG) or Vital Alternating Current (AC) Bus"

Principal Contributors: Cliff Doutt
Tom Koshy

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APPENDIX A

PROBABILISTIC RISK ASSESSMENT (PRA) METHODOLOGY OF TR WCAP-15622, REVISION 0

A.1 PRA Approach Taken in TR WCAP-15622, Revision 0

The approach used in TR WCAP-15622, Revision 0, is consistent with the NRC's approach for using PRA in risk-informed decisions on plant-specific changes to the current licensing basis for nuclear power plants as discussed in RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis" and RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications." The approach addresses the impact on defense-in-depth, safety margins, and plant operational risk. The risk evaluation considers the three-tier approach presented in RG 1.177. Tier 1, PRA capability and insights, assesses the impact of the proposed completion times (CTs) on core damage frequency (CDF), and incremental conditional core damage probability (ICCDP), large early release frequency (LERF), and incremental conditional large early release probability (ICLERP) and is addressed in TR WCAP-15622, Revision 0.

Tier 2, avoidance of risk-significant configurations (i.e., risk-significant plant operating configurations) and Tier 3, risk-informed configuration risk management, are not addressed in TR WCAP-15622, Revision 0. Tier 2 and Tier 3 will be addressed in the plant-specific application when the CT changes are implemented by a specific licensee on a specific plant.

In the TR approach, the Pressurized Water Reactor Owners Group (PWROG) stated that each utility interested in a specific CT change was required to evaluate the impact of the change on plant risk following a method developed as part of this program. Plant-specific calculations were required due to the differences between: (1) plant designs, (2) component and system reliabilities, and (3) plant operating experience.

Although the proposed TS changes are intended to be generically applicable, the specific characteristics of each plant will require plant-specific evaluations of the proposed CTs, consistent with NRC guidance in RGs 1.174 and 1.177 regarding additional Tier 1, 2, and 3 guidance, as outlined in this safety evaluation (SE). Thus, the NRC staff views the plant-specific information provided in TR WCAP-15622, Revision 0, as demonstrating the methodology, as opposed to supporting an NRC staff finding on the plant-specific results.

The methodology presented in TR WCAP-15622, Revision 0, requires each licensee requesting the change to evaluate the specific changes to plant risk on a plant-specific basis. As the TR notes, differences in plant design, components, reliability, operating history, vulnerabilities, and initiating events (external and internal) require a plant-specific evaluation. Licensee applications, when submitted in conjunction with RGs 1.174 and 1.177 and the additional information, in Section 4.0 of this SE, should enable a limited review scope by the NRC staff.

The TR references the following plants as providing data and requesting the proposed extended CTs, although it is stated that not all plants requested all of the proposed CT extensions in the TR:

— Callaway Plant
— Comanche Peak Steam Electric Station
— McGuire Nuclear Station
— Sequoyah Nuclear Plant

As discussed above, the NRC staff views these plants as demonstrations of the methodology in TR WCAP-15622, Revision 0, but is not making any finding on the acceptability of these plants to implement the proposed changes. Each licensee will need to make a plant-specific license submittal for any of the proposed changes.

A.2 NRC Staff PRA Review Methodology

The proposed changes are based on a risk-informed PRA approach using risk insights to justify changes to TS CTs. The risk metrics used by the TR to evaluate the impact of the proposed changes are consistent with those presented in RGs 1.174 and 1.177.

In reviewing TR WCAP-15622, Revision 0, the NRC staff used a three-tier approach to evaluate the methodology developed to determine the risk associated with the proposed changes in CTs. The NRC staff based its approach on the guidance of RGs 1.174 and 1.177 and Chapters 16.1 and 19.0 of NUREG-0800. In the three-tier approach, the first tier assesses the licensee's PRA and impact of the proposed changes on plant operational risk, as estimated by the change in core damage frequency (ΔCDF) and the estimated change in large early release frequency (ΔLERF). The estimated change in risk is compared to the acceptance guidelines as stated in RG 1.174. The first tier also reviews the proposed change to ensure that plant incremental risk estimates for equipment taken out of service during the proposed CT satisfy the acceptance guidelines for ICCDP and ICLERP, as stated in RG 1.177. The Tier 1 review involves the evaluation of the validity of the plant-specific PRA model and its application to the proposed CT extension, as well as the evaluation of the PRA results and insights with respect to the extended CT.

Tier 2 identifies the need to preclude potentially high-risk plant configurations that could result if equipment, in addition to that associated with the proposed change, is taken out of service simultaneously, or if other risk-significant operational factors, such as concurrent system or equipment testing, are also scheduled. A Tier 2 review ensures that appropriate restrictions on dominant risk-significant plant configurations associated with the CT extension are in place.

Tier 3 provides for the establishment of a configuration risk management program (CRMP) and confirmation that the decision making process incorporates its insights before equipment is taken out of service before or during the CT. The Tier 3 program ensures that programs and procedures are in place for the identification of risk-significant configurations resulting from maintenance or other operational activities and that appropriate compensatory measures are taken to avoid such configurations. Tier 3 provides additional coverage over Tier 2 for any other risk-significant configurations that may be encountered during maintenance scheduling over extended periods of plant operation. The Maintenance Rule (10 CFR 50.65(a)(4)), which requires a licensee to assess and manage the increase in risk that may result from activities such as surveillance, testing, and corrective and preventive maintenance, can satisfy Tier 3 guidance as specified in RG 1.177, Section 2.3.7.1.

A.3 Tier 1, PRA Capability and Insights

TR WCAP-15622, Revision 0, presented an approach, in addition to that of RGs 1.174 and 1.177, that followed a defined methodology. The report sought to provide a method that would result in a consistent risk analysis among the submitted plants, enabling direct comparisons of each plant's specific results. The general approach included the following activities:

- Identify the TS CT improvement.
- Determine the impact on plant safety.
- Identify the impact of the change on the plant PRA model.
- Modify the plant PRA model and associated CT.
- Identify the risk measures.
- Quantify the plant-specific model.
- Collect and discuss preliminary results.
- Collect and review final results.
- Identify the change requests.
- Prepare documentation.

TR WCAP-16522, Revision 0, identified three key aspects to the analysis methodology as: (1) define the specific model and analysis requirements, (2) perform utility plant-specific evaluations, and (3) review the plant-specific results. The process outlined in Section 8.1 and the more detailed guidance given in Appendix C to the TR are similar to and complements the guidance provided by RGs 1.174 and 1.177, including guidance to help ensure consistent evaluations among plants.

