January 30, 2002

Mr. Oliver D. Kingsley, President
Exelon Nuclear
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: LASALLE COUNTY STATION, UNITS 1 AND 2 - ISSUANCE OF AMENDMENTS (TAC NOS. MB1224 AND MB1225)

Dear Mr. Kingsley:

The U.S. Nuclear Regulatory Commission (NRC) has issued the enclosed Amendment No. 150 to Facility Operating License No. NPF-11 and Amendment No. 136 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 February 20, 2001, as supplemented by letters dated July 13, 2001, and December 28, 2001.

The amendments change the Technical Specifications (TS) Section 3.8.1, "A.C. Sources-Operating," to extend to 14 days the allowable completion time for the required actions associated with restoration of an inoperable Division 1 or Division 2 Emergency Diesel Generator. In addition, the amendments change the TS completion time period associated with discovery of failure to meet TS limiting condition of operation 3.8.1 from 10 days to 17 days.

A copy of the safety evaluation (SE) is also enclosed. The Notice of Issuance will be included in the Commission's biweekly Federal Register notice.

Sincerely,

/RA/

William A. Macon, Jr., Project Manager, Section 2
Project Directorate III
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket Nos. 50-373 and 50-374

Enclosures:
1. Amendment No. 150 to NPF-11
2. Amendment No. 136 to NPF-18
3. Safety Evaluation

cc w/encls: See next page

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The amendments change the Technical Specifications (TS) Section 3.8.1, "A.C. Sources-Operating," to extend to 14 days, the allowable completion time for the required actions associated with restoration of an inoperable Division 1 or Division 2 Emergency Diesel Generator. In addition, the amendments change the TS completion time period associated with discovery of failure to meet TS limiting condition of operation 3.8.1 from 10 days to 17 days.

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/
William A. Macon, Jr., Project Manager, Section 2
Project Directorate III
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Office of Nuclear Reactor Regulation

Docket Nos. 50-373 and 50-374

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1. Amendment No. 150 to NPF-11
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cc w/encls: See next page

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EXELON GENERATION COMPANY, LLC

LASALLE COUNTY STATION, UNIT 1

DOCKET NO. 50-373

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 150
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 February 20, 2001, as supplemented on July 13, 2001, and December 28, 2001, 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. 150, 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 60 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Anthony J. Mendiola, Chief, Section 2
Project Directorate III
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications

Date of Issuance: January 30, 2002

EXELON GENERATION COMPANY, LLC

LASALLE COUNTY STATION, UNIT 2

DOCKET NO. 50-374

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 136
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 February 20, 2001, as supplemented on July 13, 2001, and December 28, 2001, 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. 136, 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 60 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Anthony J. Mendiola, Chief, Section 2
Project Directorate III
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications

Date of Issuance: January 30, 2002

ATTACHMENT TO LICENSE AMENDMENT NOS. 150 AND 136

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

DOCKET NOS. 50-373 AND 50-374

Revise the Technical Specifications by removing the pages identified below and inserting the attached pages. The revised pages are identified by amendment number and contain a vertical line indicating the area of change.

REMOVE	INSERT
3.8.1-2	3.8.1-2
3.8.1-3	3.8.1-3
3.8.1-4	3.8.1-4
3.8.1-6	3.8.1-6

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 150 TO FACILITY OPERATING LICENSE NO. NPF-11

AND AMENDMENT NO. 136 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 application dated February 20, 2001, Exelon Generation Company, LLC (Exelon, the licensee), requested changes to the technical specifications (TS) (Appendix A to Facility Operating License Nos. NPF-11 and NPF-18), of the LaSalle County Station (LaSalle), Units 1 and 2. The original application of February 20, 2001, was supplemented by letters from the licensee on July 13, 2001, and December 28, 2001. The proposed changes to TS Section 3.8.1, "A.C. Sources - Operating," would allow an increase in the allowable completion time for the Required Actions associated with restoration of an inoperable Division 1 or Division 2 Emergency Diesel Generator (EDG) from 72 hours to 14 days. In addition, the proposed changes would allow an increase in the TS completion time period associated with discovery of failure to meet TS limiting condition of operation (LCO) 3.8.1 from 10 days to 17 days. These changes would allow for greater flexibility and more efficient planning of EDG maintenance and testing activities during plant operation.

