Union Electric

One Ameren Plaza
1901 Chouteau Avenue
PO Box 66149
St. Louis, MO 63166-6149
314.621.3222

December 19, 2003

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Mail Stop P1-137
Washington, DC 20555-0001

Ladies and Gentlemen: ULNRC-04909

DOCKET NO. 50-483
UNION ELECTRIC COMPANY
CALLAWAY PLANT
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION
REGARDING LICENSE AMENDMENT REQUEST OL-1228
(REVISION TO TECHNICAL SPECIFICATION
SURVEILLANCE REQUIREMENTS 3.8.1 AND 3.8.4)

1) AmerenUE Letter ULNRC-04837, "License Amendment Request OL-1228 – Revision to Technical Specification Surveillance Requirements 3.8.1 and 3.8.4," from D. Shafer (AmerenUE) to USNRC, dated June 6, 2003

2) USNRC Letter, "Request for Additional Information re: Technical Specifications 3.8.1 and 3.8.4 for Callaway, Diablo Canyon, Palo Verde, and Wolf Creek Plants," from J. Donahew (USNRC) to G. Randolph, AmerenUE; G. Rueger, Pacific Gas and Electric; G. Overbeck, Arizona Public Service Company, and R. Muench, Wolf Creek Nuclear Operating Corporation; dated September 25, 2003

Per Reference 1, Union Electric Company (AmerenUE) transmitted an application for amendment of the Facility Operating License (No. NPF-30) for the Callaway Plant. In that license amendment request (LAR) AmerenUE requested revision of Technical Specification (TS) 3.8.1, "AC Sources – Operating," and TS 3.8.4, "DC Sources – Operating," to allow certain surveillance tests for the onsite standby/emergency diesel generators and station batteries (respectively) to be performed during MODES in which performance of the tests is currently prohibited, and to incorporate changes based on Industry/Technical Specification Task Force (TSTF) Standard Technical Specification change TSTF-283, Revision 3.

A001

AmerenUE's application for amendment, along with similar applications from Wolf Creek Nuclear Operating Corporation, Arizona Public Service Company, and Pacific Gas and Electric Company, is currently under review by the NRC staff. From the NRC staff's review of these applications, the staff has identified the need for additional information to support its continued review of the applications. Per Reference 2, which was addressed to all four of the noted licensees, the NRC staff transmitted a request for additional information (RAI) regarding the proposed TS changes. Some of the questions / requests transmitted by the NRC RAI letter were identified as applicable to all four of the licensees, and some were identified as applicable only to certain licensees.

This letter provides, via Attachment 1, responses to all of the NRC staff's questions / requests identified as applicable to Callaway (which includes those identified as applicable to all four of the noted licensees). The attached responses support the TS changes as proposed in AmerenUE's June 6, 2003 application, and therefore do not constitute changes to what is proposed and do not require any changes to the evaluations contained in the application, including the Basis for No Significant Hazards Evaluation. One commitment was established in support of the RAI responses. This commitment is identified in Attachment 2.

The attached responses have been discussed with the NRC staff, including during a telephone conference that was conducted November 19, 2003 with all of above-noted licensees participating. One concern, in particular, was expressed by the NRC during that discussion, regarding the proposed changes to Surveillance Requirements (SRs) 3.8.4.7 and 3.8.4.8. These SRs specify testing requirements for the station batteries, and the proposed changes would provide the flexibility for performing portions of these surveillances to re-establish operability following corrective maintenance. Although the changes proposed for these SRs are consistent with TSTF-283 (Rev. 3) as approved by the NRC, the NRC has expressed concern that allowing portions of these surveillances to be performed at power could result in a partial discharge of the affected battery. To allow these concerns to be further addressed, AmerenUE has agreed with the NRC Project Manager that the proposed changes to SRs 3.8.4.7 and 3.8.4.8 will be processed separately (from the changes proposed to TS 3.8.1) based on the additional time that will likely be needed to resolve the identified concerns both generically and for AmerenUE.

Please contact us for any additional questions you may have regarding the attached responses or AmerenUE's amendment application.