The TR provides a Tier 1 discussion and partial quantitative evaluation for the proposed CT for electrical power system AC sources, DGs, and vital AC buses with respect to RGs 1.174 and 1.177 risk metrics for ΔCDF and ICCDP. The NRC staff recognizes that four plants (Callaway, Comanche, McGuire, and Sequoyah) responded to the NRC and staff RAIs, providing revised values of ΔCDF, ICCDP from those originally referenced in TR WCAP-15622, Revision 0. In addition, the four plants also provided values for ΔLERF and ICLERP. However, aside from these responses, TR WCAP-15622, Revision 0, does not address ΔLERF or ICLERP in the analysis, based on the argument that the proposed changes do not independently impact containment systems and do not generically apply to plants incorporating TR WCAP-15622, Revision 0. The NRC staff has not accepted this approach in previous DG extended-CT plant evaluations and has found that plant-specific results are generally needed to complete a review. Therefore, licensees must perform, on a plant-specific basis, ΔLERF and ICLERP evaluations for the proposed CTs.

The TR evaluates the impact of the proposed CT changes on CDF and ICCDP. The TR provides a process to evaluate plant-specific PRA models using a methodology described in Appendices C, D, E, and F. The methodology provides results consistent with the process described by TR WCAP-15622, Revision 0, and presents a comparison among the participating plants. The TR states that this approach is consistent with the guidance provided by RGs 1.174 and 1.177. Although TR WCAP-15622, Revision 0, provides a framework to evaluate the proposed CTs, licensees must evaluate their submittals according to the guidance and acceptance guidelines contained in RGs 1.174 and 1.177, including supplemental Tier 1 guidelines as described below, and submit plant-specific Tier 2 and 3 analyses.

Appendix C to the TR provides a general process for using a PRA to develop and evaluate the proposed CT changes in TR WCAP-15622, Revision 0, with reference to RGs 1.174 and 1.177. The licensees would use this general process to identify the: (1) TS requirements to be evaluated, (2) scope of the change with respect to the PRA, (3) PRA modifications, (4) risk metrics to be referenced, and (5) evaluation of Tier 1, 2, and 3 criteria, including the development of a risk-informed submittal and data collection.

(a) PRA Capability:

The PRA capability review determines whether the plant-specific risk assessments used in evaluating the proposed extended CTs are of sufficient scope and detail. Because the TR presents a methodology for performing an analysis using a plant-specific PRA, the capability of each licensee's PRA is not specifically addressed. The NRC staff reviewed the information provided in TR WCAP-15622, Revision 0, and, based on the above discussion, concludes that although the TR addressed the issue of capability, the methodology does not provide sufficient means to ascertain PRA quality for a plant-specific submittal requesting the proposed extended CTs. Therefore, for these CT changes, each licensee must provide for NRC staff review a discussion of the plant-specific PRA quality justifying its acceptability for the application in accordance with the guidelines given in RG 1.174.

To ensure the acceptability of a licensee’s request, additional information on PRA quality is required by NRC in the following areas:

- Assurance that the plant-specific PRA reflects the as-built, as-operated plant.

- Assurance that the applicable PRA updates include the findings from the individual plant evaluation (IPE) and IPE for external events. External events may include seismic, high winds, fires, floods, or other related events applicable to each licensee.

- Assurance that conclusions from the peer review, including both A and B facts and observations, per NEI 00-02, “Probabilistic Risk Assessment (PRA) Peer Review Process Guidance,” Revision A3 that are applicable to the proposed extended CTs were considered and resolved. If not resolved, justification for acceptability of the conclusions (e.g., sensitivity studies showing negligible risk impact) should be provided. The licensee should indicate the PRA revision that underwent peer review and the PRA revision that was used in the plant-specific application. RG 1.200, Revision 1, “An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessments Results for Risk-Informed Activities,” provides guidance to address PRA technical adequacy.

- Assurance that there is PRA configuration control and updating, including PRA quality assurance programs, associated procedures, and PRA revision schedules.

- Assurance that there is PRA adequacy, completeness, and applicability with respect to evaluating the risk associated with the proposed CT extensions.

- Assurance that plant design or operational modifications that are related to or could impact the proposed CT extensions are reflected in the PRA revision used in the plant-specific application, or a justification is provided for not including these modifications in the PRA.

The additional information listed above on PRA quality is in Section E.2 of Appendix E of this SE.

(b) PRA Insights:

One approach to demonstrate the acceptability of the risk impact of a proposed change is to show that the licensing basis for the proposed change meets the key principles set forth in RG 1.174. One such principle involves demonstrating that when the proposed change results in an increase in CDF or risk, the increased risk is small. In addition, the impact of the proposed change should be monitored using performance measurement strategies. RGs 1.174 and 1.177 provide acceptance guidelines for meeting these principles. Specifically, those guidelines include ΔCDF, ΔLERF, ICCDP, and ICLERP. The risk metrics ICCDP and ICLERP provided in RG 1.177 are used in addition to the metrics outlined in RG 1.174 for the evaluation of CTs, because CTs are entered infrequently and are temporary in nature. As a result, the single CT risk may be significant even though the CDF and LERF estimates indicate little increase in risk.

Tables 8-1, 8-5, and 8-6 of TR WCAP-16522, Revision 0, summarize the risk impact of extending the CTs for the participating plants. The results show that the risk impact of the proposed CTs is generally within the acceptance guidelines for small changes in CDF given in RG 1.174. However, the results for ICCDP generally show that the RG 1.177 acceptance guidelines are exceeded for the proposed CTs. As stated earlier, the TR does not include estimates for LERF or ICLERP for the proposed extended CTs, which must be included in plant-specific submittals.

In addition, some of the licensees who provided plant-specific information as part of TR WCAP-15622, Revision 0, re-evaluated the proposed CT extensions. In the RAI responses, the licensees proposed changes to the plant-specific results/analysis provided in TR WCAP-15622, Revision 0, including:

- Revising the analysis based on updated PRA models.

- Crediting compensatory measures to reduce LOOP frequencies during maintenance activities. The measures included restricted switchyard activities and the time of year maintenance is scheduled.

- Reducing the CT from that originally proposed in TR WCAP-15622, Revision 0.

As part of the reevaluation, the PWROG suggested a revised methodology to credit compensatory measures by calculating a plant-specific LOOP frequency. Essentially, the approach is based on a review of LOOP events and the applicability of these events to a specific plant. Using the proposed compensatory measures to be implemented during DG maintenance, a number of LOOP events may be removed from the LOOP event frequency calculation. RG 1.177 provides guidance in this area and states that certain compensatory measures that balance the calculated risk increase caused by the CT changes would be considered by the NRC staff. However, it further states that compensatory measures considered as part of the analysis of the CT changes should: (1) be included in the overall TS change, (2) not be relied upon to compensate for weaknesses in plant design, and (3) not be measures that the licensee has taken credit for in a previous licensing action. In addition, licensees proposing compensatory measures in their plant-specific submittals should discuss the incorporation of these measures into the plant (1) operating practices and procedures and (2) PRA model. The discussion should include how the measures are modeled, the human error probabilities for operator action, and the contribution of the proposed compensatory measures to CT risk. The NRC staff will consider this as Tier 2 information in its review of plant-specific submittals for plants implementing the proposed CT extensions.

