February 23, 2006

Mr. Christopher M. Crane, President
and Chief Nuclear Officer
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: LASALLE COUNTY STATION, UNITS 1 AND 2 - ISSUANCE OF AMENDMENTS RE: REQUEST TO EXTEND THE COMPLETION TIMES RELATED TO TECHNICAL SPECIFICATIONS ASSOCIATED WITH RESIDUAL HEAT REMOVAL SERVICE WATER (TAC NOS. MC6803 AND MC6804)

Dear Mr. Crane:

The U.S. Nuclear Regulatory Commission (Commission) has issued the enclosed Amendment No. 175 to Facility Operating License No. NPF-11 and Amendment No. 161 to Facility Operating License No. NPF-18 for the LaSalle County Station, Units 1 and 2, respectively. The amendments are in response to your application dated April 13, 2005, as supplemented by letter dated December 22, 2005.

The amendments make changes to the following four Technical Specifications (TSs):

- Extend the completion time (CT) for required action A.1,"Restore Residual Heat Removal Service Water subsystem to OPERABLE status," associated with TS 3.7.1 from 7 days to 10 days. The change will only be used during the upcoming Unit 1 2006 refueling outage.

- Establish a 6-day (for Division 2 core standby cooling system (CSCS) maintenance) or 10-day (for Division 1 CSCS maintenance) CT for TS 3.7.2 when one or more required diesel generator cooling water subsystems(s) are inoperable. The change will only be used during each of the upcoming Unit 1 2006 and Unit 2 2007 refueling outages, and during the subsequent Unit 1 2008 refueling outage.

The NRC staff is granting this amendment request with respect to TS Sections 3.7.1 and 3.7.2 only. In the original submittal, the licensee also requested an extension of the CT for required Action C.4, "Restore required Diesel Generator (DG) to OPERABLE status," associated with TS 3.8.1 from 72 hours to 6 days; and extension of the CT for required Action F.1, "Restore one required Diesel Generator (DG) to OPERABLE status," associated with TS 3.8.1 from 2 hours to 6 days. The NRC staff needs additional information from the licensee in order to complete its review and grant this portion of the amendment request. The staff will address the requests to extend CTs for TS 3.8.1 in a separate safety evaluation and license amendment, if granted.

A copy of the Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

/RA/

Stephen P. Sands, Project Manager
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-373 and 50-374

Enclosures:
1. Amendment No. 175 to NPF-11
2. Amendment No. 161 to NPF-18
3. Safety Evaluation

cc w/encls: See next page

A copy of the Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

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Stephen P. Sands, Project Manager
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EXELON GENERATION COMPANY, LLC

DOCKET NO. 50-373

LASALLE COUNTY STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No.175
License No. NPF-11

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment filed by the Exelon Generation Company, LLC (the licensee), dated April 13, 2005, as supplemented by letter dated December 22, 2005, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations set forth in 10 CFR Chapter I;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the enclosure to this license amendment and paragraph 2.C.(2) of the Facility Operating License No. NPF-11 is hereby amended to read as follows:

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 175, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 30 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA by K.Jabbour for/

Mindy S. Landau, Acting Chief
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications

Date of Issuance: February 23, 2006

EXELON GENERATION COMPANY, LLC

DOCKET NO. 50-374

LASALLE COUNTY STATION, UNIT 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 161
License No. NPF-18

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment filed by the Exelon Generation Company, LLC (the licensee), dated April 13, 2005, as supplemented by letter dated December 22, 2005, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations set forth in 10 CFR Chapter I;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the enclosure to this license amendment and paragraph 2.C.(2) of the Facility Operating License No. NPF-18 is hereby amended to read as follows:

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 161, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 30 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA by K.Jabbour for/

Mindy S. Landau, Acting Chief
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications

Date of Issuance: February 23, 2006

ATTACHMENT TO LICENSE AMENDMENT NOS. 175 AND 161

FACILITY OPERATING LICENSE NOS. NPF-11 AND NPF-18

DOCKET NOS. 50-373 AND 50-374

Replace the following pages of the Appendix “A” Technical Specifications with the enclosed pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
3.7.1-1 to 3.7.1-3	3.7.1-1 to 3.7.1-3
3.7.2-1 to 3.7.2-4	3.7.2-1 to 3.7.2-4

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 175 TO FACILITY OPERATING LICENSE NO. NPF-11

AND AMENDMENT NO. 161 TO FACILITY OPERATING LICENSE NO. NPF-18

EXELON GENERATION COMPANY, LLC

LASALLE COUNTY STATION, UNITS 1 AND 2

DOCKET NOS. 50-373 AND 50-374

1.0 INTRODUCTION

By letter to the Nuclear Regulatory Commission (NRC) dated April 13, 2005, as supplemented by letter dated December 22, 2005, Exelon Generation Company, LLC (the licensee), requested changes to the technical specifications (TSs) for the LaSalle County Station (LaSalle), Units 1 and 2. The supplement dated December 22, 2005, provided additional information that clarified the application, did not expand the scope of the application as initially noticed, and did not change the NRC staff's proposed no significant hazards consideration determination as published in the *Federal Register* on June 7, 2005 (70 FR 33213).

1.1 Proposed License Amendment

The proposed changes would revise, on a temporary basis, TS 3.7.1, "Residual Heat Removal [RHR] Service Water (RHRSW) System," TS 3.7.2, "Diesel Generator [DG] Cooling Water (DGCW) System." Specifically, the proposed changes would revise the completion times (CT) stated in these TS sections as described below:

- Extend the CT for Required Action A.1, "Restore Residual Heat Removal Service Water subsystem to OPERABLE status," associated with TS 3.7.1 from 7 days to 10 days. This proposed change would only be used during the upcoming Unit 1 2006 refueling outage.

- Establish a 6-day (for Division 2 core standby cooling system (CSCS) maintenance) or 10-day (for Division 1 CSCS maintenance) CT for TS 3.7.2 when one or more required DG cooling water subsystems(s) are inoperable. This proposed change will only be used during each of the upcoming Unit 1 2006, and Unit 2 2007 refueling outages, and during the subsequent Unit 1 2008 refueling outage.

