July 24, 2006

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

SUBJECT: QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2 - ISSUANCE OF AMENDMENTS RE: AUTOMATIC OPERATION OF LOAD TAP CHANGERS (TAC NOS. MC9664 AND MC9665)

Dear Mr. Crane:

The Commission has issued the enclosed Amendment No. 232 to Renewed Facility Operating License No. DPR-29 and Amendment No. 228 to Renewed Facility Operating License No. DPR-30 for the Quad Cities Nuclear Power Station, Units 1 and 2, respectively. The amendments are in response to your application dated January 25, 2006, as supplemented on May 17, 2006.

The amendments revise the Quad Cities, Units 1 and 2 licensing basis, as described in the Updated Final Safety Analysis Report, to allow the use of automatic load tap changers to operate in automatic mode on the reserve auxiliary transformers to compensate for potential offsite power voltage fluctuations, in order to ensure that acceptable voltage is maintained for safety related equipment.

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

Sincerely,

/RA/

Maitri Banerjee, Senior Project Manager
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-254 and 50-265

Enclosures:
1. Amendment No. 232 to DPR-29
2. Amendment No. 228 to DPR-30
3. Safety Evaluation

cc w/encls: See next page

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EXELON GENERATION COMPANY, LLC

AND

MIDAMERICAN ENERGY COMPANY

DOCKET NO. 50-254

QUAD CITIES NUCLEAR POWER STATION, UNIT 1

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No.232
License No. DPR-29

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

   A. The application for amendment by Exelon Generation Company, LLC, et al. (the licensee), dated January 25, 2006, as supplemented by letter dated May 17, 2006, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and 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 rules and 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;

   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, by Amendment No. 232, the license is amended to authorize revision to the Updated Final Safety Analysis Report (UFSAR), as set forth in the application dated January 25, 2006, as supplemented by letter dated May 17, 2006. The licensee shall update the UFSAR to incorporate the use of automatic load tap changers to operate in automatic mode on the reserve auxiliary transformers to compensate for potential offsite power voltage fluctuations, as described in the licensee's application dated January 25, 2006, as supplemented by letter dated May 17, 2006, and the NRC staff's safety evaluation attached to this amendment, and shall submit the revised description authorized by this amendment with the next update of the UFSAR.

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. The UFSAR changes shall be implemented in the next periodic update to the UFSAR in accordance with 10 CFR 50.71(e).

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/
Daniel S. Collins, Chief
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Change to the Facility Operating License

Date of Issuance: July 24, 2006

EXELON GENERATION COMPANY, LLC

AND

MIDAMERICAN ENERGY COMPANY

DOCKET NO. 50-265

QUAD CITIES NUCLEAR POWER STATION, UNIT 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 228
License No. DPR-30

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

   A. The application for amendment by Exelon Generation Company, LLC, et al. (the licensee), dated January 25, 2006, as supplemented by letter dated May 17, 2006, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and 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 rules and 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;

   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, by Amendment No. 228, the license is amended to authorize revision to the Updated Final Safety Analysis Report (UFSAR), as set forth in the application dated January 25, 2006, as supplemented by letter dated May 17, 2006. The licensee shall update the UFSAR to incorporate the use of automatic load tap changers to operate in automatic mode on the reserve auxiliary transformers to compensate for potential offsite power voltage fluctuations, as described in the licensee's application dated January 25, 2006, as supplemented by letter dated May 17, 2006, and the NRC staff's safety evaluation attached to this amendment, and shall submit the revised description authorized by this amendment with the next update of the UFSAR.

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. The UFSAR changes shall be implemented in the next periodic update to the UFSAR in accordance with 10 CFR 50.71(e).

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Daniel S. Collins, Chief
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Change to the Facility Operating License

Date of Issuance: July 24, 2006

ATTACHMENT TO LICENSE AMENDMENT NOS. 232 AND 228

RENEWED FACILITY OPERATING LICENSES NOS. DPR-29 AND DPR-30

DOCKET NOS. 50-254 AND 50-265

Replace the following pages of the Facility Operating Licenses with the attached pages. The revised pages are identified by number and contain marginal lines indicating the areas of change.