Very truly yours,

Keith D. Young

Keith D. Young
Manager, Regulatory Affairs

TBE/mlo

Attachments: 1. Callaway Responses to Requests for Additional Information Regarding Proposed Changes to Technical Specification (TS) 3.8.1, "AC Sources – Operating," and TS 3.8.4, "DC Sources – Operating"

2. List of Commitments

cc: U. S. Nuclear Regulatory Commission (Original and 1 copy)
Attn: Document Control Desk
Mail Stop P1-137
Washington, DC 20555-0001

Bruce S. Mallet
Regional Administrator
U.S. Nuclear Regulatory Commission
Region IV
611 Ryan Plaza Drive, Suite 400
Arlington, TX 76011-4005

Senior Resident Inspector
Callaway Resident Office
U.S. Nuclear Regulatory Commission
8201 NRC Road
Steedman, MO 65077

Mr. Jack N. Donohew (2 copies)
Licensing Project Manager, Callaway Plant
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop 7E1
Washington, DC 20555-2738

Manager, Electric Department
Missouri Public Service Commission
PO Box 360
Jefferson City, MO 65102

STATE OF MISSOURI)
) SS
COUNTY OF CALLAWAY)

Keith D. Young, of lawful age, being first duly sworn upon oath says that he is Manager, Regulatory Affairs, for Union Electric Company; that he has read the foregoing document and knows the content thereof; that he has executed the same for and on behalf of said company with full power and authority to do so; and that the facts therein stated are true and correct to the best of his knowledge, information and belief.

By Keith D. Young

Keith D. Young
Manager, Regulatory Affairs

SUBSCRIBED and sworn to before me this 19th day of December, 2003.

TERRA E. COOK
Notary Public - Notary Seal
STATE OF MISSOURI
Callaway County
My Commission Expires May 13, 2006

Terra E. Cook

Callaway Responses to Requests for Additional Information Regarding Proposed Changes to Technical Specification (TS) 3.8.1, "AC Sources – Operating," and TS 3.8.4, "DC Sources – Operating"

The following responses are for those questions or requests for additional information (RAIs) identified as applicable to Callaway per the NRC's RAI letter dated September 25, 2003 (and electronically received on October 1, 2003). The RAIs/Questions identified as 1.a, 1.b and 1.c for "Callaway and Wolf Creek Only" in the enclosure of NRC's RAI letter were renumbered as 2.a, 2.b and 2.c below (to identify them separately from those that were identified as 1.a through 1.g for "Callaway, Diablo Canyon Units 1/2, Palo Verde Units 1/2/3, and Wolf Creek" in the NRC's enclosure). Note: With regard to references to the standby/emergency diesel generators, "DG" and "EDG" are used interchangeably in the questions and responses below.

* * * * * * * * * *

1.a *Surveillance Requirement (SR) 3.8.4.7 and SR 3.8.4.8 contain a Note that has been modified to add, "However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced." Provide the intent of this note in detail (i.e., what exactly will be done at power, the duration of these surveillances and its impact on the limiting condition of operation, details regarding assessment, etc.).*

Response:

In practice, the provision specified per the modified note will not likely be utilized since it takes many hours to perform a battery service or performance discharge test (including recovery of the battery following the test), and the battery is isolated and inoperable throughout such a test. "Partial" performance of such a test is also unlikely given the intrusive nature of the test and the fact that "partial" performance would not be useful except under very unusual circumstances. Further, the time required to complete even a partial performance could present a challenge relative to the two-hour Completion Time specified for restoration of an inoperable battery per Required Action A.1 of Technical Specification (TS) 3.8.4.

The proposed Note was included in SR 3.8.4.7 and SR 3.8.4.8 to provide for the possibility of a partial performance, however remote. Inclusion of the Note is in accordance with TSTF-283 (Revision 3) as approved by the NRC.

Note: The changes proposed for SRs 3.8.4.7 and 3.8.4.8 were discussed with the NRC staff during a telecon that was conducted November 19, 2003 with all of the above-noted licensees participating. Per that discussion, the NRC expressed concern that allowing portions of these SRs to be performed at power could result in a partial discharge of the affected battery. It was subsequently agreed that the proposed changes to SR 3.8.4.7 and SR 3.8.4.8 would be processed separately (from the changes proposed for the SRs under TS 3.8.1) to allow time to resolve the noted concerns for these SRs.