The NRC staff is evaluating this amendment request with respect to TS Sections 3.7.1 and 3.7.2 only. In the original submittal, the licensee also requested an extension of the CT for required Action C.4, "Restore required Diesel Generator (DG) to OPERABLE status," associated with TS 3.8.1 from 72 hours to 6 days; and extension of the CT for required Action F.1, "Restore one required Diesel Generator (DG) to OPERABLE status," associated

with TS 3.8.1 from 2 hours to 6 days. The NRC staff needs additional information from the licensee in order to complete its review and grant this portion of the amendment request. The NRC staff will address the requests to extend CTs for TS 3.8.1 in a separate safety evaluation and license amendment, if granted.

Due to long-term wear and corrosion, many valves within the CSCS, which includes the RHRSW system, the DGCW system and the Fuel Pool Emergency Make-up (FC) system, are degraded such that isolation on a specific cooling line may not be adequate to perform maintenance on system components such as the DG coolers, room coolers, and other piping components. The licensee has developed a CSCS reliability improvement program that will replace the current isolation valves with stainless steel valves that are less susceptible to the corrosion wear that the current valves are experiencing. Specifically, isolation valves need to be replaced in the Unit 1 and Unit 2 Division 1 DGCW system, the Unit 1 Division 1 FC system, the Unit 1 Division 2 FC system, the Unit 2 Division 1 FC system, the Unit 2 Division 2 FC system, the Unit 1 Division 2 DGCW system and the Unit 2 Division 2 DGCW system. The licensee plans to replace isolation valves during three refueling outages as described below:

> Division 1 CSCS isolation valves in both units (specifically, ODG007, ODG001, 1E12-F330A, 1E12-F330B, 1DG032, 2DG032, 1FC046A, 1FC040A, and 2FC046A) are scheduled to be replaced during the Unit 1 Refueling Outage 11 (L1R11) scheduled for spring 2006. Other valves within the drained and isolated pipe sections may also be replaced during the scheduled work. Unit 2 is expected to be operating during the L1R11 outage. A blank flange will be installed on the Unit 1 Division 1 CSCS suction header at the intake structure. Mechanical line stops will be installed at appropriate points in the system to isolate the piping sections containing the valves to be replaced. The installation of the mechanical line stops while Unit 2 is operating will require Unit 2 entry into TS 3.7.1 Condition A and TS 3.7.2 Condition A due to inoperability of the Division 1 RHRSW and DGCW subsystems.

The maintenance evolutions to replace CSCS isolation valves are time consuming and include draining portions of the systems involved. Based on historical data and best work practices, completion of the entire evolution for each refueling outage specified cannot be assured with the existing CTs. The licensee believes that replacement of the CSCS isolation valves is a prudent and proactive action. Having the capability to isolate components within the CSCS will enable necessary system maintenance to be performed in the future, thus enhancing the reliability of both units' CSCS and improving overall plant safety.

1.2 Related NRC Activities

This proposed license amendment is not related to or in response to any on-going NRC activities (e.g., generic letters (GL)).

2.0 REGULATORY EVALUATION

2.1 Description of System/Component and Current Requirements

The function of the core standby cooling system-equipment cooling water system (CSCS-ECWS) is to circulate lake water from the ultimate heat sink for cooling of the RHR heat exchangers, DG coolers, CSCS cubicle area cooling coils, RHR pump seal coolers, and

low-pressure core spray (LPCS) pump motor cooling coils. This system also provides a source of emergency makeup water for fuel pool cooling and containment flooding water for post-accident recovery.

The CSCS-ECWS for each unit consists of three independent piping subsystems corresponding to the three essential electrical power supply divisions for each unit. All pumps and strainers are located in the basements of the buildings within watertight cubicles to provide separation between divisions and flood protection. The outdoor CSCS-ECWS piping is buried to provide tornado and missile protection. The CSCS-ECW subsystems take suction from the service water tunnel located in the basement of the Lake Screen House. The service water tunnel is kept full by six inlet lines which connect to the circulating water pump forebays.

Division 1 of each unit includes two RHR service water pumps which supply cooling water to the Division 1 RHR heat exchanger and RHR pump seal cooler. The fuel pool emergency makeup pump in Division 1 of each unit supplies a source of emergency makeup water to the spent fuel pool. Also included in Division 1 of Unit 1 is a DG cooling water pump which supplies cooling water to the Division 1 DG, Unit 1 and 2 LPCS pump motor coolers, and Units 1 and 2 Division 1 CSCS area coolers. Electrical power for operation of these pumps is supplied from Division 1 essential power.

Two RHR service water pumps are also provided in Division 2 of each unit to supply cooling water to the Division 2 RHR heat exchanger and the two Division 2 RHR pump seal coolers. The DG cooling water pump in Division 2 of each unit supplies cooling water to the Division 2 DG and to the Division 2 CSCS area cooler. The Division 2 fuel pool emergency makeup pump provides a redundant source of emergency makeup water to the spent fuel pool and also provides a source of containment flooding water to the RHR system for post-accident recovery. Electrical power for these pumps is supplied from essential Division 2 power.

Both the high pressure core spray (HPCS) DG and the Division 3 CSCS area cooler are supplied with cooling water by the Division 3 HPCS DG cooling water pump. Electrical power for this pump is fed from Division 3 essential power.

Each of the six CSCS divisions across the two units is configured with a separate suction pipe from the service water tunnel. The CSCS discharge pipes are combined into a common discharge for identical divisions of both Units 1 and 2. The discharge pipe outlets at the CSCS cooling pond are located above the normal cooling lake level.

Redundancy is provided by designing the CSCS system as multiple independent subsystems. Separation between subsystems assures that no single failure can affect more than one subsystem. Therefore, assuming a single failure in any subsystem including the subsystem shared between units, two subsystems in each unit will remain unaffected. These two subsystems can supply the minimum required cooling water for safe shutdown of a unit or mitigate the consequences of an accident.

Each engineered safety features (ESF) Division has a DG that serves as an independent onsite power source in the event of the simultaneous occurrence of a total loss-of-offsite-power (LOOP) and a loss of the unit auxiliary power system. The DGs have ample capacity to supply

all power required for the safe shutdown of both units in the event of a total loss of offsite power, a loss-of-coolant accident (LOCA) on one unit concurrent with the shutdown of another unit without a LOCA, or a concurrent shutdown of both units without LOCAs.