In addition to the shutdown risk arguments presented for the DG CT extension request, TR WCAP-15622, Revision 0, also includes a general qualitative transition risk argument that the proposed DG CT extensions avoid transition risk. The NRC staff finds that the transition risk argument has merit for circumstances when unscheduled maintenance cannot be completed within the specified CT. In these cases, the decision to complete the repair at power or during shutdown should consider transition risk. However, based on the proposed CTs in TR WCAP-15622, Revision 0, the reason for the requested CT appears to include the operational flexibility to conduct additional scheduled maintenance activities at power where transition risk is not avoided.

In conclusion, as shown in the TR WCAP-15622, Revision 0, tables, the results for CDF and ICCDP are not consistently within the acceptance guidelines for RGs 1.174 and 1.177.

A.4 Tier 2, Avoidance of Risk-Significant Plant Configurations

Tier 2 information concerns the licensee's evaluation of risk-significant equipment outage configurations that may occur when plant equipment is out of service when the licensee enters the LCO related to the proposed TS change. TR WCAP-15622, Revision 0, does not specifically address Tier 2 because of the variation of participating plant system designs. Therefore, the TR stated that each individual licensee will include a Tier 2 assessment of the proposed CT changes in its plant-specific submittal. The licensee will evaluate plant equipment in combination with equipment included under the proposed CTs to identify any risk-significant configurations and necessary compensatory measures that may be required. Therefore, the NRC staff limited its review of Tier 2 with respect to TR WCAP-15622, Revision 0, except to note that TR WCAP-15622, Revision 0, states that Tier 2 will be addressed in the plant-specific submittal and evaluated per RG 1.177 guidelines.

In its appendices, TR WCAP-15622, Revision 0, provides minimal guidance on cumulative risk impacts, although risk impact is recognized as part of a risk-informed review. With respect to past submittals and the combined requests within TR WCAP-15622, Revision 0, cumulative risk should be evaluated on a plant-specific basis consistent with the guidance given in RG 1.174. In addition, licensees should consider the guidance given in RG 1.174 for combined change requests.

A.5 Tier 3, Risk-Informed Configuration Risk Management

Tier 3 involves the establishment of a CRMP to ensure the evaluation of the risk impact of out-of-service equipment before performing maintenance activities. The program should also ensure that the proposed CT extensions do not degrade operational safety over time. As part of this program, a licensee should have prior knowledge of high-risk configurations using a risk matrix, PRA analyses, and/or online monitoring. The licensee should have the ability to evaluate configurations and LCO condition risks as plant conditions, equipment, and grid conditions continue to change.

A CRMP ensures that while equipment is in an LCO condition, additional activities will not be performed that could further degrade the capabilities of the plant to respond to a condition normally mitigated by the inoperable equipment or system and, as a result, increase plant risk beyond that assumed by the TR analysis (RGs 1.174 and 1.177 guidelines). The risk-informed CRMP should: (1) ensure that, during equipment maintenance, additional maintenance does not increase the likelihood of an initiating event intended to be mitigated by the out-of-service equipment; (2) evaluate the effects of additional out-of-service equipment during the maintenance activity that would adversely impact CT risk, such as redundant systems or components; and (3) evaluate the impact of maintenance on equipment or systems assumed to remain operable by the CT analysis. The CRMP is a licensee-developed plant-specific program, and WCAP-15622 did not consider the program on a generic basis. Hence, the NRC staff did not review Tier 3 criteria with respect to TR WCAP-15622, Revision 0, except to note that the TR states that a licensee's plant-specific submittal will address Tier 3 criteria.

Accordingly, a licensee should develop a CRMP to ensure that it appropriately evaluates the risk impact of out-of-service equipment before performing a maintenance activity. Licensees can implement the overall CRMP (as referenced in RG 1.177) through the Maintenance Rule (10 CFR 50.65(a)(4)), and the rule requires that, before performing any maintenance activity, the licensee must assess and manage the potential risk increase that may result from a proposed maintenance activity. A licensee's plant-specific submittal must discuss the licensee's CRMP for assessing the associated risk when equipment is removed from service and its conformance to the requirements of 10 CFR 50.65(a)(4), as it relates to the proposed CTs. This discussion should be consistent with the Tier 3 and CRMP guidelines that are outlined by RG 1.177, Section 2.3.7.1.

In addition, RG 1.174 states that an implementation and monitoring plan should be developed to ensure that the impacts of the proposed changes continue to reflect the actual reliability and availability of the SSCs evaluated to support the proposed CT extensions. Monitoring performed in conformance with the maintenance rule of 10 CFR 50.65 can be used when such monitoring is sufficient for the SSCs affected by the risk-informed application. Licensees requesting these TS changes must confirm plant-specific implementation and monitoring in their plant-specific submittal. This includes the additional information on PRA quality identified in Section A.3 above.

A.6 Comparison with Regulatory Guidance

The NRC staff found the risk evaluation methodology in TR WCAP-15622, Revision 0, to be consistent with the guidance in RGs 1.174 and 1.177; however, the results of the submitted plant evaluations indicate in a number of cases an increase in risk from the proposed extension of DG and vital AC bus CTs that was larger than the acceptance guidelines of the RGs. Each licensee requesting these TS changes must submit a plant-specific analysis to account for the plant-specific characteristics, procedures, and practices, as identified by this SE.

APPENDIX B

REQUIREMENTS IN GENERAL DESIGN CRITERION (GDC)-17 AND RECOMMENDATIONS IN REGULATORY GUIDE (RG) 1.9

The GDC-17 requires that the onsite power system (i.e., the emergency DG) have: (A) sufficient capacity and capability (assuming the offsite system is unavailable) to assure that: (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents; (B) sufficient testability to perform their functions assuming a single failure; and (c) provisions to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.

In regard to periodic testing of DGs, Regulatory Position C.2.3.2, "Surveillance Testing," of RG 1.9 and Section 6.5, "Periodic Tests," of Institute of Electrical and Electronic Engineers Standard 387-1984 (IEEE 387) provide the following recommendations for satisfying GDC-17:

- Section 6.5 of IEEE 387 states that the DG is to be started and loaded at intervals of no longer than 1 month to the capacity recommended by the manufacturer.

    - Regulatory Position C.2.3.1 recommends that Section 6.5 of IEEE 387 is to be supplemented with a start and load-run tests at least once in 31 days with maximum allowable extension not to exceed 25 percent of the surveillance interval.