Remove	Insert
Unit 1 License Page 4	Unit 1 License Page 4
Unit 2 License Page 4	Unit 2 License Page 4

B. Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 232, are hereby incorporated into this renewed operating license. The licensee shall operate the facility in accordance with the Technical Specifications.

C. The licensee shall maintain the commitments made in response to the March 14, 1983, NUREG-0737 Order, subject to the following provision:

The licensee may make changes to commitments made in response to the March 14, 1983, NUREG-0737 Oder without prior approval of the Commission as long as the change would be permitted without NRC approval, pursuant to the requirements of 10 CFR 50.59. Consistent with this regulation, if the change results in an Unreviewed Safety Question, a license amendment shall be submitted to the NRC staff for review and approval prior to implementation of the change.

D. Equalizer Valve Restriction

Three of the four valves in the equalizer piping between the recirculation loops shall be closed at all times during reactor operation with one bypass valve open to allow for thermal expansion of water.

E. The licensee shall fully implement and maintain in effect all provisions of the Commission-approved physical security, training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822), and the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The combined sets of plans[1], which contain Safeguards Information protected under 10 CFR 73.21, is entitled: "Quad Cities Nuclear Power Station Security Plan, Training and Qualification Plan, and Safeguards Contingency Plan, Revision 0," submitted by letter dated October 21, 2004.

F. The licensee shall implement and maintain in effect all provisions of the approved fire protection program as described in the Updated Final Safety Analysis Report for the facility and as approved in the Safety Evaluation Reports dated July 27, 1979 with supplements dated November 5, 1980, and

[1] The Training and Qualification Plan and Safeguards Contingency Plan are Appendices to the Security Plan.

B. Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No.228, are hereby incorporated into this renewed operating license. The licensee shall operate the facility in accordance with the Technical Specifications.

C. The license shall maintain the commitments made in response to the March 14, 1983, NUREG-0737 Order, subject to the following provision:

> The licensee may make changes to commitments made in response to the March 14, 1983, NUREG-0737 Order without prior approval of the Commission as long as the change would be permitted without NRC approval, pursuant to the requirements of 10 CFR 50.59. Consistent with this regulation, if the change results in an Unreviewed Safety Question, a license amendment shall be submitted to the NRC staff for review and approval prior to implementation of the change.

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[1] The Training and Qualification Plan and Safeguards Contingency Plan are Appendices to the Security Plan.

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION RELATED

TO AMENDMENT NO. 232 TO RENEWED FACILITY OPERATING LICENSE NO. DPR-29

AND AMENDMENT NO. 228 TO RENEWED FACILITY OPERATING LICENSE NO. DPR-30

EXELON GENERATION COMPANY, LLC

AND

MIDAMERICAN ENERGY COMPANY

QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2

DOCKET NOS. 50-254 AND 50-265

1.0 INTRODUCTION

By letter to the Nuclear Regulatory Commission (NRC, the Commission) dated January 25, 2006 (Agencywide Documents Access and Management System (ADAMS) Accession Number ML060310402), as supplemented by letter dated May 17, 2006, (ADAMS Accession Number ML061380550), Exelon Generation Company, LLC, et al. (the licensee) requested changes to the licensing basis for the Quad Cities Nuclear Power Station (Quad Cities), Units 1 and 2. The May 17, 2006, supplement contained clarifying information and did not change the NRC staff's initial proposed finding of no significant hazards consideration.