The RHR system has three functional modes, each of which contributes towards satisfying the design basis of the system. The different modes of RHR operation include:

1. Shutdown cooling reactor pressure vessel head spray

2. Low pressure coolant injection (LPCI) mode

3. Containment cooling mode (suppression pool cooling and containment spray)

The LPCS system's primary function is to provide LPCS to mitigate the effects of an intermediate and large-break LOCAs.

2.2 Applicable Regulations

The licensee, in Section 5.2 of Enclosure 1 of its submittal, identified regulatory requirements and criteria that are applicable to the systems that are affected by the proposed one-time TS changes. For the TSs, Section 50.36, "Technical Specifications," of Title 10 of the *Code of Federal Regulations* (10 CFR) establishes the regulatory requirements related to the content of TSs. Pursuant to 10 CFR 50.36, TSs include items in the following five specific categories related to station operation: (1) safety limits, limiting safety system settings, and limiting control settings; (2) LCOs; (3) surveillance requirements (SRs); (4) design features; and (5) administrative controls. The rule does not specify the particular requirements to be included in a plant's TSs. As stated in 10 CFR 50.36(c)(2)(I), the "Limiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specifications."

The design of the unit-specific CSCS must satisfy the requirements of 10 CFR 50.36(c)(2)(ii), Criterion 3. These requirements state the following:

> A technical specification limiting condition for operation of a nuclear reactor must be established for each item meeting one or more of the following criteria:
>
> *Criterion 3.* A structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a design basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

General Design Criterion (GDC) 17, "Electric power systems," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50 requires, in part, that nuclear power plants have onsite and offsite electric power systems to permit the functioning of structures, systems, and components (SSC) that are important to safety. The onsite system is required to have sufficient independence, redundancy, and testability to perform its safety function, assuming a single failure. The offsite power system is required to be supplied by two physically

independent circuits that are designed and located so as to minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. In addition, this criterion requires provisions to minimize the probability of losing electric power from the remaining electric power supplies as a result of loss of power from the unit, the offsite transmission network, or the onsite power supplies.

2.3 Applicable Regulatory Criteria/Guidelines

The NRC staff performs its review of risk-informed changes to TS requirements in accordance with the guidance provided by Standard Review Plan (SRP) Chapter 16.1, "Risk-Informed Decision making: Technical Specifications." SRP Chapter 16.1 refers to Regulatory Guide (RG) 1.177, "An Approach for Plant-Specific, Risk-Informed Decision Making: Technical Specifications," as an acceptable approach for assessing proposed risk-informed changes to TS allowed outage times (AOTs). Note that the phrase "completion time" used in the licensee's TS is equivalent to the phrase "allowed outage time" used in RG 1.177 and in this safety evaluation.

The regulatory criteria/guidelines on which the NRC staff based its acceptance are:

- RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," which describes a risk-informed approach acceptable to the NRC for assessing the nature and impact of proposed licensing-basis changes by considering engineering issues and applying risk insights. This regulatory guide also provides risk acceptance guidelines for evaluating the results of such evaluations.

- RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," which describes an acceptable risk-informed approach specifically for assessing proposed TS changes in AOTs. Note that the phrase "completion time" used in the licensee's TS is equivalent to the phrase "allowed outage time" used in RG 1.177.

  This regulatory guide also provides risk acceptance guidelines for evaluating the results of such evaluations.

- RG 1.93, "Availability of Electric Power Sources," provides guidance with respect to operating restrictions if the number of available alternate current sources is less than that required by the LCO.

One acceptable approach to making risk-informed decisions about proposed permanent TS changes is to show that the proposed changes meet five key principles stated in RG 1.174, Section 2 and RG 1.177, Section B:

4. The proposed change meets the current regulations unless it is explicitly related to a requested exemption or rule change.

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

6. The proposed change maintains sufficient safety margins.

7. When proposed changes result in an increase in core damage frequency (CDF) or risk, the increases should be small and consistent with the intent of the Commission's Safety Goal Policy Statement.

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

The first three principles pertain to traditional engineering considerations and are evaluated in Section 3, below; whereas the last two principles involve risk considerations that are included within the scope of this evaluation in Section 3.4. Another traditional engineering consideration that is listed in Sections II.A and III.A of SRP Chapter 16.1, and is addressed in Section 3.1 of this evaluation, is the need for and adequacy of the proposed change.

It should be noted that RG 1.174 and RG 1.177 are directly applicable only to permanent (as opposed to temporary, or "one-time") changes to TS requirements. However, the NRC staff has previously consulted these regulatory guides while making risk-informed decisions about temporary TS changes. In the context of risk-informed decisionmaking about TS changes, the risk acceptance guidelines in RG 1.174 and RG 1.177 are not applied in an overly prescriptive manner; rather, they provide an indication, in numerical terms, of what is considered acceptable. The intent in comparing risk results with the risk acceptance guidelines is to demonstrate, with reasonable assurance, that the fourth key principle has been satisfied.

The remedial actions in the TSs are specified in terms of conditions, required actions, and CTs to complete the required actions. When an LCO is not being met, the CTs specified in the TSs are the amount of time allowed in the TSs for completing the specified LCO required actions. The conditions and required actions specified in the TSs must be acceptable remedial actions for the LCO not being met, and the CTs must be reasonable for completing the required actions.

2.4 Affected TS Requirements

Due to long-term wear and corrosion, many valves within the CSCS are degraded to the point that they must be replaced. As part of the CSCS reliability improvement effort, the licensee is proposing to replace the degraded valves for the Unit 1 and Unit 2 Division 1 DGCW system, the Unit 1 Division 1 FC system, the Unit 1 Division 2 FC system, the Unit 2 Division 1 FC system, the Unit 2 Division 2 FC system, the Unit 1 Division 2 DGCW system, and the Unit 2 Division 2 DGCW system. The licensee is proposing to complete these replacements in three stages to be performed during Unit 1 Refueling Outage 11 (spring 2006), Unit 2 Refueling Outage 11 (spring 2007), and Unit 1 Refueling Outage 12 (spring 2008).