    - Regulatory Position C.2.3.2 recommends Section 6.5 of IEEE 387 is to be supplemented with a fast start and load-run tests once every 6 months.

    The start and load-run tests mentioned in the two bullets above are to demonstrate: (1) proper startup from standby conditions and to verify that the required voltage and frequency is attained and (2) the DG can be loaded to 90 to 100 percent of the continuous rating, for an interval of not less than 1 hour and until temperature equilibrium has been attained, respectively. For the start tests, the emergency DG can be slow started and reach rated speed on a prescribed schedule that is selected to minimize stress and wear. The load-run test may be accomplished by synchronizing the DG with offsite power where the loading and unloading of a DG during this test should be gradual and based on a prescribed schedule that is selected to minimize stress and wear on the DG.

- Section 6.5 of IEEE 387 states that the DG unit should be given one cycle of each of the following tests, at least once every 18 months, to demonstrate its continued capability of performing its required function:

    - Starting test to demonstrate the capability to attain and stabilize frequency and voltage within the limits and time defined in the equipment specification.

- Load acceptance test to demonstrate the capability to accept the individual loads that make up the design load in the desired sequence and time duration and to maintain the voltage and frequency within the acceptable limits.

- Rated load test to demonstrate the capability of carrying the following loads for the indicated times without exceeding the manufacturer's design limits:

  - A load equal to the continuous rating for a time required to reach engine temperature equilibrium plus 1 hour.

  - Immediately following, the rated short-time load shall be applied for a period of 2 hours.

- Load rejection test to demonstrate the capability of rejecting short-time rated load without exceeding speeds or voltages which will cause tripping or component damage.

- Subsystem tests to demonstrate the capability of the control, surveillance, and protection systems to function in accordance with the requirements of the intended application.

- Regulatory Position C.2.3.3 recommends Section 6.5 of IEEE 387 to be supplemented with the following tests to demonstrate overall emergency DG unit design capability at every refueling outage:

  - Fast start test to demonstrate that each emergency DG unit starts from standby conditions and reaches required voltage and frequency within acceptable limits and time.

  - LOOP test to demonstrate (by simulating a LOOP) that: (1) the emergency buses are de-energized and the loads are shed from the emergency buses and (2) the emergency DG starts on the autostart signal from its standby conditions, attains the required voltage and frequency and energizes permanently connected loads within acceptable limits and time, energizes the autoconnected shutdown loads through the load sequencer, and operates for greater than or equal to 5 minutes.

  - Safety injection actuation signal (SIAS) test to demonstrate that, on a SIAS, the emergency DG starts on the autostart signal from its standby conditions, attains the required voltage and frequency within acceptable limits and time, and operates on standby for greater than or equal to 5 minutes.

  - Combined SIAS and LOOP tests to demonstrate that the emergency DG can satisfactorily respond to a LOOP in conjunction with SIAS in whatever sequence they might occur.

- Single-Load Rejection test to demonstrate the emergency DG's capability to reject a loss of the largest single load while operating at power factor between 0.8 and 0.9 and verify that the voltage and frequency requirements are met and that the emergency DG will not trip on overspeed.

- Full-Load Rejection test to demonstrate the emergency DG's capability to reject a load equal to 90 to 100 percent of its continuous rating while operating at power factor between 0.8 and 0.9, and verify that the voltage requirements are met and that the emergency DG will not trip on overspeed.

- Endurance and Margin test to demonstrate full-load carrying capability at a power factor between 0.8 and 0.9 for an interval of not less than 24 hours, of which 2 hours are at a load equal to 105 to 110 percent of the continuous rating of the emergency DG, and 22 hours are at a load equal to 90 to 100 percent of its continuous rating and verify that voltage and frequency requirements are maintained.

- Hot Restart test to demonstrate hot restart functional capability at full-load temperature conditions (after it has operated for 2 hours at full load) by verifying that the emergency DG starts on a manual or autostart signal, attains the required voltage and frequency within acceptable limits and time, and operates for longer than 5 minutes.

- Synchronizing test to demonstrate the ability to: (1) synchronize the emergency DG unit with offsite power while the unit is connected to the emergency load, (2) transfer this load to the offsite power, and (3) restore the emergency DG to ready-to-load status.

- Protective Trip Bypass test to demonstrate that all automatic emergency DG trips (except engine oversewed, generator differential, and those retained with coincident logic) are automatically bypassed upon an SIAS.

- Test Mode Change-Over test to demonstrate that, with the emergency DG operating in a test mode while connected to its bus, a simulated SIAS overrides the test mode by (1) returning the emergency DG to standby operation and (2) automatically energizing the emergency loads from offsite power.

APPENDIX C

REACTOR COOLANT PUMP (RCP) SEAL MODEL

The use of a particular model for a RCP seal loss-of-coolant accident (LOCA) is not addressed in Appendix D of TR WCAP-15622, Revision 0, which provides the specific analysis requirements for evaluating changes to completion times (CTs). To address the impact of different RCP-seal-LOCA models, TR WCAP-15622, Revision 0, looked at the sensitivity of the V.C. Summer Nuclear Station (Summer) base case probabilistic risk assessment (PRA) by replacing the TR WCAP-15622, Revision 0, RCP seal model with the "Brookhaven" RCP seal model (with additional modifications) and, in response to a NRC staff request for additional information, included additional sensitivity studies using other RCP seal models (e.g., the Rhodes model discussed below). The Pressurized Water Reactor Owners Group (PWROG) stated it chose the Summer model because this plant has the largest station blackout (SBO) contribution to core damage frequency (CDF) of all the submitted plants included in TR WCAP-15622, Revision 0. However, WCAP-15622 did not examine the sensitivity of each participating plant to the RCP seal model used by the licensee.

In the closeout of Generic Safety Issue 23, "Reactor Coolant Pump (RCP) Seal Failure," the NRC staff stated that until better models were developed to support future risk-informed licensing decisions, the NRC staff would use the Rhodes model, which is described in Appendix A to NUREG/CR-5167, to determine the contribution to CDF from RCP seal LOCAs. The PWROG submitted WCAP-15603, "WOG 2000 Reactor Coolant Pump Seal Leakage Model for Westinghouse PWRs," which presents a consensus RCP seal leakage model (referenced as the WOG 2000 RCP seal model) for plants that use the Westinghouse seal package with O-rings qualified for high temperature, and the NRC staff issued its safety evaluation (SE) for WCAP-15603, Revision 1, on April 4, 2003.