The supplemental letters contained clarifying information and did not change the initial no significant hazards consideration determination and did not expand the scope of the original *Federal Register* notice.

2.0 BACKGROUND

Since the mid-1980s, the Nuclear Regulatory Commission (NRC) has been reviewing and granting improvements to TS that are based, at least in part, on probabilistic risk assessment (PRA) insights. In its final policy statement on TS improvements of July 22, 1993, the NRC stated that it:

> expects that licensees, in preparing their Technical Specification related submittals, will utilize any plant-specific PSA (probabilistic safety assessment)[1] or risk survey and any available literature on risk insights and PSAs. Similarly, the NRC staff will also employ risk insights and PSAs in evaluating Technical

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[1]PSA and PRA are used interchangeably herein.

> Specifications related submittals. Further, as a part of the Commission's ongoing program of improving Technical Specifications, it will continue to consider methods to make better use of risk and reliability information for defining future generic Technical Specification requirements.

The NRC reiterated this point when it issued the revision to 10 CFR Part 50.36, "Technical Specifications," in July 1995. In August 1995, the NRC adopted a final policy statement (60 FR 42622) on the use of PRA methods in nuclear regulatory activities that improve safety decision making and regulatory efficiency. The PRA policy statement included the following points:

- The use of PRA technology should be increased in all regulatory matters to the extent supported by the state-of-the-art in PRA methods and data and in a manner that complements the NRC's deterministic approach and supports the NRC's traditional defense-in-depth philosophy.

- PRA and associated analyses (e.g., sensitivity studies, uncertainty analyses, and importance measures) should be used in regulatory matters, where practical within the bounds of the state-of-the-art, to reduce unnecessary conservatism associated with current regulatory requirements.

- PRA evaluations in support of regulatory decisions should be as realistic as practicable and appropriate supporting data should be publicly available for review.

The LaSalle TS, Section 3.8.1, "A.C. Sources - Operating," specify requirements for the alternating current (AC) electrical power sources. Currently, the TS allow continued plant operation for 72 hours with an inoperable Division 1 or Division 2 EDG, unless Unit 1 or Unit 2 is in MODE 4, "COLD SHUTDOWN," or MODE 5, "REFUELING," in which case continued plant operation of the other operating unit is allowed for 7 days with the Division 1 EDG inoperable. Additionally, TS Section 3.8.1 limits continued plant operation to a maximum of 10 days from discovery of a failure to meet TS LCO 3.8.1.

LaSalle County Station, Units 1 and 2, has five EDGs supplying power to the Division 1, 2, and 3 emergency power buses. Division 1 of each unit is powered by one swing EDG (i.e. EDG 0). Division 2 of each unit is powered by its specific Division 2 EDGs (i.e., EDGs 1A and 2A). Division 2 powers equipment that is common between both units. Therefore, both Division 2 EDGs are required to be operable to satisfy TS operability requirements for Division 2. Division 3 is powered by two independent EDGs (EDGs 1B and 2B). Therefore, the continued operation of each unit is based on the operability of its associated Division 1, 2, and 3 EDGs and the opposite unit's Division 2 EDG. The engineered safety features (ESF) systems powered by any two of the three divisions provide the minimum safety functions necessary to shut down the respective unit and maintain it in a safe shutdown condition.