The proposed changes would revise the Updated Final Safety Analysis Report (UFSAR), to allow the use of automatic load tap changers (LTCs) to operate in automatic mode on the reserve auxiliary transformers (RATs) to compensate for potential offsite power voltage fluctuations, in order to ensure that acceptable voltage is maintained for safety-related equipment. Installation of an RAT with automatic LTC features was planned for Quad Cities, Unit 2 during the spring 2006 refueling outage and for Quad Cities, Unit 1 during the spring 2007 refueling outage. However the licensee expedited the installation schedule such that the automatic LTC feature was installed in both units by June 2006. The licensee requested the NRC staff's approval to operate the LTCs in automatic mode. Both LTCs will be operated only in manual mode, which does not require prior NRC staff approval in accordance Title 10 of the *Code of Federal Regulations,* Section 50.59, "Changes, tests, and experiments," until the proposed changes are approved. Once the proposed changes are approved, operation of the LTCs in automatic mode will be allowed and the UFSAR description of the offsite source will be revised to describe the automatic LTC operation. Operation of the LTCs in automatic mode requires the NRC staff's approval in accordance with 10 CFR 50.59, since automatic LTC operation could create the possibility for a malfunction of structures, systems, or components important to safety with a different result than any previously evaluated in the UFSAR.

2.0 REGULATORY REQUIREMENTS

The regulatory requirements which the NRC staff applied in its review of the application include:

Appendix A to 10 CFR Part 50, General Design Criteria (GDC) 17, "Electric power systems," requires, in part, that nuclear power plants have an onsite and offsite electric power system to permit the functioning of structures, systems and components important to safety. The onsite system is required to have sufficient independence, redundancy and testability to perform its safety function, assuming a single failure, and the offsite system is required to be supplied by two physically independent circuits. In addition, this criterion requires provisions to minimize the probability of losing electric power from the remaining electric power supplies as the result of loss of power from the unit, the offsite transmission network, or the onsite power supplies.

Appendix A to 10 CFR Part 50, GDC 18, "Inspection and testing of electric power systems," requires that electric power systems that are important to safety be designed to permit appropriate periodic inspection and testing.

In accordance with 10 CFR 50.59 licensees are allowed to make changes to the plant as described in the UFSAR without obtaining a license amendment only if certain criteria are met. One of these criteria is that the changes do not result in a different malfunction of a structure, system, or component important to safety than previously evaluated in the UFSAR.

3.0 TECHNICAL EVALUATION

3.1 Background

At Quad Cities, Units 1 and 2, power to safety-related equipment is provided by two divisions of 4160 V essential service system (ESS) buses. For each unit, one division of the ESS buses is normally powered by the unit auxiliary transformer (UAT), which receives its power from the main generator of the unit, and the other division is normally powered by the RAT, which receives its power from the offsite transmission system. If power from the UAT is lost, the source of power to the ESS buses is transferred to the RAT. To maintain operability of the offsite power circuits, the minimum required switchyard voltage is approximately 352.9 KiloVolts (kV) for Quad Cities, Unit 1 and approximately 351 kV for Quad Cities, Unit 2. These minimum required voltages ensure that the voltage is adequate at the ESS buses, under accident loading conditions. The loss of power (LOP) instrumentation monitors the ESS buses. If insufficient voltage is available, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) electrical power sources.

Prior to June 1, 2004, the transmission system operator for Quad Cities, Units 1 and 2, Exelon Energy Delivery (EED), maintained a system planning operation guide (SPOG) 2-1 that provided expected actual switchyard voltages at the nuclear stations, based on a set of operational contingencies and studies of projected load growth. SPOG 2-1 stated that the expected voltage would be maintained between approximately 103 percent and 105 percent of the nominal voltage on the 345 kV system, or 354.1 kV to 362.3 kV. The expected minimum switchyard voltage in SPOG 2-1 did not bound every possible combination of transmission system contingencies. Due to unforeseen changes in generation and load patterns, the actual minimum voltage may have been lower than the expected voltage. A state estimator was used with contingency analysis applications to monitor real-time grid conditions and to determine the predicted switchyard voltage following a trip of one of the Quad Cities units.