The NRC staff noted in its SE for WCAP-15603, Revision 1, that licensees currently use several different models for RCP seal cooling. The variations in models and assumptions have led to modeling inconsistencies in PRAs and raised NRC staff concerns when these PRAs are used to support risk-informed licensing actions. The NRC staff found in its SE that WCAP-15603, Revision 1, is acceptable for referencing in licensing and other applications, to the extent specified and under the limitations delineated in the TR and the NRC SE for those plants using high-temperature O-rings. For plants using the "old" O-rings, the NRC SE stated that the NRC staff expects licensees to use the Rhodes model for Westinghouse seal packages. The NRC staff SE also cautions that, for plants using RCP models other than the Rhodes model (for plants equipped with “old” O-rings) or WOG-2000 RCP seal model (for plants equipped with O-rings qualified for high temperature), a licensee must provide justification for its model, including any additional supporting analyses and related bases that are necessary to verify the appropriateness of the model used in licensee PRA documentation.

Based on the above, it is expected that, for a plant-specific CT extension application, the licensee should include documentation on the RCP seal model employed at the plant.

APPENDIX D

DESCRIPTION OF APPLICABLE ELECTRICAL SYSTEMS AND COMPONENTS

AC Electric Power Systems:

According to the improved standard Technical Specifications (ISTS), the Class 1E alternating current (AC) electrical power system sources consist of the offsite power sources (i.e., preferred power sources, normal and alternate(s)) and the onsite standby power sources (e.g., emergency diesel generators (DGs)). As required by General Design Criterion (GDC)-17, the design of the AC electrical power system must provide independence and redundancy to ensure an available source of power to the engineered safety feature (ESF) system.

The onsite Class 1E AC distribution system is typically divided into redundant load groups (trains) so that the loss of any one group does not prevent the performance of minimum safety functions. Each group typically has connections to two preferred offsite power sources and a single DG. Transmission lines supply offsite power from the transmission network to the unit switchyard. From the switchyard, two physically separated circuits that can be electrically separated are provided from a transmission network provide AC power to the 4.16 kV ESF buses.

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E ESF bus(es). Certain required unit loads are returned to service in a predetermined sequence to prevent overloading the transformer supplying offsite power to the onsite Class 1E distribution system. After receipt of an initiating signal, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are returned to service via the automatic load sequencer.

A dedicated DG typically serves as the onsite standby power source for each 4.16-kv ESF bus. A DG starts automatically on a safety injection (SI) signal (e.g., low pressurizer pressure or high containment pressure signals) or on an ESF bus degraded voltage or undervoltage signal. After the DG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of an ESF bus undervoltage or degraded voltage, independent of or coincident with a SI signal. The DGs will also start and operate in the standby mode without tying to the ESF bus on a SI signal alone. Following a loss-of-offsite power (LOOP) trip, nonpermanent loads are stripped from the ESF bus. When the DG is tied to the ESF bus, loads are then sequentially connected to its respective ESF bus by the automatic load sequencer.

The operability of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This results in maintaining at least one train of the onsite or offsite AC sources operable during accident conditions in the event of: (1) an assumed LOOP, or loss of all onsite AC power, and (2) a worst-case single failure.

AC Electric Power Distribution Systems:

The onsite Class 1E AC, direct current (DC), and AC vital bus electrical power distribution systems are divided by train into redundant and independent AC, DC, and AC vital electrical power distribution buses and their subsystems.

The AC electrical power subsystem for each train consists of a primary ESF bus and secondary buses, distribution panels, motor control centers, and load centers. Each ESF bus has an offsite source of power as well as a dedicated onsite DG source. Each ESF bus is either normally connected to a preferred offsite source or the preferred offsite source is available within a few seconds following a trip of the main unit DG. After a loss of the preferred offsite power source to an ESF bus, a transfer to the alternate preferred offsite source may be initiated. If all offsite sources are unavailable, the onsite emergency DG supplies power to the ESF bus. The Class 1E DC system buses supply control power for their associated AC buses.

The 120 volts AC vital buses are arranged in two load groups per train and are normally powered from inverters. The alternate power supplies for the vital buses if included as part of the design are generally constant voltage source transformers.

The initial conditions of design-basis accidents and transient safety analyses assume that the ESF system is operable. The AC, DC, and AC vital bus electrical power distribution systems are designed to provide sufficient capacity, capability, independence, redundancy, and reliability to ensure the availability of necessary power to the ESF system so that the fuel, reactor coolant system, and containment design limits are not exceeded.

The operability of the AC, DC, and AC vital bus electrical power distribution systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining power distribution systems operable during accident conditions in the event of: (1) an assumed loss of all offsite power or all onsite AC electrical power and (2) a worst case single failure. The distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

APPENDIX E

ADDITIONAL INFORMATION NEEDED FOR PLANT-SPECIFIC APPLICATIONS

E.1 Plant-Specific Information Identified in Appendix D of TR WCAP-15622, Revision 0:

1. Provide the loss-of-offsite power (LOOP) initiating event frequency and basis.

2. Provide a short discussion of the LOOP events that have occurred at the plant and compare this frequency to the LOOP frequency used in the probabilistic risk assessment (PRA) model.

3. If the plant can cross-connect the redundant ESF buses, explain how the PRA models this. How long does it take to establish the crosstie? How much credit is taken? (This can be shown via a sensitivity study to determine the impact of crediting the crosstie on core damage frequency (CDF)).

4. If the plant has an alternate alternating current (AC) source, is it covered under the Maintenance Rule (10 CFR 50.65) program? If not, explain why. Is the alternate AC source hardened against severe weather? How much credit has been taken with respect to the alternate AC source's ability to decrease CDF? (This can be shown via a sensitivity study to determine the impact of crediting the alternate AC source on CDF).

5. Provide the CDF for station blackout (SBO) events as reported for the individual plant evaluation (IPE). Provide the failure rates for DG failure to start (per demand) and failure to run (per hour), as well as the LOOP initiating event frequency used in the IPE.

6. Provide the CDF for SBO events as calculated for this study and explain the difference between this value and the value reported in the IPE. Consider revised LOOP initiating event frequency, credit for alternate AC sources, credit for crossties, and the completion time (CT) change.

E.2 PRA Quality and Plant Tier 2 and Tier 3:

1. To address plant-specific issues, additional information on the plant-specific PRA is required in the following areas:

    (a) Assurance that the plant-specific PRA reflects the as-built, as-operated plant.

    (b) Assurance that the applicable PRA updates include the findings from the IPE and IPE for external events. External events may include seismic, high winds, fires, floods, or other related events applicable to each licensee.

    (c) Assurance that conclusions from the peer review, including both A and B facts and observations, per Nuclear Energy Institute (NEI) 00-02, "Probabilistic Risk Assessment (PRA) Peer Review Process Guidance," Revision A3 that are applicable to the proposed extended CTs were considered and resolved. If not resolved, justification for acceptability of the conclusions (e.g. sensitivity studies showing negligible risk impact) was provided. The licensee should indicate the PRA revision that underwent peer review and the PRA revision that was used in the plant-specific application. RG 1.200, Revision 1, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessments Results for Risk-Informed Activities," provides guidance to address PRA technical adequacy.