Offsite power to the LaSalle switchyard is supplied from four 345 kV transmission lines. Two of the transmission lines are in service for Unit 1 and the other two lines are in service for Unit 2. From the switchyard, two electrically and physically separate circuits provide AC power for each unit via the respective unit's assigned System Auxiliary Transformer (SAT) and the other from the SAT of the other unit by cross-tie between the two units. The unit SAT provides the normal source of power to the respective unit’s Division 1, 2, and 3 emergency buses. In the event of a loss of a unit SAT, the respective Division 1 and 2 emergency buses fast transfer to the Unit Auxiliary Transformer (UAT) which is connected to the unit's main generator output. The Division 3 emergency bus has no second offsite source, and will automatically be supplied by the Division 3 EDG after the bus is de-energized. The Division 1 and 2 emergency buses can be manually transferred to the UAT through the unit ties on a dead bus transfer or a live bus transfer if the EDG is supplying power to the bus.

The continued operation of each unit is based on the operability of its associated Division 1, 2, and 3 EDGs and the opposite unit Division 2 EDG. The ESF systems powered by any of two of the three divisions provide the minimum safety functions necessary to shutdown the unit and maintain it in a safe shutdown condition.

In summary, the offsite power system consists of independent transmission lines into the LaSalle switchyard and two independent circuits into each unit. A single loss of an incoming transmission line, switchyard breaker, transmission tower, SAT or circuit into the plant will not result in unavailability of offsite power.

Each EDG will start on emergency bus degraded voltage or under voltage from its associated 4.16kV emergency bus. The Division 1 EDG will start on an emergency core cooling system (ECCS) actuation signal (i.e., reactor vessel low water level or high drywell pressure) from either unit. The Division 2 and 3 EDGs will start on an ECCS actuation signal (i.e., reactor vessel low water level or high drywell pressure) from the respective unit.

Cross-tie breakers between each Division 1 and Division 2 ESF bus and its associated 4.16kV non-safety-related bus may be manually closed, by operator action, in the event of the loss of both UAT and SAT, the normal feeds to the non-safety-related bus. The ESF bus can be used to power certain non-safety-related essential loads that are within the capability of the EDG. The operator may manually synchronize the reserve offsite power source to the ESF bus. Load limits on the cross-tie are controlled in both normal and emergency operating procedures.

Due to the redundancy of each unit's respective ESF divisions and EDGs, the loss of any one of the EDGs, (i.e., the respective unit's associated Division 1, 2, and 3 EDGs or the opposite unit Division 2 EDG) will not prevent the safe shutdown of the respective unit. The total standby power system, including EDGs and electrical power distribution equipment, satisfies the single failure criterion.

LaSalle County Station is able to withstand and recover from a station blackout (SBO) event of 4 hours in accordance with 10 CFR 50.63, "Loss of all alternating current power." For each unit, an SBO occurs as a result of a loss of offsite power in conjunction with a loss of onsite AC power from the respective unit's Division 1 and 2 EDGs, and failure of the cross-tie breaker to the other unit. The Division 3 EDGs are assumed to be available to support the operation of the high-pressure core spray (HPCS) system during an SBO, but are not classified as "Alternate AC" power sources, because Division 3 EDGs do not supply power to safe shutdown loads. Therefore, even though the Division 3 EDGs are available, the LaSalle County Station coping analysis uses the AC independent approach. The proposed changes do not affect the LaSalle County Station SBO analysis.

3.0 EVALUATION

The staff evaluated the licensee's proposed amendment to the TS using traditional engineering analysis, PRA methods, and a review of operating experience. The staff's traditional analysis using deterministic methods evaluated the capabilities of the plant to mitigate design basis events with one Division 1 or Division 2 EDG inoperable. The staff then used insights derived from the use of PRA methods to determine the risk significance of the proposed changes. The results of these evaluations were used in combination by the staff to determine the safety impact of extending the completion time for one inoperable Division 1 or Division 2 EDG.

The primary change to TS Section 3.8.1 is the completion time extension for an inoperable Division 1 or Division 2 EDG. The licensee indicates that implementation of this completion time extension for an inoperable Division 1 or Division 2 EDG will provide the following benefits:

- Allow increased flexibility in the scheduling and performance of EDG preventive maintenance.