On June 1, 2004, the EED transmission system became part of the Pennsylvania, New Jersey, Maryland (PJM) interconnected network. For transmission planning purposes under the PJM interconnected network, EED maintains transmission system planning criteria to set the maximum voltage and the expected minimum voltage for the transmission system. The transmission system planning criteria switchyard voltage range is 98 percent to 105 percent of the nominal 345 kV (i.e., 338.1 kV to 362.3 kV). The expected minimum voltage is based on expected system loading with both units offline at two unit sites with the included impact of the loss of reactive power support. Dual unit sites are analyzed with the loss of the unit assuming accident loading concurrent with the worst-case additional contingency.

The PJM interconnected network has also set emergency transmission system voltage criteria to respond to extreme grid conditions that may cause the voltage on the 345 kV transmission system to drop below 98 percent of nominal. These criteria state that every effort, including reduction of system loads, will be made to maintain the 345 kV transmission system voltage above 95 percent of nominal.

The minimum expected voltage in SPOG 2-1 for the 345 kV transmission system (i.e., 103 percent of nominal) met the Quad Cities requirements for operability of offsite power. However, following the transfer to the PJM interconnected network, the minimum transmission planning criteria voltage (i.e., 98 percent of nominal) and the minimum emergency criteria voltages (i.e., 95 percent of nominal) do not meet the Quad Cities requirements for operability. A state estimator was used at Quad Cities, Units 1 and 2, to monitor real-time grid conditions and to determine predicted switchyard voltages following a trip of one of the Quad Cities units. Since the spring of 2004, the state estimator has generated frequent alarms for Quad Cities, Units 1 and 2, indicating that the predicted post-trip voltage was below the minimum required to ensure the operability of the offsite power sources. In each case, Quad Cities and EED took compensatory actions such as reducing the Quad Cities auxiliary loads and/or increasing voltage support from other units to restore the operability of the offsite circuits. In response to these conditions, the licensee initiated actions to procure a replacement for RATs that are equipped with an LTC and to seek the NRC staff's approval to use the LTCs in automatic mode. The LTCs will regulate the voltage supplied to the ESS buses to compensate for variations in the transmission system voltage. The use of LTCs in automatic operation will allow the operability of the offsite power circuits at Quad Cities to be maintained over the range of voltage specified in the transmission planning criteria and emergency criteria (i.e., 95 percent to 105 percent of nominal).

3.2 NRC Staff Evaluation

The proposed UFSAR change adds a discussion of the automatic operation of the LTCs. For Quad Cities, Units 1 and 2, the existing RATs (i.e., transformer TR 12 and TR 22, respectively) were upgraded with slightly larger capacity transformers that feature an LTC to regulate voltage on the safety-related buses. The RATs provide offsite power from the 345 kV transmission system.

The licensee proposed a change to the Quad Cities UFSAR, Section 8.3.1.2.2.1, "Reserve Auxiliary Transformer," to reflect the incorporation of the new RATs and associated LTCs.

The licensee stated that the tap changer mechanism for the LTCs for both transformers is located in a separate enclosure attached to the transformers. The LTC has two modes of operation, automatic and manual. A drive motor rotates the tap changer to increase or decrease the number of transformer windings in service. When operating in its automatic mode, the LTC controller raises and lowers voltage by operating the drive motor. The LTC controller monitors the load and source voltage to create an "error" signal based on sensed secondary voltage, which changes the tap setting when required so that voltage is controlled within the desired range. The tap changer controller uses a primary and a backup LTC controller with a self-testing watchdog system to select the properly functioning controller. A light-emitting diode indicator on the controller serves as a display to verify "CPU OK" status, indicated locally on the control panel on the transformer. The tap changer can also be operated in a manual control mode using the drive motor to rotate the tap changer.

The LTC will provide a range of -5 percent to +25 percent of the rated voltage in 32 steps, each step being 0.938 percent of the rated voltage. Thus, the tap changer is expected to be able to compensate for the expected switchyard voltage range of 95 percent to 105 percent of nominal voltage. The licensee stated that by providing automatic adjustment of the voltage to the Quad Cities auxiliary power system from the offsite 345 kV transmission system, the TR 12 and TR 22 LTCs will compensate for a wide range of 345 kV transmission system operating voltages in the future.