(d) Assurance that there is PRA configuration control and updating, including PRA quality assurance programs, associated procedures, and PRA revision schedules.

(e) Assurance that there is PRA adequacy, completeness, and applicability with respect to evaluating the risk associated with the proposed CT extensions.

(f) Assurance that plant design or operational modifications that are related to or could impact the proposed CT extensions are reflected in the PRA revision used in the plant-specific application or a justification is provided for not including these modifications in the PRA.

(g) An evaluation of the change in large early release frequency (ΔLERF) or incremental conditional large early release probability (ICLERP) for the proposed extended CTs, and address the impact of the proposed CT on dominant accident sequences with respect to risk outliers;

(h) With respect to previous submittals and the extended CTs in TR WCAP-15622, Revision 0, licensees will evaluate cumulative risk on a plant-specific basis consistent with the guidance given in RG 1.174. In addition, licensees will address the guidance for combined change requests provided in RG 1.174.

2. Licensees should provide supplemental Tier 1, 2, and 3 evaluations on a plant-specific basis consistent with the guidance given in Sections 8.5 and 8.6 of the TR and the acceptance guidance of RGs 1.174 and 1.177.

3. Licensees should confirm that, when evaluating the proposed CT extensions, the diesel generator (DG) PRA model repair/recovery has been modified with respect to the increased DG CT.

E.3 Associated Extended CT for LOOP DG Start Instrumentation:

- The NRC staff did not consider an associated CT for the LOOP DG start instrumentation as part of its review of TR WCAP-15622, Revision 0. If such an association exists with the CTs for this instrumentation as part of the plant-specific application, the licensee must provide the impact and basis for such an association, or propose TS changes to separate the CT in the plant Technical Specifications (TSs) for improved standard TS (ISTS) Limiting Condition for Operation (LCO) 3.5.5, Condition C from the CTs for an inoperable DG.

E.4 Commitments Needed From Licensees:

These commitments should be addressed by the licensee in the appropriate TS Bases for the plant-specific TS license amendment request.

1. Licensees should commit to evaluate weather conditions before entering the extended CT for voluntary planned maintenance. An extended CT will not be entered for voluntary planned maintenance purposes if official weather forecasts are predicting severe weather conditions.

2. Licensees should commit to evaluate the condition of the offsite power supply and switchyard, including grid stability/reliability, before entering an extended CT (see also Regulatory Issue Summary 2004-05, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power"). An extended CT would not be entered if the evaluation indicated an unacceptable potential for losing offsite power.

3. Licensees should commit to assuring that no discretionary switchyard maintenance or discretionary maintenance on the main or startup transformers associated with the unit will be performed during entry into an extended CT.

4. Licensees should commit to assuring that no maintenance or testing that affects the operable train associated with the operable DG/vital AC bus will be scheduled during entry into an extended CT.

5. Licensees should discuss the restrictions, commitments, or limitations on CT entry during an operating cycle, consistent with the PRA analysis.

E.5 Alternative Power Sources, Cross-Connecting Safety Buses, and Other Compensatory Measures:

1. If alternate power sources, cross-connecting safety buses, or other compensatory measures are provided to support the plant-specific application, the licensee should provide a design description and analyses demonstrating compliance of the electrical design with General Design Criterion (GDC)-17, for the cases of when the compensatory measures are (1) being used and (2) not being used.

2. For alternate power sources, licensees should discuss the resistance to external events (including weather-related events), environmental protection, and operational parameters, such as the ability to supply safety-related and/or nonsafety-related loads. The alternate source's availability, reliability (including any black-start capability), and surveillance requirements, as related to maintenance activities, should be provided. Required operator actions and their

human error probabilities should be provided, as well as procedural modifications or requirements. Finally, a discussion of the applicability of Information Notice 97-21, "Availability of Alternate AC Power Source Designed for Station Blackout Event," dated April 18, 1997, should also be provided. The information notice alerted licensees to the potential unavailability of an alternate AC power source during a SBO event.

3. For a crosstie or cross-connecting safety buses and other compensatory measures, licensees should provide information on the required operator actions, the human error probability, and the operator training, including procedures and demonstrated operator action capability.

E.6 Reactor Coolant Pump (RCP) Seal Model:

- For a plant-specific DG CT extension submittal, licensees should include plant-specific documentation on the RCP seal model employed.

E.7 Post-Maintenance Testing Following Online DG Maintenance:

1. As discussed in the SE, Section 3.5.2.1, having an extended CT to permit online DG maintenance requires conducting post-maintenance testing of the DG online to demonstrate operability. Online post-maintenance testing, as required in the TSs, should be addressed in the plant-specific application with respect to: (1) showing the DG is operable and can perform its safety functions; (2) being consistent with the recommended tests in RG 1.9 and Section 6.5 of Institute of Electrical and Electronics Engineers (IEEE) Standard 387, which demonstrate compliance with GDC-17; and (3) performing tests online that do not prevent the DG from performing its safety functions and do not cause the risk associated with testing the DG connected to the grid to be unacceptable, including the following:

    (a) Discuss the impact of the DG and offsite power sources being connected and subject to a common mode failure for a longer period of time due to online maintenance. Compensatory measures and compliance with regulatory requirements should be addressed.

    (b) Discuss the testing that is used following online maintenance activities to demonstrate DG operability.

    (c) Confirm that the DG would be disconnected from the plant electrical system during online preventive maintenance activities.

    (d) Discuss the precautions taken to ensure that plant electrical distribution system transients that could impact plant operation do not occur during maintenance activities or post-maintenance testing.

2. Licensees should describe their program to manage the risk of DG and vital AC bus maintenance evolutions with online maintenance programs and in-place procedures to implement 10 CFR 50.65(a)(4) and the guidance contained in

RG 1.182, consistent with the Tier 3 and configuration risk management program (CRMP) guidelines outlined by RG 1.177.

E.8 Maintenance Rule and SBO:

- The licensees' plant-specific submittals should provide the following information regarding Maintenance Rule implementation and monitoring goals, and a comparison of actual DG performance with SBO commitments (including alternate AC sources, if applicable):

  — DG failure-to-start and failure-to-run probabilities.

  — DG maintenance unavailability with a 3-day and a 7-day CT.

  — alternate AC source failure probability values (if applicable).

  — alternate AC source maintenance unavailability (if applicable).

  — a discussion of the above values with respect to Maintenance Rule goals, actual DG performance, and SBO commitments, ensuring that the proposed CT meets the objectives of the Maintenance Rule (10 CFR 50.65) and the SBO Rule (10 CFR 50.63).