1.b *Do the work control programs, risk management programs, and/or procedures cover a comprehensive walk-down just prior to entering the period of reduced equipment availability during EDG testing? Provide details about the walk-down or justify why such a walk-down is not required.*

Response:

The work and risk management processes at Callaway would not necessarily require a walk-down to be performed prior to on-line EDG testing. The plant configuration (equipment status, etc.) would be known and tracked as is required, prior to performance of this or any other on-line testing. On a routine basis, plant walk-downs are performed by plant operators at least once per shift.

For SRs 3.8.1.10 and 3.8.1.14, it is not expected that the EDG under test would be made inoperable by such testing, so performance of either of these SRs on-line would not by itself constitute a "period of reduced equipment availability during EDG testing." For the remaining SRs affected by the proposed changes, performance of the SR either requires declaring the EDG inoperable in order to perform the SR (i.e., SR 3.8.1.13), or the SR will only be allowed to be performed in order to reestablish Operability following corrective maintenance, corrective modification, or any other unanticipated operability concern, as stipulated in the proposed TS (and TS Bases) changes. In the latter case, the EDG would already be inoperable, and the effect of that inoperability would thus have been evaluated with respect to plant risk, including any compensatory actions required, pursuant to the plant's procedure for evaluating and managing plant risk in accordance with 10 CFR 50.65(a)(4), i.e., Callaway procedure EDP-ZZ-01129, "Callaway Plant Risk Assessment." Moreover, in this case, the SR(s) that would apply would be one for which the modified Mode-restriction Note applies. The modified Note only allows the SR (or portions of the SR) to be performed "provided an assessment determines the safety of the plant is maintained or enhanced."

For the planned removal of an EDG from service - to perform SR 3.8.1.13, for example - the effect of the inoperability would still be evaluated with respect to plant risk in accordance with the above-noted Callaway procedure (EDP-ZZ-01129) which is also used in the scheduling and planning of system/component maintenance, testing and outages to assess the risk impact of such activities. The risk assessment would include consideration of any other concurrent equipment inoperability.

1.c *Indicate where the loss-of-offsite power signal comes from when the EDG is powering, or paralleled to, the safety bus.*

Response:

The loss-of-power relays sense voltage from the 4.16-kV safety buses, NB01 and NB02. This is the case whether an EDG is or is not powering its associated bus and whether the EDG is paralleled or not paralleled to the off-site power source.

1.d *Discuss administrative controls to preclude performing these surveillances during other maintenance and test conditions that could have adverse effects on the offsite power system, or plans for restricting additional maintenance or testing of required safety systems that depend on the remaining EDG as a source. Additionally, discuss if the remaining EDG were to become inoperable while the other EDG is being tested, would the test be aborted.*

Response:

The administrative controls and/or compensatory actions that may be applied depend, in part, on whether the EDG to be tested is rendered inoperable by the testing. For example, and as noted above, the EDG is not expected to be rendered inoperable during the performance of SRs 3.8.1.10 and 3.8.1.14, and therefore such testing alone would not be expected to have a risk-significant impact on the facility. The concurrent inoperability of any other equipment would be a consideration in the scheduling of such testing.

For testing that requires the EDG to be declared inoperable, additional actions may be taken. As noted previously, the planned inoperability of an EDG would require the application of Callaway's EDP-ZZ-01129 procedure. Per that procedure, the following guidance is specified for planned risk-significant activities associated with an EDG [and/or its associated essential service water (ESW) system loop (which provides cooling to the EDG)]:

For an EDG/ESW Outage:

- Minimize the chance for concurrent loss of offsite power (i.e., no inclement weather and/or no work in the switchyard that can cause a loss of offsite power).
- No work on the security diesel generator (which provides, or is capable of providing, back-up power to a limited number of systems or components).
- Follow established work sequences.
- No unscheduled safety work without a risk assessment.
- Shift and plant briefs should address a Safety Monitor status of "yellow."

In addition, for emergent work the following guideline is included in EDP-ZZ-01129:

> If the plant is in a risk-informed allowed outage time (AOT) and an additional risk-significant SSC becomes inoperable/non-functional, a risk assessment SHALL be performed and appropriate actions taken to reduce plant risk.