- Allow better control and allocation of resources. Allowing on line preventive maintenance, including overhauls, provides the flexibility to focus more quality resources on any required or elected EDG maintenance.

- Avert unplanned plant shutdowns and minimize the potential need for requests for a notice of enforcement discretion. Risks incurred by unexpected plant shutdowns can be comparable to and often exceed those associated with continued power operation.

- Improve EDG availability during shutdown Modes or Conditions. This will reduce the risk associated with EDG maintenance and the synergistic effects on risk due to EDG unavailability occurring at the same time as various other activities and equipment outages that occur during a refueling outage.

- Permit scheduling of EDG overhauls within the requested 14 day completion time extension period.

The licensee has stated that the proposed completion time of 14 days for an inoperable Division 1 or Division 2 EDG is adequate to perform normal preventive EDG inspections and maintenance requiring disassembly of the EDG and to perform post-maintenance and operability tests required to return the EDG to operable status. The licensee indicated it intends to use the proposed 14 day completion time extension for performing a planned major overhaul of a Division 1 or Division 2 EDG at a frequency of no more than once per EDG per operating cycle. In addition to the planned major overhaul of a Division 1 or Division 2 EDG, the licensee indicates it will continue to minimize the time periods to complete other unplanned EDG maintenance that may occur during the operating cycle. Plant configuration changes for planned and unplanned maintenance of the Division 1 and Division 2 EDGs, as well as the maintenance of other equipment having risk significance, is managed by the Configuration Risk Management Program (CRMP). The CRMP helps ensure that these maintenance activities are carried out with no significant increase in the consequences of a severe accident.

3.1 Deterministic Evaluation

The proposed changes to TS Section 3.8.1 increase the length of time an EDG can be out of service during unit operation; however, the system is designed with adequate defense-in-depth philosophy to accomplish the safety functions and prevent release of radioactive material. The LaSalle County Station has diverse power sources available (e.g., EDGs and opposite unit EDGs and SATs) to cope with a loss of the preferred AC power source (i.e., offsite power). In addition, the opposite unit EDG can be temporarily used to compensate for a unit's onsite emergency power source that is not available. The overall availability of the AC power sources to the ESF buses will not be reduced significantly as a result of increased on-line preventive maintenance activities. It is, therefore, acceptable, under controlled conditions, to extend the completion time and perform on-line maintenance intended to maintain the reliability of the onsite emergency power systems.

System redundancy, independence and diversity are maintained commensurate with the expected frequency and consequences of challenges to the system in accordance with current licensee programs and TS requirements. Station procedures will ensure consideration of prevailing conditions, including other equipment out of service, and implementation of compensatory actions to assure adequate defense in depth whenever the EDGs are out of service.

Additionally, the licensee has stated that it intends to take the following actions during the extended EDG allowed outage time (AOT) that can mitigate any increase in risk:

- Availability of the "preferred" and "reserve" offsite power source via SATs and verification of the cross-tie breaker operability prior to voluntary entry into proposed AOT.

- Verification that the dual unit power supplies and the offsite power sources are operable.

- The appropriate Operations personnel will be trained in the use of the cross-tie breaker procedures, and the procedures will be available to the appropriate Operations personnel during proposed EDG extended completion time.

- Voluntary entry into the proposed EDG extended completion time will not be abused by repeated entry into and exit from the TS LCO.

- Implementation of the CRMP, which helps ensure that these extended maintenance activities are carried out with no significant increase in the consequences of a severe accident while any EDG maintenance is performed.

- No scheduling preplanned maintenance when severe weather conditions are expected.

- No elective maintenance will be scheduled within the switchyard that would challenge the SAT connection or offsite power availability during the proposed EDG extended completion time.