APPENDIX F

SECOND COMPLETION TIME (CT) FOR AN INOPERABLE DIESEL GENERATOR (DG) OR VITAL ALTERNATING CURRENT (AC) BUS

Because TR WCAP-15622, Revision 0, has proposed to extend the CTs for an inoperable DG or vital AC bus, the second CTs in Technical Specifications (TSs) 3.8.1 and 3.8.9 would also be extended. Therefore, TR WCAP-15622, Revision 0, also identified extended second CTs of: (1) 10 days (from 6 days) for an extended CT of 7 days for an inoperable DG; and (2) 32 hours (from 16 hours) for an inoperable vital AC bus. The second CT establishes a limit on the maximum time allowed for a combination of inoperable equipment in the same limiting condition for operation (LCO) during contiguous occurrences of failing to meet the LCO and are addressed in Section 3.6 of this SE.

F.1 LCO 3.8.1

The LCO 3.8.1, Required Actions A.3 and B.4 contain a second CT that is also proposed to be extended in accordance with WCAP-15622. This CT establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during a single contiguous occurrence to meet the LCO. This CT limits the time allowed in a specific condition after the discovery of a failure to meet the LCO. The second CT of 6 days is extended to 10 days, consistent with the proposed DG CT and consistent with the intent of the improved standard TSs (ISTS) in that the proposed 10-day CT is a combination of Required Action A.3, "Restore Offsite Circuit to Operable Status," and B.4, "Restore DG to Operable Status," CTs and not based on a risk-informed approach. Both conditions apply simultaneously, and the more restrictive CT must be met.

The second CT of 10 days (proposed to be changed from 6 days), establishes a limit on the maximum time allowed for any combination of an offsite circuit and DG being inoperable during any single contiguous occurrence of failing to meet LCO 3.8.1. For example, if the CT of 72 hours for an inoperable offsite circuit is entered during the CT of 7 days (proposed to be changed from 3 days) for an inoperable DG that is returned to operable status, the LCO may already have been not met for up to the CT of 7 days for an inoperable DG. This situation could lead to a total of 10 days from the initial failure to meet the LCO due to an inoperable DG, to restore the offsite circuit to operable status. At this time, a DG could again become inoperable and an additional CT of 7 days for the inoperable DG could be allowed prior to complete restoration of the LCO. This situation could continue indefinitely if not limited. The second CT of 10 days (proposed to be changed from 6 days) limits the time the plant can alternate between the conditions of an inoperable offsite circuit, an inoperable DG, and the combined inoperability of an offsite circuit and DG without meeting the LCO.

No second CT was established in the standard TSs (STS), but the ISTS established a second CT to limit the time a plant can alternate between the condition of an inoperable offsite circuit, an inoperable DG, and the combined inoperability of an offsite circuit and DG without meeting the LCO. The ISTS states that a 6-day time limit, which would be based on the sum of the CTs for multiple conditions - a CT of 3 days for an inoperable offsite circuit plus a CT of 3 days for an inoperable DG, is considered reasonable for this second CT.

Based on this information, the NRC staff concludes that the algebraic sum of the extended CT for an inoperable DG and the CT for an inoperable offsite circuit to determine the second CT for an inoperable DG is acceptable. The individual CTs would be approved separately, but the second CT would be the sum of the individual CTs.

F.2 LCO 3.8.9

LCO 3.8.9, Required Actions A.1, B.1, and C.1, contain a second CT that is also extended per TR WCAP-15622, Revision 0. This CT establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during a single contiguous occurrence to meet the LCO. This CT limits the time allowed in a specific condition after the discovery of a failure to meet the LCO. The second CT of 16 hours is extended to 34 hours, consistent with the proposed AC vital bus CT and consistent with the intent of the ISTS in that the proposed 34-hour CT is a combination of the AC vital bus, AC power distribution system, and DC power distribution subsystem CTs and not based on a risk-informed approach. The conditions apply simultaneously, and the more restrictive CT must be met. TR WCAP-15622, Revision 0, states that licensees do not conduct any testing or scheduled maintenance on the vital buses during power operation that would make the bus unavailable. The TR stated that an extension of the current vital AC bus 2-hour CT to 24 hours would not change the scope of work normally performed online.

The CT of 34 hours, proposed to be changed from 16 hours, establishes a limit on the maximum time allowed for any combination of AC and DC electrical power distribution subsystems and AC vital bus being inoperable during any single contiguous occurrence of failing to meet LCO 3.8.9. For example, if the CT of 8 hours for an inoperable AC bus is entered during the CT of 24 hours (proposed to be changed from 2 hours) for an inoperable AC vital bus that is returned to operable status, the LCO may already have been not met for up to the CT of 24 hours for an inoperable AC vital bus. This situation could lead to a total of 32 hours from the initial failure to meet the LCO due to an inoperable AC vital bus, to restore the AC bus to operable status. At this time, the same or another AC vital bus could again become inoperable and an additional CT of 24 hours for the inoperable AC vital bus would be allowed prior to complete restoration of the LCO. This situation could continue indefinitely if not limited. The CT of 34 hours (proposed to be changed from 16 hours) limits the time the plant can alternate between the conditions of an inoperable AC bus, an inoperable DC bus, an inoperable AC vital bus, and some combination of an inoperable AC bus, DC bus, or AC vital bus without meeting the LCO.

No CT was established as part of the licensing basis to limit the time plants can alternate between the condition of an inoperable AC bus, an inoperable DC bus, an inoperable AC vital bus, and some combination of an inoperable AC bus, DC us, or AC vital bus without meeting the LCO. The occurrence of independent random failures of equipment (e.g., the random failure of an AC vital bus, an AC bus, and another failure of an AC vital bus occurring at about the same time) was considered incredible. Thus, an explicit TS CT was not established as part of the licensing bases to limit the time plants could alternate between the condition of an inoperable AC bus, an inoperable DC bus, an inoperable AC vital bus, and some combination of an inoperable AC bus, DC bus, or AC vital bus without meeting the LCO.

No second CT was established in the STS, but the ISTS established a second CT to limit the time a plant can alternate between the condition of an inoperable AC bus, an inoperable

DC bus, an inoperable AC vital bus, and some combination of an inoperable AC bus, DC bus, or AC vital bus without meeting the LCO. The ISTS states that the second CT for an inoperable vital AC bus is the sum of the CTs for the multiple conditions.

Based on this information, the NRC staff concludes that the algebraic sum of: (1) the proposed extended CT for an inoperable vital AC bus and (2) the CT for an inoperable AC bus to determine the second CT for an inoperable vital AC bus is acceptable. The individual CTs would be approved separately, but the second CT would be the sum of the individual CTs.