In order to complete the CSCS reliability improvement effort, a blank flange will be installed in the Unit 1, Division 1, CSCS suction line from the service water tunnel, and mechanical line stops will installed at appropriate points in the system to isolate the piping sections containing the valves to be replaced. The unavailability of the CSCS impacts several TSs. Therefore, in order to facilitate the replacement the degraded valves, the licensee has requested a one-time change to extend the AOTs for the affected systems only while the replacement work is underway. The licensee requested that this one-time extension of the AOT be applied to the following TS requirements:

- TS 3.7.1, “Residual Heat Removal Service Water System”
  Condition A. One RHRWS subsystem inoperable.
  Applicable in Modes 1-3; extend CT from 7 days to 10 days
  Change only applicable during Unit 1 2006 Refueling Outage

- TS 3.7.2, “Diesel Generator Cooling Water System”
  Condition A. One DGCW subsystem inoperable.
  Applicable in Modes 1-3; establishment of CT of 6 days for Division 2 CSCS or establishment of CT of 10 days for Division 1 CSCS
  Change only applicable during Unit 1 2006, Unit 2 2007, and Unit 1 2008, Refueling outages.

3.0 TECHNICAL EVALUATION

As discussed above in Section 2.2, this evaluation pertains to the traditional engineering considerations that are referred to in SRP Chapter 16.1 and RG 1.177. In completing this evaluation, the NRC staff considered the information that was provided by the licensee’s amendment request dated April 13, 2005, as supplemented by letter dated December 22, 2005.

3.1 Description of the Proposed Change

The proposed change is described above in Section 2.1. Based on a review of the information that was provided, it is the NRC staff’s conclusion that the proposed change will eliminate the regulatory burden of requiring both LaSalle units to be shutdown during the CSCS valve replacement activity. This consideration is consistent with the objectives of the Commission’s Probabilistic Risk Assessment Policy Statement and it establishes a suitable basis for proposing a risk-informed change to the LaSalle TS requirements.

3.1.1 Justification for Requesting a “One-Time” Change

The NRC tends to discourage the use of one-time changes to TS requirements and expects licensees to propose permanent changes to the extent possible in order to establish TS requirements that best accommodate the needs of operating power reactors while at the same time maintaining reactor safety. The information provided in the licensee’s supplemental letter dated December 22, 2005, indicates that additional “one-time” TS changes should not be needed in the future.

The licensee’s response states that the proposed change was not requested on a permanent basis because it was determined that the current situation has a low probability of recurrence and a permanent change is considered unnecessary. The licensee also states that failure mode is well understood and is being mitigated by the replacement valves that are constructed of material that is less susceptible to the extensive corrosion currently experienced. The existing CTs have proven to be adequate for other necessary maintenance. The licensee stated the current preventive maintenance practices, coupled with the more resilient material of the replacement valves, are expected to preclude future degradation that is currently being experienced.

The NRC staff considered the extent and nature of compensatory measures necessary to minimize exposure to risk and reductions in defense in depth. These considerations make it

difficult to justify the proposed change on a permanent basis, and the NRC staff does not consider this to be a viable option. Therefore, the licensee has adequately justified the need for this proposed TS change for implementation of the planned valve replacements on a one-time basis.

3.2 Traditional Engineering Evaluation

The traditional engineering evaluation presented below addresses the first three key principles of the NRC staff's philosophy of risk-informed decision making: compliance with current regulations, evaluation of safety margins, and evaluation of defense-in-depth.

3.2.1 Compliance with Current Regulations

The licensee does not propose to deviate from existing regulatory requirements and compliance with existing regulations is maintained by the proposed one-time change to the TS requirements. Therefore, with respect to compliance with current regulations, the NRC staff considers the proposed one-time TS change to be acceptable.

3.2.2 Evaluation of Safety Margins

Design basis analyses and system design criteria are not impacted by the proposed change and consequently, safety margins are not affected.

3.2.3 Evaluation of Defense-in-Depth Attributes

The NRC staff has reviewed the information that was provided by the licensee in regards to the defense-in-depth attributes in accordance with the guidance that is specified by RG 1.177 for making risk-informed changes to TS requirements. The NRC staff's evaluation of the defense-in-depth attributes is provided below.

- A reasonable balance among prevention of core damage, prevention of containment failure, and consequence mitigation is preserved.

  The proposed change involves an extension of the current TS AOTs for systems that are impacted by the replacement of valves in the CSCS. The systems that are affected during the valve replacement process are associated with one division at a time, leaving safety equipment in the other divisions fully operable and capable of performing its safety functions. Although Division 2 will be considered inoperable during the Unit 2 2007 and the Unit 1 2008 refueling outages due to the use of non-code line stops, it will remain available to perform its safety functions for the operating unit. The non-code line stops are being designed to the same pressure rating and seismic requirements as the CSCS piping. Consequently, the balance among the prevention of core damage, prevention of containment failure, and consequence mitigation is unaffected by the proposed change.

- Over-reliance on programmatic activities to compensate for weaknesses in plant design is avoided.

  The proposed change involves an extension of the current TS AOTs for systems that are impacted by the valve replacement project. While performing the valve replacement, the licensee has committed to implement certain contingencies in order to provide increased assurance that the operable systems will not be unnecessarily challenged or compromised during the work window. Some of the contingencies that have been identified do include programmatic activities, such as protecting the operable equipment by deferring (to the extent possible) the performance of any maintenance or testing related to the equipment of the operable divisions; maintain plant personnel awareness through pre-job briefings, posted signs, and outage communication bulletins; and posting a qualified fire watch in the Unit 2, Division 2, Essential Switchgear Room. However, because this is a one-time change of limited duration and because these measures are consistent with normal plant practices, the NRC staff considers the programmatic activities to be appropriate and necessary for minimizing the risks involved and for maintaining defense-in-depth.

- System redundancy, independence, and diversity are preserved commensurate with the expected frequency, consequences of challenges to the system, and uncertainties (e.g., no risk outliers).

  On Table 1 of the licensee's submittal, the licensee summarizes the defense in depth assessment of the planned Division 1 CSCS configuration. The table shows that only one division is affected at a time and the other two divisions are still operable. The proposed change causes a temporary loss in redundancy, but the proposed change will not cause reduction of division independence or the diversity of the equipment. The operable safety equipment will continue to be capable of performing the necessary assumed safety functions consistent with accident analysis assumptions. The licensee has committed to implement certain contingencies in order to assure the availability and capability of the required operable equipment. These contingencies include deferring, to the extent possible, the performance of any maintenance or testing related to the protected equipment, barricades to segregate protected equipment, posted signs, and plant personnel awareness through pre-job briefings and outage communication bulletins. Additionally, the NRC staff determined that the frequency of challenges to required safety equipment during the short duration of the CT extension is low.