3.2 Deterministic Conclusion

The staff finds the proposed change to extend the EDG AOT from the current 72-hours to 14 days to be acceptable. Our conclusion is based on the following: (1) LCO 3.8.1 requires the licensee to perform surveillance to verify the availability of the "preferred" and "reserve" offsite power sources and unit cross-tie and that the opposite unit EDGs and offsite power source are operable upon entry into the AOT, and (2) implementation of the CRMP while an EDG is in an extended completion time satisfies the requirements of 10 CFR 50.65(a)(4). Further, the staff notes that the licensee’s plans preclude testing and maintenance of other electrical systems during extended EDG outages, and that the licensee has made a commitment to scheduling preplanned maintenance only when adverse weather is not expected, which will minimize the impact of the longer AOT.

Also, the staff finds that the proposed change to the TS completion time period associated with discovery of failure to meet TS LCO 3.8.1 from 10 days to 17 days and the proposed changes made to the TS Bases section are governed by the same considerations applicable to the requested EDG AOT and are, therefore, acceptable. The 17-day completion time limits the amount of continuous time a plant can fail to meet LCO 3.8.1 as a result of entry into Action Conditions A, B, or C.

3.3 PRA Evaluation

The staff used a three-tiered approach to evaluate the risk associated with the proposed changes to TS Section 3.8.1. The first tier evaluated the PRA model and the impact of the completion time extensions for the EDGs on plant operational risk. The second tier addressed the need to preclude potentially high risk configurations should additional equipment outages occur during the time when an EDG is out of service. The third tier evaluated the licensee’s CRMP to ensure that the applicable plant configuration will be appropriately assessed from a risk perspective before entering into or during the proposed completion times. Each tier and the associated findings are discussed below.

Tier 1 Evaluation

The licensee used traditional PRA methodology to evaluate the requested completion time extension for Division 1 or Division 2 EDGs. The Tier 1 review of the licensee’s PRA involved three aspects: (i) evaluation of the PRA model and application to the proposed completion time extension, (ii) evaluation of PRA results and insights stemming from the application, and (iii) discussion of the quality of the PRA.

(i) Evaluation of PRA Model and Application to the Completion Time Extension

The staff reviewed the capability of the licensee’s PRA model to analyze the risk stemming from the proposed completion time changes for Division 1 and Division 2 EDGs and did not perform a general review of the LaSalle County Station PRA, which was extensively based on the NRC’s Risk Methods Integration and Evaluation Program (RMIEP) study (NUREG/CR-4832). The RMIEP study and the Phenomenology and Risk Uncertainty Evaluation Program (PRUEP) developed for the NRC a detailed Level 1 and a Level 2/3 analysis of the LaSalle County Station, Unit 2. Although Unit 1 was not analyzed as part of this effort, the results would be very similar.

The PRA model for LaSalle was developed for the IPE that was submitted to the NRC by letter dated April 28, 1994, in response to Generic Letter 88-20, “Individual Plant Examination for Severe Accident Vulnerabilities - 10 CFR 50.54(f).” The NRC staff issued its safety evaluation (SE) for the LaSalle IPE by letter dated March 14, 1996, wherein the NRC staff concluded that the LaSalle IPE submittal met the intent of Generic Letter 88-20. In the SE accompanying this letter, the NRC cited weaknesses in the licensee’s method for both common cause and human reliability analysis in other licensee PRAs reviewed by the staff (i.e., Zion, Dresden, and Quad Cities). The major PRA limitations identified in the NRC safety evaluation report were addressed in subsequent updates to the PRA.

The current review was based on the staff’s previous evaluation of LaSalle under the RMIEP study and the PRUEP, as well as the staff’s evaluation of the licensee’s IPE and individual plant examination of external events (IPEEE) submittals. The staff concludes that the licensee’s PRA results are reasonable, and the scope and depth of the PRA analysis support such a finding. Discussions with the licensee regarding recent data for EDG reliability and availability did not indicate any adverse trends.

(ii) Evaluation of PRA Results and Insights

The licensee recalculated its PRA to determine the effect of extending the completion time from 72 hours to 14 days. Risk-informed support for the proposed changes to the EDG completion time (for either Division 1 or Division 2) is based on PRA calculations performed by the licensee to quantify the change in average core damage frequency (CDF) and average large early release frequency (LERF) resulting from the increased completion time. To determine the effect of the proposed changes with respect to plant risk, the licensee used the guidance provided in Regulatory Guide (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 Decision Making: Technical Specifications."