For the case when the other EDG becomes inoperable while an EDG test is underway, the decision to abort the test would be based on existing plant conditions, the purpose of performing the test, whether the test is one that affects EDG operability, what plant risk level is entered by the other EDG becoming inoperable, and the cause of the other EDG's inoperability (if it is known). For the EDG under test, it might be most prudent to complete the test if, for example, the test were being done to re-establish operability following corrective maintenance. On the other hand, if the EDG test had been initiated merely for routine on-line performance, the decision might be made to abort the test, particularly if the decision is made to "protect" the train associated with the EDG under test.

For testing that renders the EDG inoperable, the decision to abort the test in the event of the other EDG becoming inoperable would also be influenced by the resultant entry into the more severe TS Action statement for having both EDGs inoperable, which requires restoring one EDG to operable status within 2 hours. The decision on which EDG to restore first would depend on the current condition of each EDG, including whether the nature and cause of the failure of the other EDG is immediately known.

1.e *Discuss whether procedures are in place to alert operators when to perform either portions of or full SRs/Testing. Will the operators receive training on the procedures related to the proposed Technical Specification changes prior to implementation?*

Response:

The decision to perform one (or more) of the subject SRs, either in full or partially, would be based on the specific corrective maintenance or modification being performed. The required testing would be identified as part of the work plan for performing the on-line, corrective maintenance or modification, and would be included in the system/component (EDG) outage window. The process established in plant procedures on work controls and by the surveillance procedures themselves ensures that plant conditions are taken into account, that briefings are conducted, and that the shift manager is aware of test activities prior to performance.

With regard to training for operators, a process exists at Callaway whereby all license amendments, particularly Technical Specification changes, are reviewed and screened for operator training. The changes proposed per the subject application have been reviewed for such impact, and it has been identified that training will be provided to operators for the subject TS changes.

1.f *Discuss the compensatory measures that will be implemented during performance of SRs 3.8.1.10, 3.8.1.13, and 3.8.1.14.*

Response:

As noted previously, the performance of SR 3.8.1.10 or SR 3.8.1.14 will not likely require declaring the affected DG inoperable. Compensatory measures that may be taken include those identified in the amendment application, i.e., allowing only one DG to be tested at a time (so that the other DG remains operable during testing) and ensuring that SRs of this type are not scheduled during periods in which a higher potential for grid or bus disturbances exists, such as during severe weather. In addition, guidance will be included in the affected surveillance procedures for ensuring that consideration is given to restricting switchyard access and prohibiting elective maintenance within the switchyard that could challenge offsite power availability or create the potential for electrical disturbances. (This commitment is identified in Attachment 2)

For the performance of SR 3.8.1.13 during plant operation, the EDG will likely be made temporarily inoperable. If a determination were made to perform this test (or a portion of the test that renders the EDG inoperable) during plant operation, additional provisions per EDP-ZZ-01129 may apply, as described in the response to Question 1.d.

1.g *For SR 3.8.1.13, discuss (1) how the SR is performed and (2) how the safety injection (SI) signal is generated without disturbing power operation.*

Response:

Complete performance of this SR is done by two overlapping procedures. One procedure tests the generation of the SI signal to start the EDG, operates all SI-actuated equipment, and checks actuation of the generator protection bypass circuit by verifying the presence of the "Protection Bypass" light. The SI signal is produced for the test by actuating the SI slave relay test switch. It is anticipated that this test portion will continue to be performed in refueling outages during the "Loss of Offsite Power (LOOP) with SI" test (pursuant to SR 3.8.1.19).

The second procedure verifies proper operation of the generator protection bypass circuit. This is done by placing the EDG breaker in the test position using mechanical and electrical test jumpers, and pressing and holding the "generator protection bypass circuit test switch" while a "bypassed" protection relay is actuated. The test verifies the presence of the "Protection Bypass" light. Proper operation is checked by ensuring that the breaker lockout relay is not actuated and that all proper alarms are received. This is repeated for each bypassed device. This test is proposed to be performed outside of the refuel outages, i.e., during plant operation.