F.3 Acceptable TS Bases Statements for Second CTs

A discussion on the second CTs for an inoperable DG or vital AC bus is given above. The following addresses acceptable TS Bases statements for these second CTs.

F.3.1 TS 3.8.1 Actions

TR WCAP-15622, Revision 0, proposes (for improved readability and understanding) that the portion of the ISTS Bases relating to the second CT for Required Action A.3 - "[10] days from discovery of failure to meet LCO," should be replaced with the following TS Bases statements:

> “The second Completion Time for Required Action A.3 also establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have not been met for up to [7 days]. This could lead to a total of [10 days], since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable and an additional [7 days] allowed prior to complete restoration of the LCO. This could continue indefinitely if [it is] not limited. The [10] day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. This limits the time the plant can alternate between Conditions A, B, and D (see Completion Time Example 1.3-3). The "AND" connector between the 72 hour and [10] day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.
>
> Tracking the [10] day Completion Time is a requirement for beginning the Completion Time “clock” that is in addition to the normal Completion Time requirements. With respect to the [10] day Completion Time, the “time zero” is specified as beginning at the time LCO 3.8.1 was initially not met instead of at the time Condition A was entered. This results in the requirement, when in this Condition, to track the time elapsed from both the Condition A “time zero,” and the “time zero” when LCO 3.8.1 was initially not met. Refer to Section 1.3, “Completion Times,” for a more detailed discussion of the purpose of the “from discovery of failure to meet the LCO” portion of the Completion Time.”

And similarly for the second CT for Required Action B.4, the ISTS Bases should be replaced with the following TS Bases statements:

"The second Completion Time for Required Action B.4 also establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable, the LCO may already have been not met for up to 72 hours. If the offsite circuit is restored to OPERABLE status within the required 72 hours, this could lead to a total of [10] days, since initial failure to meet the LCO, to restore compliance with the LCO (i.e., restore the DG). The [10] day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. This limits the time the plant can alternate between Conditions A, B, and D (see Completion Time Example 1.3-3). The "AND" connector between the 72 hour and [10] day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

Tracking the [10] day Completion Time is a requirement for beginning the Completion Time "clock" that is in addition to the normal Completion Time requirements. With respect to the [10] day Completion Time, the "time zero" is specified as beginning at the time LCO 3.8.1 was initially not met, instead of at the time Condition B was entered. This results in the requirement, when in this Condition, to track the time elapsed from both the Condition B "time zero" and the "time zero" when LCO 3.8.1 was initially not met. Refer to Section 1.3, "Completion Times," for a more detailed discussion of the purposes of the "from discovery of failure to meet the LCO" portion of the Completion Time."

The NRC staff agrees that the revised wording proposed for inclusion in the ISTS TS 3.8.1 Bases for the second CT - "[10] days from discovery of failure to meet the LCO," - improves the readability and understanding of the required action. The NRC staff, therefore, concludes that the proposed revised wording is acceptable.

F.3.2 LCO 3.8.9

The TR WCAP-15622, Revision 0, proposes (for improved readability and understanding) that the portion of the ISTS Bases relating to the second CT for Required Action A.1 - "[34] hours from discovery of failure to meet LCO" should be replaced with the following TS Bases statements:

"The second Completion Time for Required Action A.1 also establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable (Condition C) and subsequently restored OPERABLE, the LCO may already have not been met for up to 2 hours. This could lead to a total of 10 hours, since initial failure to meet the LCO, to restore the AC distribution system. At this time, a vital bus could become inoperable and an additional [24] hours allowed prior to complete restoration of the LCO, for a total of [34] hours. This could continue indefinitely if not limited.

The [34] hour Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A, B, and C are entered concurrently. The "AND" connector between the 8-hour and [34] hour Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

Tracking the [34] hour Completion Time is a requirement for beginning the Completion Time "clock" that is in addition to the normal Completion Time requirements. With respect to the [34] hour Completion Time, the "time zero" is specified as beginning at the time LCO 3.8.9 was initially not met, instead of at the time Condition A was entered. This results in the requirement, when in this Condition, to track the time elapsed from both the Condition A "time zero" and the "time zero" when LCO 3.8.9 was initially not met. Refer to Section 1.3, "Completion Times," for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time."

The second CTs conveyed by Required Action B.1 should be replaced with the following TS Bases statements:

“The second Completion Time for Required Action B.1 also establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an AC bus is inoperable (Condition A) the LCO may already have been not met for up to 8 hours. If the AC bus is restored to OPERABLE status within the required 8 hours, this could lead to a total of [32] hours, since initial failure to meet the LCO, to restore compliance with the LCO, (i.e., to restore the vital bus). At this time, a DC bus could become inoperable and an additional 2 hours allowed prior to complete restoration of the LCO, for a total of [34] hours. This could continue indefinitely if not limited.

The [34] hour Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A, B, and C are entered concurrently. The "AND" connector between the 2 hour and [34] hour Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

Tracking the [34] hour Completion Time is a requirement for beginning the Completion Time "clock" that is in addition to the normal Completion Time requirements. With respect to the [34] hour Completion Time, the "time zero" is specified as beginning at the time LCO 3.8.9 was initially not met, instead of at the time Condition B was entered. This results in the requirement, when in this Condition, to track the time elapsed from both the Condition B "time zero" and the "time zero" when LCO 3.8.9 was initially not met. Refer to Section 1.3, "Completion Times," for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time."

Similarly, the CTs conveyed by Required Action C.1 should be replaced with the following TS Bases statements:

“The second Completion Time for Required Action C.1 also establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition C is entered while, for instance, an AC bus is inoperable (Condition A) and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This could lead to a total of 10 hours, since initial failure to meet the LCO, to restore the DC distribution system. At this time, a vital bus could become inoperable and an additional [24] hours allowed prior to complete restoration of the LCO, for a total of [34] hours. This could continue indefinitely if not limited.

The [34] hour Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A, B, and C are entered concurrently. The "AND" connector between the 2 hour and [34] hour Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

Tracking the [34] hour Completion Time is a requirement for beginning the Completion Time "clock" that is in addition to the normal Completion Time requirements. With respect to the [34] hour Completion Time, the "time zero" is specified as beginning at the time LCO 3.8.9 was initially not met, instead of at the time Condition C was entered. This results in the requirement, when in this Condition, to track the time elapsed from both the Condition C "time zero" and the "time zero" when LCO 3.8.9 was initially not met. Refer to Section 1.3, "Completion Times," for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time."

The NRC staff agrees that the revised wording proposed for inclusion in the ISTS TS 3.8.9 Bases for the required action - "[34] hours from discovery of failure to meet the LCO," - improves the readability and understanding of the second CT. The NRC staff, therefore, concludes that the proposed revised wording is acceptable.