  Given these considerations, the NRC staff agrees that sufficiently redundant, independent, and diverse capabilities will be maintained for performing critical safety functions during the proposed AOT.

- Defenses against potential common cause failures are preserved, and the potential for the introduction of new common cause failure mechanisms is assessed.

  As discussed in the previous bullet, the licensee has established contingencies to assure the availability and capability of redundant, independent, and diverse means of accomplishing critical safety functions during the proposed AOT. The contingencies include limiting the extent that maintenance can be performed, and posting a qualified

fire watch in the Unit 2, Division 2, Essential Switchgear Room while Division 1 CSCS is inoperable. These contingencies will minimize the likelihood of fires occurring. Based on the information that was provided, the NRC staff finds that the licensee has taken appropriate measures to preserve defenses against potential common-cause failures and the introduction of new common-cause failure mechanisms has been adequately assessed and none have been identified.

- Independence of barriers is not degraded.

  The proposed changes and the valve replacement work does not directly impact the independence of the barriers or otherwise cause them to be degraded. Therefore, the NRC staff finds that the independence of barriers will not be degraded by the proposed AOT or by the valve replacement activities.

- Defenses against human errors are preserved.

  The licensee has established contingencies for assuring that critical safety functions will be maintained during the proposed AOT. The contingencies includes posting signs, providing personnel with outage communication bulletins, and focused operator briefings to assure that operators are fully aware of the plant configuration and actions that may be needed in order to respond to problems that could arise during the proposed AOT for performing the valve replacement activities. Administrative controls have been established to facilitate implementation of these contingency measures. Also, contingencies to control maintenance on protected systems/equipment will help prevent operator distractions from occurring. The NRC staff finds that defenses against human errors will be adequately preserved during the proposed AOT.

- The intent of the GDC in Appendix A to 10 CFR Part 50 is maintained.

  The proposed change does not modify the plant design bases or the design criteria that were applied to SSCs during plant licensing. Consequently, the plant design with respect to the GDC is not affected by the proposed change.

3.3 Risk Evaluation

The key information used in the NRC staff's review of the risk evaluation is contained in Attachment 1 to the licensee's submittal (Reference 1), as supplemented by the licensee in response to the NRC staff's request for additional information (Reference 2). The NRC staff also reviewed the safety evaluation reports (SERs) on the individual plant examination (IPE, Reference 3), the individual plant examination - external events (IPEEE, Reference 4), and three recent risk-informed applications (References 5, 6, and 7).

The licensee performed the Risk Evaluation for Tier 1, "PRA Capability and Insights," Tier 2, "Avoidance of Risk Significant Plant Configuration," and Tier 3, "Risk-informed Configuration Risk Management Program." The NRC staff evaluated the licensee's risk evaluation and finds it to be acceptable.

The risk evaluation presented below addresses the last two key principles of the NRC staff's philosophy of risk-informed decision making, which concern changes in risk and performance

monitoring strategies. The NRC staff evaluated these key principles by using the three-tiered approach described in Chapter 16.1 of the SRP and RG 1.177.

> Tier 1 - The first tier evaluates the licensee's probabilistic risk/safety assessment (PRA/PSA) and the impact of the change on plant operational risk, as expressed by the change in CDF and the change in large early release frequency (LERF). The change in risk is compared against the acceptance guidelines presented in RG 1.174. The first tier also aims to ensure that plant risk does not increase unacceptably during the period when equipment is taken out of service per the proposed license amendment, as expressed by the incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP). The incremental risk is compared against the acceptance guidelines presented in RG 1.177.
>
> Tier 2 - The second tier addresses the need to preclude potentially high-risk plant configurations that could result if equipment other than that associated with the proposed license amendment is taken out of service simultaneously, or if other risk-significant operational factors, such as concurrent system or equipment testing, are also involved. The NRC staff's objective in this part of the review is to ensure that appropriate restrictions on dominant risk-significant plant configurations associated with the CT extension are in place.
>
> Tier 3 - The third tier addresses the licensee's overall configuration risk management program (CRMP) to ensure that other potentially lower probability, but nonetheless risk-significant, configurations resulting from maintenance and other operational activities are identified and compensated for.

3.3.1 Staff Evaluation of Tier 1

The Tier 1 staff review involved two aspects: (1) evaluation of the technical adequacy of the PRA and its application to the proposed CT extension, and (2) evaluation of the PRA results and insights stemming from its application.

3.3.1.1 Evaluation of Probabilistic Risk Assessment (PRA) Technical Adequacy

To determine whether the PRA used in support of the proposed CT extension is of sufficient quality, scope, and level of detail, the NRC staff evaluated the relevant information provided by the licensee in their submittal, as supplemented, and considered the findings of recent PRA reviews. The NRC staff's review of the licensee's submittal focused on the capability of the licensee's PRA model to analyze the risks stemming from the proposed CT extensions and did not involve an in-depth review of the licensee's PRA.

The LaSalle PRA model quantifies the CDF and LERF for accidents initiated by internal initiating events, internal floods, and seismic events. The PRA has evolved from the original IPE and IPEEE conducted to satisfy Generic Letter 88-20, including seven subsequent major revisions. The licensee uses an administratively controlled process to maintain configuration control of the PRA models, data, and software. In addition to model control, the licensee uses administrative mechanisms to assure that plant modifications, procedure changes, calculations, operator training, and system operation changes are appropriately screened, dispositioned, and scheduled for incorporation into the PRA in a timely manner. Specifically, the licensee reviews

plant hardware and procedure changes on an approximate quarterly basis to determine if they impact the PRA and if any PRA model and/or documentation change is warranted. These reviews are formally documented. The licensee maintains a PRA update requirements evaluation (URE) database for PRA implementation tracking. The licensee reviewed the URE database in support of the proposed temporary CT extensions to identify the impact on the supporting risk evaluation of any open (i.e., not yet officially resolved and incorporated into the PRA) UREs. The licensee concluded that the open UREs had only a small impact on the PRA results and conclusions. The NRC staff concludes that the LaSalle PRA adequately represents the as-built, as-operated plant configuration because the licensee uses an administratively controlled process to identify and incorporate plant changes on a periodic basis.