2.a *For SR 3.8.1.10, in Section 4.1.1 of the application, it is stated that "experience with this test has shown that the voltage 'perturbation' seen on the bus during and just after the load rejection is not significant, i.e. within 5 percent step change. Data recorded from past performances of this test show that bus voltage during the "transient" remains well above the minimum required voltage for bus loads and typically recovers within one second." Discuss the impact of this voltage transient on degraded voltage relays. Also, during power operation the voltages at the safety buses are relatively lower than during shutdown, what will be the voltage transient due to a full load rejection test at the lower voltages and its impact on degraded voltage relays?*

Response:

For the electrical transient that may occur during this test there is significant margin relative to the degraded voltage relay settings. The highest voltage level at which the degraded voltage relays may actuate (and not reset) is 91.5% of nominal (assuming maximum upward drift). In addition, the relays have a time delay of 119 +/- 11 seconds before an actuation can occur. This voltage level and time duration are not significantly approached during the load rejection test.

The voltage on the safety-related buses during plant operation is not significantly different than what it is during shutdown conditions, due to operation of the automatic load tap changing transformers (LTCs) at Callaway. During refueling outages, with the LTCs in manual, the voltage seen on the safety-related buses is a function of grid voltage. Therefore, voltage during refueling outages may or may not be lower than what it is during power operations. With a lower voltage, the transient will be larger due to dropping from a high voltage with the EDG supplying the bus to a lower bus voltage with the grid supplying the bus. Regardless, an inadvertent LOOP by operation of the degraded voltage relay(s) will not occur due to the 119-second time delay. Further, load flow analyses have been performed which confirm that steady-state voltages remain above the degraded voltage relay reset point so that transients (which are recovered from in seconds) will not cause a LOOP.

2.b *For SR 3.8.1.10, in Section 4.1.4 of the application, it is stated that "In the event of a LOOP occurring while a DG [diesel generator] is running and paralleled to offsite power for testing . . . At some point, however, because loading would exceed the DG's capability, the DG would be unable to match load and either the bus undervoltage relays would trip (after timing out) or the DG overcurrent or underfrequency relays would trip." Discuss the time associated with manually resetting the involved relays and components.*

Response:

There are five possible protective relays that could be actuated by grid events while a DG is paralleled to offsite power. These are underfrequency, degraded voltage, loss of voltage, time overcurrent, and voltage-restrained overcurrent. Only one of the five, voltage-restrained overcurrent, requires manual action to reset. Bus undervoltage protection (for degraded or loss of voltage) only serves to trip the incoming feeder breaker supplying offsite power to the bus. In the event of bus undervoltage protection actuation, the DG feeder breaker remains closed and continues to feed the bus. No manual action is required. Two other protective relay functions, underfrequency and time overcurrent, are primary protection and only serve to open the DG output breaker. No lockout of the breaker or DG occurs. The DG remains running and able to support loss of power events, if needed. No manual action is required. For secondary protection, there is the voltage-restrained overcurrent relay. However, due to protective relay coordination, this relay would not be called upon to actuate unless a primary relay failed to actuate properly. Thus, it is highly unlikely that this relay would be actuated during surveillances in which the emergency diesel generator is connected to the grid. In the unlikely event that the voltage-restrained overcurrent relay is actuated, a single lockout will shut down the DG and trip its associated output breaker. If the bus offsite feeder breaker opens due to the grid event, a single manual action of resetting the lockout relay will cause an immediate, automatic, restart of the DG in the emergency mode and allow the DG output breaker to automatically re-close.

2.c *Questions "a" and "b" above are also applicable to SR 3.8.1.14.*

Response:

The above responses also apply to SR 3.8.1.14.

LIST OF COMMITMENTS

The following table identifies actions to which Callaway Plant has committed in this document. Any other statements in the document are provided for information purposes and are not considered to be commitments. Questions regarding these commitments may be made to Dave Shafer, Superintendent – Licensing, at (314) 554-3104.

COMMITMENT	Due Date/Event
For the performance of surveillance testing pursuant to Technical Specification Surveillance Requirement (SR) 3.8.1.10 or SR 3.8.1.14 during plant operation, guidance will be included in the affected surveillance procedures for ensuring that consideration is given to restricting switchyard access and prohibiting elective maintenance within the switchyard that could challenge offsite power availability or create the potential for electrical disturbances.	Will become effective when the affected surveillance procedures are revised to allow such testing to be done during plant operation (after receipt of the license amendment).