UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001
April 20, 2000

Ms. Kay Drey
515 West Point Avenue
University City, MO 63130

Dear Ms. Drey:

By letter dated March 10, 2000, you sent me, as project manager at the Nuclear Regulatory Commission (NRC) for the Callaway Plant, Unit 1, a letter seeking information about (1) the reactor scram event that occurred at Callaway on Sunday, February 13, 2000, and (2) the electrosleeve amendment that the NRC issued as Amendment No. 132 on May 21, 1999.

Because you also provided the letter to the licensee for Callaway and the information you requested is beyond what information we have immediately available on Callaway, we have requested the licensee to address certain questions in your letter. The remaining questions in your letter will only be addressed by the NRC. Enclosed is a copy of the letter that was sent to the licensee (Enclosure 1). The letter included a table where we listed your questions and identified those questions that we requested the licensee to address.

The licensee's response, requested within 60 days of the receipt of our letter to them, will be in a letter to the NRC. After we have received and reviewed their responses and addressed the other questions, we will respond in writing to you on all the questions. I expect at this time that we should be responding to you in about 3 months (i.e., in July 2000); however, I can answer Questions A.6 and B.9 in this letter.

In your letter, you referred to the March 13, 2000, meeting the staff conducted with the licensee on the August 11, 1999, manual scram event at Callaway and asked if we expected to conduct a special inspection, similar to that conducted for the August 11, 1999, event, for the February 13, 2000, automatic reactor scram event at Callaway (Question A.6). You also requested that we provide you with our justification for allowing Callaway to be the first plant in the country licensed to perform the Framatone electrosleeving process to repair their steam generator tubes (Question B.9).

For Question A.6, upon review of the event, we decided that the February 13, 2000, event did not warrant a special inspection, such as was conducted for the August 11, 1999, manual scram event. The licensee's description of the second event is documented in its licensee event report (LER) 2000-002-00, "Automatic Reactor Trip Initiated by Reactor Coolant Pump Trip Caused by Motor Current Imbalance Due to Transmission System Disturbance," dated March 13, 2000 (Enclosure 2). The licensee stated in the LER that all safety-related and non-safety-related equipment functioned as designed, and there was no release of radioactivity. Thus, although both events were electrical grid-plant interactions, the August 11, 1999, event was an <u>unexpected</u> impact on the grid from a plant scram, and the February 13, 2000, event was an <u>expected</u> plant response to a grid perturbation. We, therefore, concluded that the February 13, 2000, event did not warrant a special inspection; however, a routine inspection was conducted of the event by the Callaway resident inspectors and documented in Inspection Report 50-483/00-01 dated March 7, 2000 (Enclosure 3). The meeting summary that the staff issued for the meeting on March 13, 2000, was issued on March 14, 2000 (Enclosure 4). The focus of the meeting was the transmission system perspective and corrective actions for the August 11, 1999, event because the impact on the grid had been unexpected. These were addressed by the licensee and none of the slides in the licensee's handout addressed the February 13, 2000, event. Although the February 13, 2000, event was briefly discussed in the meeting, neither the staff or the licensee believed the event needed to be extensively addressed in this meeting because the plant response to the event that occurred outside the Callaway system was as expected from the plant design.

For Question B.9, the staff's justification for its decision to approve Amendment No. 132 dated May 21, 1999, is given in the safety evaluation dated May 21, 1999, attached to the letter approving the amendment (Enclosure 4).

If you have any questions, please contact me at 301-415-1307 or, through the internet, at jnd@nrc.gov.

Sincerely,

JDonohew /RA/

Jack Donohew, Senior Project Manager, Section 2
Project Directorate IV & Decommissioning
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-483

Enclosures:
1. Letter to Callaway
2. Licensee Event Report dated March 13, 2000
3. Inspection Report 50-483/00-01 dated March 7, 2000
4. Meeting Summary dated March 14, 2000
5. Safety Evaluation dated May 21, 1999.

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JLazevnick

* See previous concurrence ** Voice mail in phone call

OFFICE	PDIV-2/PM	PDIV-2/LA	EMCB/BC	RGNIV	PDIV-2/SC
NAME	JDonohew:am	EPeyton	WBateman*	WJohnson**	SDembek
DATE	4/20/2000	4/20/00	04/17/00	04/19/00	4/20/00

DOCUMENT NAME: G:\PDIV-2\Callaway\MA8411Response1-Drey03-20-00Letter.cw.wpd

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

April 12, 2000

Mr. Garry L. Randolph
Vice President and Chief Nuclear Officer
Union Electric Company
Post Office Box 620
Fulton, MO 65251

SUBJECT: REQUEST FOR INFORMATION ON MS. KAY DREY'S LETTER OF MARCH 10, 2000 - CALLAWAY PLANT, UNIT 1 (TAC NO. MA8411)

Dear Mr. Randolph:

As project manager for the Callaway Plant, Unit 1, I received a letter from Ms. Kay Drey of University City, Missouri. Ms. Drey is seeking information about the reactor scram event at Callaway that occurred on Sunday, February 13, 2000, and the electrosleeve amendment that was issued as Amendment No. 132 on May 21, 1999. The letter is enclosed.

Ms. Drey also sent the letter to your Board of Directors and staff. We have discussed the letter with your staff and believe that your staff should provide answers to the questions that are not addressed solely to the Nuclear Regulatory Commission (NRC). These answers would be submitted by letter to the NRC and we would respond to Ms. Drey. The enclosed table lists the questions we are requesting that your staff address. Please use your copy of the letter for the actual questions, because the table only list summaries of the questions in the letter.

Based on the discussion with your staff, we request that you provide answers to the questions identified for your response in the enclosed table within 60 days of the receipt of this letter.