The licensee stated that the regulating relays controlling the LTCs are set with an initial delay of one second (i.e., the voltage must be out of band for one second before the controls initiate a tap change). Once given a signal to change taps, either manually or automatically, the tap changer will complete a tap change in two seconds.

In the event of a voltage dip with no accident signal present, the second-level degraded voltage relay scheme includes a nominal 5-minute timer to allow the voltage to recover before the safety buses are disconnected from offsite power. The 5-minute timer allows adequate time to complete needed tap changes to correct the transient before disconnecting from offsite power.

In the event of a voltage dip concurrent with an accident, the second-level degraded voltage relays are set with a nominal time delay of 7 seconds before which if the voltage does not recover, the safety buses will be disconnected from offsite power. If a loss-of-coolant accident were to occur at full-power operations and the switchyard voltage dipped to the minimum value, it has been determined that two tap changes are required to support the additional continuous load on the transformer. Considering the additional time needed for the 1-second initial delay before the two tap changes begin, the LTC will complete the voltage correction in 5 seconds. The allowable value for the nominal 7-second degraded voltage time delay is greater than 5.7 seconds and less than 8.3 seconds, as specified in Technical Specification (TS) Table 3.3.8.1-1, "Loss of Power Instrumentation." Therefore, the LTC will be successful in preventing a trip of the degraded voltage relays in the event of a voltage dip, precluding unnecessary disconnection of the safety buses from offsite power.

Following installation, each transformer will be subject to standard transformer tests during its acceptance testing. These tests include Doble/sweep frequency response, transformer through-fault, core ground, turns ratio on all taps, low-voltage excitation, winding megger, and alternating current impedance testing. Also, operation of the LTC on each transformer was verified over the full range of tap positions. Testing of the main and backup controllers included verifying with a simulated voltage input that the LTC regulating relay provides the correct raise/lower response and the LTC backup relay provides the proper blocking function.

The licensee has evaluated the potential failure modes of the LTC and its control system. The most severe potential malfunction would be a failure of the primary controller that causes transformer output voltage to rapidly increase or decrease. The backup controller will prevent a defective LTC control from running the voltage outside the established upper and lower limits by blocking the raise-and-lower logic of the tap changer. The backup control will also lower the voltage (i.e., lower the tap position) if the regulated voltage remains above the upper voltage limit for a set period of time. The design also allows the operator to override both LTC controllers, taking manual control if necessary. The licensee has stated that it has obtained current data from the manufacturer on the predicted mean time between failure rates of the controllers. For the primary controller, the predicted mean time between failures is 145 years, and for the backup controller, the predicted mean time between failures is 542 years. The failure data is based on figures as current as of September 30, 2004. Thus, the licensee evaluated that simultaneous failure of both controllers is unlikely.

In the unlikely event that a failure of both the primary and backup controllers results in rapidly increasing voltage, operators can take manual action from the RAT control cabinet to prevent damage to safety-related equipment. The 4160 volt (V) ESS buses are equipped with a process computer alarm that indicates an over-voltage condition has occurred. The computer alarm setpoint is established at 4300 V, which is conservatively below the 110 percent voltage rating of the safety-related motors fed from the bus, consistent with American National Standards Institute/National Electrical Manufacturers Association (ANSI/NEMA) Standard MG-1-2003, “Motors and Generators.” Damage from an over-voltage condition is only expected if the condition is sustained. At a voltage below 4400 V, there is no possibility of causing an over-voltage on 4000 V motors, since this is within the 110 percent NEMA criterion. At voltage below 4300 V on the ESS bus, there is a minimal possibility of creating an over-voltage on a 460 V motor that is fed from a 480 V bus tied to the ESS bus. As load on the 480 V system increases, the actual voltage on the high side (4160 V) of the unit substation transformer will decrease due to the impedance of the transformer. Operators respond by following the guidance of established abnormal operating procedures upon receipt of the 4160 V ESS bus over-voltage alarm. The procedural guidance directs the operator to take manual control over the LTC. The tap setting can be manually lowered to correct bus voltage. Thus, the existing over-voltage alarm, in conjunction with the procedurally controlled operator’s actions to promptly correct the condition, will limit the duration of any over-voltage condition in the unlikely event of a primary and backup controller failure that results in rapidly increasing voltage.