The licensee performed an evaluation based on the assumption that the full, extended completion time (i.e., 14 days) would be applied once per EDG per refueling cycle, for a total of 42 days in each operating cycle for the site. This is equivalent to 28 days per unit since the Division 1 EDG is shared between the two units. The cycle time is based on the current 18-month fuel cycle (allowing for 30 days planned and unplanned plant outage time) for LaSalle County Station for a net total cycle length of 517.5 operating days. EDG reliability and availability are monitored and evaluated in relation to Maintenance Rule goals to ensure that EDG outage times do not degrade operational safety over time.

The licensee computed the incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP) per the definitions in RG 1.177. The results of the risk evaluation, including the computed ICCDP and ICLERP, were submitted to the staff as follows: the reported base CDF estimate was 6.9×10^{-6} per year for internal events plus seismic events (if the fire PRA results are included, the base case CDF was 3.9×10^{-5} per year) assuming that an augmented piping inspection program for service water piping located in the turbine building is in place; the base LERF estimate was 1.0×10^{-6} per year and does not credit an augmented piping inspection process; the differential CDF was 2.0×10^{-7} per year; the ICCDP was 3.7×10^{-7}; the differential LERF was 2.0×10^{-8} per year; and the ICLERP as 1.2×10^{-8}. If no credit were given for piping inspections reducing the probability of turbine building pipe breaks, risk results for the EDG completion time extension would be slightly higher with the $ICCDP_{EDG\ 0}$ (i.e., the ICCDP when EDG 0 is the failed EDG) equal to $5.8x10^{-7}$ per year, which slightly exceed RG 1.177 guidance. However, in its February 20, and July 13, 2001, letters to the NRC, the licensee stated that the augmented piping inspections will be implemented prior to implementing the proposed changes in the EDG completion times. In addition, the licensee stated the piping inspections and walkdowns of the piping will be controlled under the CRMP such that, as appropriate, the inspection frequencies could be modified based on plant changes or new industry data. The staff finds that credit for the piping inspections is reasonable.

The results of the risk evaluation were compared with risk significance criteria from RG 1.174 for changes in the annual average CDF and LERF and from RG 1.177 for ICCDP and ICLERP. The ICCDP and ICLERP evaluation was based on EDG 0, which provides the limiting values for these risk metrics. The value for the ICCDP (i.e., $3.7x10^{-7}$) is considered small, includes seismic events and internal floods, but excludes fires. A separate licensee analysis in its July 13, 2001, letter to the NRC demonstrated that the effect of EDG completion time extension is negligible on CDF and LERF for fire initiated events. Finally, the value of ICLERP developed by the licensee meets the guidance given in RG 1.177 for a “small” risk.

In determining the values above, the licensee set the PRA quantification truncation limit to $1.0x10^{-11}$ per year for sequence quantification. This is more than five orders of magnitude below the total CDF. The staff finds this an acceptable truncation limit for this risk-informed application.

The licensee also performed an evaluation of the offsite circuit completion time of 72 hours, taking into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a design basis accident during this period. A risk evaluation was performed to estimate the risk impact of having an offsite power source unavailable for 72 hours. The ICCDP and ICLERP was determined by examining the effects of increasing the applicable loss of offsite power (LOOP) and dual unit LOOP (DLOOP) initiating event frequencies that a single offsite power source unavailable would represent. In addition, the conditional probability of a transient initiating event causing a LOOP/DLOOP were confirmed to have negligible impact on the subject risk metrics when an offsite power source was unavailable.