The license does not maintain a current fire PRA. The risk due to internal fires was considered in the IPEEE, which was based upon risk analyses performed under the NRC's Risk Methods Interpretation and Evaluations Program (RMIEP) and the NRC's Phenomenology and Risk Uncertainty Evaluation Program (PRUEP), as documented in NUREG/CR-4832 (Reference 8) and NUREG/CR-5305 (Reference 9).

However, to provide some quantitative context in which to assess the proposed CT impact on plant fire risk, the RMIEP internal fire accident sequences were integrated with the PRA system fault trees and component failure database:

- A fire core damage event tree structure was developed based on the General Transient event tree.

- RMIEP fire damage scenarios representing approximately 97 percent of the RMIEP fire CDF were modeled in CAFTA (the PRA software code) and linked with the fire event tree structure.

- RMIEP-defined fire equipment damage per fire scenario were input into CAFTA via flag files.

- Post-initiator operator action human error probabilities were reviewed and increased where appropriate to account for the additional effects of fire scenarios on operator stress and ex-control room access.

A peer review of the PRA was conducted in 2000, using the March 2000 Nuclear Industry Institute (NEI) draft "Probabilistic Risk Assessment (PRA) Peer Review Process Guidance." All of the Category A and B Facts and Observations (F&Os) generated by the peer review with an impact to affect the risk evaluation of the proposed CT extensions have been resolved. In fact, all but two Category A and B F&Os have been resolved; the two unresolved F&Os concern documentation issues and do not impact the results or conclusions of the risk evaluation.

The licensee conducted a self-assessment of its PRA against the ASME PRA Standard (ASME SA-R-2002) using the guidance in draft RG DG-1122, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities." The NRC staff observes that DG-1122 has been issued as RG 1.200 for trial use. This self-assessment was documented and used as the basis for planning the most recent PRA update. Many of the findings from the self-assessment have been incorporated into the current PRA model. The outstanding findings, which concern documentation enhancements and process issues, were reviewed to ensure that they do not impact the results and conclusions of the risk evaluation developed to support the proposed CT extensions.

In addition to reviewing the original IPE and IPEEE, the NRC staff has considered the technical adequacy of the PRA in three recent risk-informed applications concerning (1) extension of the DG CT, (2) risk-informed inservice inspection, and (3) extension of the surveillance test interval for integrated leak rate testing. In each case, the NRC staff concluded that the PRA was technically adequate to support the application.

Based on review of the above information, the NRC staff finds that the licensee has satisfied the intent of RG 1.177 (Sections 2.3.1, 2.3.2, and 2.3.3), RG 1.174 (Section 2.2.3 and 2.5), and SRP Chapter 16.1, and that the quality of the LaSalle PRA is sufficient to support the risk evaluation provided by the licensee in the proposed license amendment.

3.3.1.2 Evaluation of PRA Results and Insights

As previously discussed, satisfaction of the fourth key principle of risk-informed decisionmaking may be demonstrated with reasonable assurance by comparing risk metrics that reflect the proposed TS change to the numerical risk acceptance guidelines in RG 1.174 and RG 1.177.

In order to assess the impact of the proposed temporary CT extensions on risk, the licensee calculated the risk metrics defined in RG 1.177 (ICCDP and ICLERP). Section 2.4 of RG 1.177 indicates that, in addition to the ICCDP and ICLERP, the licensee should consider the risk metrics defined in RG 1.174 (change in CDF and change in LERF). For a temporary CT extension, the licensee can show that the change in CDF is numerically equal to the ICCDP; a similar relationship exists between the change in LERF and ICLERP. Results of the licensee's calculations are shown in the following tables:

Replacement of Division 1 CSCS Isolation Valves in Both Units To Be Conducted During the Unit 1 Refueling Outage 11 (L1R11) While Unit 2 is Operating				
Risk Contributor	Baseline CDF (/y)	ICCDP	Baseline LERF (/y)	ICLERP
Internal initiating events, internal floods, and seismic events	7×10^{-6}	1×10^{-6}	4×10^{-7}	1×10^{-8}
Internal fires (simplified model)	8×10^{-6}	3×10^{-8}	see text	see text
Total	2×10^{-5}	1×10^{-6}	4×10^{-7}	1×10^{-8}

The results given in the above table credit various compensatory measures that the licensee has proposed to minimize the risk impact of the proposed CT extensions. The specific compensatory measures proposed are discussed further under Section 3.3.2 (Tier 2 evaluation) and Section 4.0 (regulatory commitments).

As previously discussed, the licensee does not maintain a fire PRA model. As a result, it did not calculate risk metrics related to large early release specific to internal fire risk. The licensee developed conditional containment failure probabilities (CCFPs) as a function of core-damage accident types from the internal initiating events PRA model. Assuming that these CCFPs also apply to internal fires, then the contribution of internal fires to the overall LERF and ICLERP is small. The NRC staff concurs with the licensee's approach to considering the fire-related impact on the large early release risk metrics.

The licensee examined the risk from other external events (besides seismic events and internal fires) by reviewing the screening analysis of external events conducted as part of the RMIEP. In this study, with five exceptions, all other external events were screened from further analysis as non-significant contributors to plant risk using the following criteria:

- The event is of equal or lesser damage potential than the events for which the plant is designed, or

- The event has a significantly lower mean frequency of occurrence than other events with similar uncertainties and could not result in worse consequences than those events, or

- The event cannot occur close enough to the plant to affect it, or

- The event is included in the definition of another event, or

- The event is slow in developing and there is sufficient time to eliminate the source of the threat or to provide an adequate response.

The exceptions include aircraft impact, extreme winds and tornadoes, transportation accidents, toxic chemical releases, explosions, turbine generated missiles, and external flooding. The licensee maintained that, based on its review of the RMIEP study, that these external events are negligible contributors to overall plant risk. The NRC staff concurs with the licensee's assessment, and concludes that the proposed CT extensions will not influence the frequency of occurrence of these other external events.

The risk acceptance guidelines in RG 1.177 for ICCDP and ICLERP are 5×10^{-7} and 5×10^{-8}, respectively. The risk metrics calculated for the proposed CT extensions meet these guidelines, with the exception of the ICCDP associated with the replacement of Division 1 CSCS isolation valves in both units. The NRC staff concludes that the risk impact of the proposed CT extensions is acceptable for the following reasons:

- The proposed CT extensions concern a temporary change to the technical specifications. As previously noted, RG 1.177 is directly applicable only to permanent changes to TS requirements.