An LTC failure that results in rapidly decreasing voltage could initiate the 5-minute timer on the 4160 V ESS bus degraded voltage relays if the voltage decreased to the current TS setpoint (3948 V - 3885 V). Failure to restore the bus voltage within 5 minutes would cause the power source for these buses to transfer to the emergency DGs. A loss of offsite power is analyzed in the UFSAR. The licensee stated that the presence of the backup controller makes this failure extremely unlikely, and a low-voltage alarm at 3900 V alerts operators to take procedurally guided action prior to reaching the degraded voltage relay setpoint.

The licensee identified other LTC failure modes or malfunctions that could lead to an over-voltage or under-voltage condition or cause the tap changer to fail to change the tap setting when expected (i.e., the tap setting remains “as is”). These malfunctions can result from a failure of the drive motor (including a LOP to the drive motor) when the LTC is operating in either the automatic or the manual mode. In either case, an over-voltage (or an under-voltage) condition could be created if the transmission system voltage changed subsequent to the failure. For example, if the failure occurred during the afternoon on a hot summer day when the load demand was high, a high tap setting could lead to a high-voltage condition in the evening when the system load demand diminished and the grid voltage increased. Failures of the tap changer to change settings when demanded are less serious than active failures of the LTC, since the over-voltage or undervoltage condition would evolve relatively slowly and the magnitude of the resultant change in voltage would be limited to the effect of the change in grid voltage. As noted previously, alarms alert the operator to high-voltage conditions on the 4160 V ESS buses, and procedures are in place to instruct the operators to take action to mitigate or correct the condition. The licensee has stated that its first action is to contact the transmission system operator and request that the voltage be increased or decreased as needed. Further actions include either securing/preventing the start of loads, or adding additional loads based on the scenario. The operator can also manually change the tap setting if required.

Similar LTC transformers are in use at other NRC-licensed facilities. The licensee performed an operating experience review on load tap changer issues at nuclear power plants. The licensee identified only two instances of an LTC controller spuriously running voltage to an extreme value. There are isolated reports of the tap changer failing as-is. There were no documented instances of equipment failures resulting from LTC failure. Given the number of licensed units employing transformers with automatic LTCs and the period of time in operation, it is reasonable to conclude that the few issues identified in the operating experience search do not constitute an equipment reliability issue.

The licensee stated that implementation of automatic operation of the LTCs will compensate for variations in switchyard voltage that could otherwise render the offsite circuits inoperable. In the event the LTC is nonfunctional and unable to compensate for switchyard voltage variations, offsite circuit operability will be determined based on whether the actual and predicted post-trip voltage at the switchyard is adequate to prevent the LOP instrumentation from transferring the ESS bus source to the DGs.

In response to the NRC staff’s request for additional information (RAI) regarding periodic testing to be performed on the LTC, the licensee’s May 17, 2006, letter stated that on a 2-year frequency, the LTC will be verified both manually and electrically for proper timing and sequencing of operation. On a 6-year frequency, preventive maintenance consisting of inspection of contacts for damage and pitting, checks for loose or damaged components, and functional testing of the LTCs (i.e., similar to the 2-year test) will be performed. The NRC staff finds the licensee’s response acceptable.