The calculated risk metric results for offsite sources were submitted to the staff as follows: the ICCDP and ICLERP for a LOOP event were $6.3x10^{-12}$ per year, and the ICCDP and ICLERP for a DLOOP event were $5.6x10^{-11}$ per year. The total ICCDP and ICLERP were $6.2x10^{-11}$ per year. The risk evaluation showed that having a single offsite power source unavailable for up to 72 hours is not risk significant. The ICCDP and ICLERP for this situation were several orders of magnitude less than NRC acceptance guidelines given in RG 1.177.

Conservatively, the ICCDP and ICLERP for the offsite power source can be added to the ICCDP and ICLERP values developed for the individual EDGs. For example, the EDG with the highest ICCDP was the Division 1 EDG. It has an ICCDP of $3.7x10^{-7}$ based on 14 days of unavailability. Adding the ICCDP for an offsite source unavailability to the Division 1 EDG unavailability, the total remains $3.7x10^{-7}$. This meets the guidance in RG 1.77 and is consistent with, and bounded by, the risk evaluation performed for the completion time extension for Division 1 or Division 2 EDGs. Therefore, the staff finds that the risk associated with the failure to continuously meet LCO 3.8.1 for 17 days as a result of multiple entries into Action Conditions A, B, or C for both EDG and offsite sources is acceptable.

With regard to plant risk during shutdown conditions, the licensee did not perform a quantitative evaluation of the proposed changes. The licensee expressed its opinion that it is reasonable to conclude that performing EDG overhauls on-line rather than during outages will increase EDG availability during outages. This should reduce shutdown risk by improving the availability of standby AC power sources for shutdown cooling equipment and other equipment needed to mitigate events that may be postulated to occur during shutdown. Based on the licensee's rationale, the staff concurs in this conclusion.

(iii) Quality of the LaSalle County Station, Unit 2 PRA

The LaSalle County Station PRA is developed from the IPE and IPEEE results, which were based on NUREG/CR-4832, "Risk Methods Integration and Evaluation Program Study." The current LaSalle County Station PRA model is a third generation update from the original LaSalle PRA constructed by Sandia National Laboratories for the NRC with the results reported in NUREG/CR-4832.

The latest and most current PRA model used by the licensee for this analysis has also undergone an external peer review from the Nuclear Energy Institute (NEI) Probabilistic Safety Assessment (PSA) Peer Certification Process in early 2000. The Certification Team found the PRA to be sound and adequate for use in regulatory submittals. The team identified a number of areas as needing enhancement (none of which required immediate corrective action, but the peer review group recommended that 15 enhancements should be evaluated at the next periodic update). The licensee examined these recommendations and found that two were important to the overall quality and scope of the PRA. These enhancements involved updating the human reliability analysis and developing an internal flood analysis for the PRA. These enhancements were developed and implemented prior to the evaluation of the EDG completion time assessment.

The licensee stated that it administratively controls the maintenance and configuration control of the LaSalle County Station PRA models, data, and software. In addition to model control, the licensee indicated that administrative mechanisms are in place to assure that plant modifications, procedure changes, calculations, operator training, and system operation changes are appropriately screened, dispositioned, and scheduled for incorporation into the model. The application of this process was reviewed by a Boiling Water Reactor Owners Group Peer Certification Team (peer review) in early 2000. The licensee stated the review was conducted following the NEI 00-02, "NEI Probabilistic Safety Study (PSA) Certification Peer Review Process," using a team of PRA experts. The licensee stated that the peer review found the LaSalle County Station PRA was a sound model and rated all 11 areas reviewed as adequate to support regulatory applications when combined with deterministic insights.

The staff finds that a small incremental increase in CDF estimated for the change in completion time from 72 hours to 14 days is consistent with the credit taken for the system in the PRA modeling, and that the review and updating of the PRA models by the licensee provide reasonable assurance that the models appropriately reflect the equipment and procedural characteristics at the plant.

Tier 2 Evaluation

The Tier 2 review addressed the need to preclude potentially high risk configurations by identifying the need for any additional constraints or compensatory actions that, if implemented, would avoid or reduce the probability of a risk-significant configuration during the time when one EDG is out of service. The licensee did not identify any actions that should be taken beyond those associated with the LaSalle County Station CRMP. The licensee's CRMP was developed in a manner to assess and manage the increase in risk that may result from proposed maintenance activities before performing such activities, as required by the NRC's Maintenance Rule, 10 CFR 50.65.