- The licensee's estimate of the fire risk contribution is conservative. A more realistic calculation would result in smaller ICCDP values.

- The licensee has proposed compensatory measures (refer to the Tier 2 evaluation), particularly measures to minimize the fire-related risks, during the planned maintenance activities.

Therefore, the NRC staff finds that the licensee's first tier risk evaluation, as described in Chapter 16.1 of the SRP and RG 1.177, is acceptable.

3.3.2 Evaluation of Tier 2

The second tier evaluates the capability of the licensee to recognize and avoid risk-significant plant configurations that could result if equipment other than that associated with the proposed license amendment is taken out of service simultaneously, or if other risk-significant operational factors, such as concurrent system or equipment testing, are also involved.

During development of its Tier 1 evaluation of the Division 1 CSCS isolation valve replacements on both units, the licensee identified the need to impose various compensatory measures to reduce the risk associated with the proposed CT extensions. These compensatory measures were credited during calculation of the final Tier 1 risk metrics. The specific compensatory measures to be taken are:

- Restrict concurrent maintenance on Unit 2 Division 2 4kv Bus 242Y;

- Restrict concurrent maintenance on Unit 2 Division 2 EDG;

- Restrict concurrent maintenance on Unit 2 Division 2 Main Battery Charger;

- Restrict concurrent maintenance on Unit 2 Division 2 CSCS;

- Restrict concurrent maintenance on Unit 2 Division 2 RHR;

- Restrict concurrent maintenance on Unit 2 Division 3 HPCS;

- Restrict concurrent maintenance on Unit 2 Motor-Driven Feedwater Pump; and

- Post a qualified fire watch in the Unit 2 Essential Switchgear Room.

Table 4 in Attachment 1 of the licensee's application shows how these compensatory measures were mapped onto specific PRA basic events that describe equipment unavailability due to maintenance. In order to ensure that these compensatory measures are utilized, the licensee has agreed to formal regulatory commitments, as further discussed in Section 4.0.

In addition to the compensatory measures described above, the licensee has stated that the Division 1 CSCS work will be performed with a number of controls in place (consistent with plant procedures and practices) to reduce errors and minimize risk, which are described below:

Prior to Maintenance Work

The following controls will ensure that the maintenance is performed on the proper piping segments and valves, and that the work does not proceed until the system is properly isolated and prepared:

- The work is identified as a "Heightened Level of Awareness (HLA)" job and the draining activity for the piping will require a HLA pre-job brief be conducted. Special procedures governing these activities will be prepared.

- A walkdown and visual inspection will be performed of the valves that need to be closed and those that will be replaced, in accordance with the EGC procedure for clearance and tagging of equipment. This walkdown will be performed by operations personnel knowledgeable of the systems and by supervisory personnel in charge of the personnel performing the maintenance work.

- An EGC procedurally controlled checklist will be used during the pre-job walkdown that specifically lists each of the valves that need to be closed. Additionally, each valve verification will require initialing and verification by a second individual.

- Existing EGC maintenance procedures and special procedures prepared for this specific maintenance, do not allow work to commence until draining has been properly completed and verified.

During the Maintenance Work

The following controls will ensure that inadvertent area flooding does not occur during the maintenance work:

- The special procedures for this work require that the pressure integrity of the piping isolation points be verified prior to making any cuts into the system.

- The mechanical line stops will be administratively controlled in accordance with the EGC equipment clearance process to prevent inadvertent opening or removal of the stops.

- The special procedures for this work require damage control plugs be available should a failure of a line stop occur. The pressure head will be very low and these devices are very effective at stopping or minimizing leaks . The suction sides of the systems affected are in water tight rooms that offer further protection against flood propagation.

Following the Maintenance Work (System Restoration)

The following control will be taken after the maintenance is performed and the piping unisolated to ensure that drain valves that may have been opened during the work have been closed:

- EGC maintenance procedures require similar line-up verifications for post-job system restoration as for the pre-job line-up.

Tier 1 evaluation of the Division 2 CSCS isolation valve replacements on Unit 1 and Unit 2 (to

be performed during separate refueling outages as previously described) did not identify the need for any compensatory measures.

The NRC staff's review of PRA results to identify compensatory measures demonstrates the licensee's ability to recognize and avoid risk-significant plant configurations. Therefore, the NRC staff finds that the licensee's second tier risk evaluation, as described in Chapter 16.1 of the SRP and RG 1.177, is acceptable.

3.4.3 Evaluation of Tier 3

The third tier assesses the licensee's program to ensure that the risk impact of out of service equipment is appropriately evaluated prior to performing any maintenance activity. The need for this third tier stems from the difficulty of identifying all possible risk-significant configurations under the second tier that could ever be encountered.

The licensee has developed a configuration risk management program (CRMP) governed by station procedures, and described by its technical requirements manual (TRM) Section 5.0.e, which ensures that the risk impact of equipment out of service is appropriately evaluated prior to performing any maintenance activity. This program requires an integrated review to uncover risk-significant plant equipment outage configurations in a timely manner both during the work management process and for emergent conditions during normal plant operation. Appropriate consideration is given to equipment unavailability, operational activities such as testing or load dispatching, and weather conditions. The licensee has the capability to perform a configuration dependent assessment of the overall impact on risk of proposed plant configurations prior to, and during, the performance of maintenance activities that remove equipment from service. Risk is re-assessed if an equipment failure/malfunction or emergent condition produces a plant configuration that has not been previously assessed.

The Tier 3 assessment includes the following considerations:

- Maintenance activities that affect redundant and diverse SSCs that provide backup for the same function are minimized.

- The potential for planned activities to cause a plant transient are reviewed and work on SSCs that would be required to mitigate the transient are avoided.

- Work is not normally scheduled that is highly likely to exceed a TS or TRM CT requiring a plant shutdown. For activities that are expected to exceed 50 percent of a TS AOT, compensatory measures and contingency plans are considered to minimize SSC unavailability and maximize SSC reliability.

- For Maintenance Rule (MR) High Risk Significant SSCs, the impact of the planned activity on the unavailability performance criteria is evaluated.

- As a final check, a blended qualitative-quantitative risk assessment is performed to ensure that the activity does not pose any unacceptable risk. This evaluation is performed using the impact on both CDF and LERF, which are determined using a real-time risk monitoring tool.