In response to the NRC staff’s RAI regarding control and indication of LTC in the control room, the licensee’s May 17, 2006, letter stated that there will be no LTC control or tap position indication available in the control room. All manual tap changes will be performed locally at the transformers' LTC control cabinets. Control room operators, however, do have both high and low voltage alarms for the buses that are fed by the RATs. Actual bus voltages can be obtained from voltmeters on the control room panels or through computer points via the plant's process computer. In addition, the primary and backup LTC controllers initiate control room alarms when the micro controllers or power supplies fail. The backup LTC controller also provides a control room alarm when the transformer secondary voltage moves outside the limits of both the primary and backup LTC controllers for a period of 3 minutes. This would alert control room operators that a problem has occurred and the LTC controllers or the LTC itself is not operating properly. LTC control and indication in the control room were deemed unnecessary due to the consequences associated with a postulated failure of the LTC in its automatic mode of operation as discussed before. The NRC staff finds the licensee's response acceptable.

In response to the NRC staff's RAI regarding design features of the LTC to identify failures and limit failure duration, the licensee's May 17, 2006, letter stated that the primary LTC controller is designed to regulate the 4 kV bus voltages under both normal and accident conditions. In the event the LTC controller fails and the voltage rises or falls outside the operating voltage band, the backup LTC controller will take over automatic operation of the LTC. The backup LTC controller also utilizes a redundant relaying scheme to ensure the LTC does not raise or lower the taps beyond the limits set within the backup LTC controller itself. Additionally, both the primary and backup LTC controllers initiate control room annunciator alarms if the micro controllers or power supplies fail. The backup LTC controller provides a control room alarm if the RAT secondary voltage moves outside the limits of both the primary and backup LTC controllers for a period of 3 minutes. Furthermore, the LTC is equipped with a vacuum interrupter monitoring system to ensure the vacuum interrupters are operating properly during the tap change process. The monitoring system will abort a tap change operation if a vacuum interrupter fails to interrupt the current during a tap change or if the power supply to the monitoring system fails. The failure would be indicated on the local control panel and identified during operator rounds. The system must be verified to be operating correctly and manually reset, prior to further tap changes. The NRC staff finds the licensee's response acceptable.

In response to the NRC staff's RAI regarding separate power supply for main and backup controllers associated with the LTC, the licensee's May 17, 2006, letter stated that both the main and backup controllers, as well as the LTC motor and its associated controls, are fed from the same power source via an automatic transfer switch. The normal power supply is from a motor control center (MCC) on the opposite unit. If that source should fail, the transfer switch will automatically swap over power to the LTC and its controllers from an MCC on the affected unit (i.e., emergency supply). The use of the opposite unit MCC was necessary due to the large voltage drop that would occur during accident conditions due to emergency core cooling system (ECCS) pumps starts, which might prevent the LTC motor from operating during the first few seconds of an accident. The LTC will not be considered functional when powered by its emergency power supply. In the event the transfer switch operates, an annunciator alarm is received in the main control room. In response to this alarm, an operator will be dispatched to the transfer switch to verify proper transfer of the power supply and actions will be taken to restore power back from the normal supply. The NRC staff finds the licensee's response acceptable.

The NRC staff agrees that, given the various features incorporated into the LTC design and the expected reliability of the key features (i.e., primary controllers and backup controllers), the likelihood that an over-voltage will create a safety problem should be low. The NRC staff agrees with the licensee that the testing demonstrates continuing compliance with GDC 18.

Based on the information provided by the licensee, the NRC staff concludes that the proposed modification to replace the existing transformers with new transformers having a larger capacity and an automatic LTC and the associated changes to the UFSAR are acceptable.

The proposed design change would accommodate higher and lower voltage than previously allowed from the 345 kV system as the RAT regulates voltage to the plant auxiliary system. Since the RAT LTC also incorporates a backup control unit, the proposed design would reduce the probability of a malfunction of the LTC controller. Implementation of automatic LTC operation would ensure that the voltage provided by the transmission system is adequate to maintain operability of the offsite power sources for the expected range of switchyard voltage and satisfies the requirement of GDC 17.

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

The amendments change the requirements with respect to installation or use of a facility's 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 (71 FR 29678; May 23, 2006). 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.

6.0 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.

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