Tier 3 Evaluation

The licensee stated that it has developed a CRMP for the LaSalle County Station that ensures that the risk impact of equipment out-of-service is appropriately evaluated prior to performing any maintenance activity. This program involves both a probabilistic and deterministic review to uncover risk-significant plant equipment outage configurations in a timely manner both during the work management process and for emergency conditions during normal plant operation. Consideration is given to equipment unavailability, operational activities like testing or load dispatching, and weather conditions.

As applicable to the proposed EDG AOT, the licensee's CRMP achieves the following:

- Maintenance activities that affect redundant and diverse structures, systems and components (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 is avoided.

- Work that is highly likely to exceed a TS or Technical Requirements Manual completion time requiring a plant shutdown is not scheduled. For activities that are expected to exceed 50 percent of a TS allowed outage time, compensatory measures and contingency plans are required to minimize SSC unavailability and maximize SSC reliability.

- For Maintenance Rule High Risk Significant SSCs, the impact of the planned activity on the unavailability performance criteria is monitored and trended.

- As a final check, the licensee performs a risk assessment to ensure that the activity does not pose any unacceptable risk.

- While in the extended EDG completion time, additional elective equipment maintenance or testing, or equipment failure will be evaluated using the CRMP.

The licensee stated that its CRMP is a program used to assess the integrated capability of the plant. The goals of the CRMP are to ensure that risk-significant plant configurations will not be entered for planned maintenance activities, and appropriate actions will be taken should unforeseen events place the plant in a risk significant configuration during the extended EDG completion time. Activities that yield unacceptable results in accordance with evaluation under the CRMP will be avoided. For example:

- The system load dispatcher will be notified in advance that the station is performing onsite emergency AC power source maintenance and be advised of the increased risk of an SBO during this time.

- No work will be performed on the Division 3 HPCS or its associated EDG on either unit during the proposed EDG extended completion time.

- LaSalle County Station will have procedures in place to implement the above compensatory actions prior to entering an extended EDG completion time.

3.4 PRA Conclusion

Based on the foregoing, the staff finds that the completion time for the LaSalle County Station Division 1 and Division 2 EDGs may be extended to 14 days with a small effect on risk. Additionally, the completion time for the corresponding time period associated with discovery of failure to meet TS LCO 3.8.1 may be extended to 17 days with a small effect on risk.

4.0 STATE CONSULTATION

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

5.0 ENVIRONMENTAL CONSIDERATION

This amendment changes a requirement with respect to 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 amendment involves 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 amendment involves no significant hazards consideration and there has been no public comment on such finding (66 FR 15925). Accordingly, the amendment meets 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 amendment.

6.0 CONCLUSION

The staff evaluated the licensee's proposed changes to TS Section 3.8.1 using traditional engineering analysis, PRA methods, and a review of operating experience. The staff's traditional analysis using deterministic methods evaluated the capabilities of the plant to mitigate design basis events with one Division 1 or Division 2 EDG inoperable. The staff then used insights derived from the use of PRA methods to determine the risk significance of the proposed changes. The results of these evaluations were used in combination by the staff to determine the safety impact of extending the completion time for one inoperable Division 1 or Division 2 EDG.

The staff finds that the allowable Completion Time for the Required Actions associated with restoration of an inoperable Division 1 or Division 2 EDG may be extended from 72 hours to 14 days with a small effect on risk and is, therefore, acceptable. In addition, the staff finds that the proposed change to the TS completion time period associated with discovery of failure to meet TS LCO 3.8.1 from 10 days to 17 days is governed by the same risk considerations applicable to the proposed EDG AOT extension and is, therefore, acceptable.

The staff 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 amendment will not be inimical to the common defense and security or to the health and safety of the public.

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