- The qualitative assessment examines redundant systems used to support critical safety functions, such that a loss of redundancy is highlighted by the real-time risk monitoring tool.

Based on the information provided above, the NRC staff concludes that the licensee's CRMP meets the intent of guidance in Section 2.3.7.2 of RG 1.177. The NRC staff also observes that the proposed CT extensions are temporary, that the specific maintenance configurations involved have been considered in the licensee's Tier 2 evaluation, and that the licensee has committed to implement various compensatory measures that include restrictions on concurrent preventative maintenance. Therefore, the CRMP will be exercised only if emergent conditions evolve that demand immediate corrective maintenance to remedy; such emergent conditions are unlikely to evolve since the licensee's Maintenance Rule program has been effective in preserving high equipment reliability.

Therefore, the NRC staff finds that the licensee's third tier risk evaluation, as described in Chapter 16.1 of the SRP and RG 1.177, is acceptable.

4.0 REGULATORY COMMITMENTS

The following table identifies the regulatory commitments made by the licensee in conjunction with the proposed CT extensions:

Regulatory Commitments	
Regulatory Commitment	Due Date/Event
Additional administrative controls/actions to protect equipment listed on Attachment D of LLP 2005-005 (also given in Table 4 of Reference 1), will be taken in accordance with station risk management procedures while Division 1 CSCS remains inoperable. The administrative actions include physical barricades to segregate protected equipment, posted signs and enhanced plant personnel awareness through pre-job briefings and outage communication bulletins.	Implemented by procedures while Division 1 CSCS remains inoperable during L1R11.
A qualified fire watch will be posted in the Unit 2 Division 2 Essential Switchgear Room.	Implemented by procedures while Division 1 CSCS remains inoperable during L1R11.
Installation of non-code line stops to isolate the Unit 1 portion of the common discharge header from the Unit 2 portion of the header. The non-code line stops are designed to the same pressure rating and seismic requirements as the CSCS piping and will maintain the availability of the online unit's Division 2 CSCS system.	The regulatory commitments for installation of the non-code line stops for L1R12 and L2R11 will be documented by specific procedures for Unit 1 Division 2 and Unit 2 Division 2 CSCS maintenance.

The NRC staff finds that reasonable controls for the implementation and for subsequent evaluation of proposed changes pertaining to the above regulatory commitment(s) are best provided by the licensee's administrative processes, including its commitment management program. The above regulatory commitments do not warrant the creation of license conditions (i.e., items requiring prior NRC approval of subsequent changes).

Based on the above review of defense-in-depth attributes, the NRC staff finds that defense-in-depth will be adequately maintained during the valve replacement activities.

The NRC staff finds that the licensee's proposed, temporary CT extensions are acceptable because the five key principles of risk-informed decision making identified in RG 1.174 and RG 1.177 have been satisfied.

In summary, as discussed above, the NRC staff has evaluated the proposed changes to the CTs for TS 3.7.1 and TS 3.7.2. Based on the above evaluation, which involves risk and deterministic considerations, the NRC staff concludes that it is safe to operate the plant using the proposed CTs and, therefore, the proposed CTs meet 10 CFR 50.36. The NRC staff concludes that the proposed amendments are acceptable.

5.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Illinois State official was notified of the proposed issuance of the amendments. The State official had no comments.

6.0 ENVIRONMENTAL CONSIDERATION

The amendments change a requirement with respect to the installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendments involve no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendments involve no significant hazards consideration, and there has been no public comment on such finding (70 FR 33213; June 7, 2005). Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

7.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

8.0 REFERENCES

1. Letter from Joseph A. Bauer, Exelon Generation Company to U.S. Nuclear Regulatory Commission, "Request for a License Amendment to Extend the Completion Times

Related to Technical Specifications Associated with Residual Heat Removal Service Water, Diesel Generator Cooling Water and the Opposite Unit Division 2 Diesel Generator," RS-05-0011, ADAMS Accession No. ML051040149, April 13, 2005.

2. Letter from Joseph A. Bauer, Exelon Generation Company to U.S. Nuclear Regulatory Commission, "Additional Information Supporting the Request for a License Amendment to Extend the Completion Times Related to Technical Specifications Associated with Residual Heat Removal Service Water, Diesel Generator Cooling Water and the Opposite Unit Division 2 Diesel Generator," RS-05-0172, ADAMS Accession No. ML060030184, December 22, 2005

3. Letter from U.S. Nuclear Regulatory Commission to D.L. Farrar, Commonwealth Edison Company, "Review of Individual Plant Examination Submittal - Internal Events - LaSalle County Nuclear Power Station, Units 1 and 2 (TAC Nos. M74425 and M74426)," March 14, 1996.

4. Letter from U.S. Nuclear Regulatory Commission to Oliver D. Kingsley, Commonwealth Edison Company, "LaSalle County Station, Units 1 and 2, NRC Staff Evaluation of the Individual Plant Examination of External Events (IPEEE) Submittal (TAC Nos. M83634 and M83635)," ADAMS Accession No. ML003776159 , December 8, 2000.

5. Letter from U.S. Nuclear Regulatory Commission to Oliver D. Kingsley, Exelon Generation Company, "LaSalle County Station, Units 1 and 2 - Issuance of Amendments (TAC NOS. MB1224 AND MB1225)," ADAMS Accession No. ML012780141, January 30, 2002.

6. Letter from U.S. Nuclear Regulatory Commission to Oliver D. Kingsley, Exelon Generation Company, "LaSalle County Station, Units 1 and 2 - Relief Request CR-35 (TAC NOS. MB1982 AND MB1983)," ADAMS Accession No. ML013610078, December 27, 2001.

7. Letter from U.S. Nuclear Regulatory Commission to John L. Skolds, Exelon Generation Company, "LaSalle County Station, Units 1 and 2, Issuance of Amendments Re: Integrated Leakage Rate Test Interval (TAC Nos. MB6574 and MB6575)," ADAMS Accession No. ML033010008, November 19, 2003.

8. NUREG/CR-4832, "Analysis of the LaSalle Unit 2 Nuclear Power Plant: Risk Methods Integration and Evaluation Program (RMIEP)," 10 volumes, 1992-1993.

9. NUREG/CR-5305, "Integrated Risk Assessment of the LaSalle Unit 2 Nuclear Power Plant: Phenomenology and Risk Uncertainty Evaluation Program," 3 volumes, 1992-1993.

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