Sincerely,

Jack N. Donohew

Jack Donohew, Senior Project Manager, Section 2
Project Directorate IV & Decommissioning
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-483

Enclosures: 1. Letter dated March 10, 2000 from Ms. Kay Drey
2. Table of Questions

cc w/encls: See next page

ENCLOSURE 1

cc:

Professional Nuclear
Consulting, Inc.
19041 Raines Drive
Derwood, MD 20855

John O'Neill, Esq.
Shaw, Pittman, Potts & Trowbridge
2300 N. Street, N.W.
Washington, D.C. 20037

Mr. J. Schnock
Supervising Engineer
Quality Assurance Regulatory Support
Union Electric Company
Post Office Box 620
Fulton, MO 65251

U.S. Nuclear Regulatory Commission
Resident Inspector Office
8201 NRC Road
Steedman, MO 65077-1302

Mr. J. V. Laux, Manager
Quality Assurance
Union Electric Company
Post Office Box 620
Fulton, MO 65251

Manager - Electric Department
Missouri Public Service Commission
301 W. High
Post Office Box 360
Jefferson City, MO 65102

Regional Administrator, Region IV
U.S. Nuclear Regulatory Commission
Harris Tower & Pavilion
611 Ryan Plaza Drive, Suite 400
Arlington, TX 76011-8064

Mr. Ronald A. Kucera, Deputy Director
Department of Natural Resources
P.O. Box 176
Jefferson City, MO 65102

Mr. Otto L. Maynard
President and Chief Executive Officer
Wolf Creek Nuclear Operating Corporation
Post Office Box 411
Burlington, KA 66839

Mr. Dan I. Bolef, President
Kay Drey, Representative
Board of Directors Coalition
for the Environment
6267 Delmar Boulevard
University City, MO 63130

Mr. Lee Fritz
Presiding Commissioner
Callaway County Court House
10 East Fifth Street
Fulton, MO 65151

Mr. Alan C. Passwater, Manager
Licensing and Fuels
Union Electric Company
Post Office Box 66149
St. Louis, MO 63166-6149

April 10, 2000

TABLE OF MARCH 10, 2000 LETTER FROM MS. KAY DREY QUESTIONS

Question No./ Letter Page No.	Subject	Summary of Question	Licensee/NRC Response
A.1/page 3	Electrical transmission	Did any of the components fail independently, or was it a common-mode failure?	Licensee response
A.1/page 3	Electrical transmission	Did the grid system fluctuations cause only one power supply breaker to fail, or were other electrical controls affected?	Licensee response
A.1/page 3	Electrical transmission	Has NRC confirmed whether or not the grid system fluctuations caused only one breaker to fail?	NRC will address
A.2/page 3	Electrical transmission	How frequently has NRC been informed of similar disruptions in power?	NRC will address
A.2/page 3	Electrical transmission	Have fluctuating voltages frequently affected the operability of safety systems?	Licensee response
A.3/page 3	Electrical transmission	To what extent are surge protectors required on safety related equipment?	Licensee response
A.4/page 3	Electrical transmission	Did any of the warning sirens become inoperable during the period of fluctuating voltages?	Licensee response
A.5/page 3	Electrical transmission	Related to grid problems being anticipated by NRC.	NRC will address
A.6/page 3	Electrical transmission	Will NRC conduct a special inspection of Callaway for February 13th event?	NRC will address

Question No./ Letter Page No.	Subject	Summary of Question	Licensee/NRC Response
A.6/page 3	Electrical transmission	Question on August 11, 1999 event and failure to verify operability of the offsite power sources.	Licensee response
A.6/page 3	Electrical transmission	Sequence of environmental, economic, and human error conditions involving offsite and onsite systems.	Licensee response
A.6/page 3	Electrical transmission	Voltage problems caused by near-peak summertime power wheeling.	Licensee response
B.1/page 4	Steam generators (SGs)	How much the licensee knew, when he knew it, and the amount of radioactivity in the secondary water when SG atmospheric dump valves (ADVs) opened.	Licensee response
B.1(a)/page 4	Steam generators	Concentration of radioactivity prior to 2/13 event.	Licensee response
B.1(b)/page 4	Steam generators	How much in advance of the 2/13 event had the secondary coolant sample been analyzed and reported to NRC?	Licensee response
B.2/page 4	Steam generators	Pounds of steam released from opened SG ADVs. How many per SG were open? Was this noisy?	Licensee response
B.3/page 4	Steam generators	Was radioactivity released from paths other than the ADVs?	Licensee response
B.4/page 5	Steam generators	Did the fluctuating voltages affect any electronic radiation detectors?	Licensee response

Question No./ Letter Page No.	Subject	Summary of Question	Licensee/NRC Response
B.5/page 5	Steam generators	Has any condenser cooling water leaked into the SGs over the years and caused any damage?	Licensee response
B.6/page 5	Steam generators	Three questions on pressurizer power operated relief valve (PORV) that opened.	Licensee response
B.7/page 5	Steam generators	Current permissible primary-to-secondary leak rate limit.	Licensee response
B.7/page 5	Steam generators	The Technical Specification leak rate that NRC is confident will not result in a sudden tube rupture.	NRC will address
B.8/page 5	Steam generators	The report that describes the predominant tube wall deformation and defects detected in the SGs that lead to the application for the electrosleeve amendment.	Licensee response
B.8/page 5	Steam generators	The reports the NRC has on such SG defects.	NRC will address
B.9/page 5	Steam generators	Justification for NRC decision to approve electrosleeve amendment.	NRC will address
B.10/page 5	Steam generators	Test results provided to NRC to justify electrosleeve process.	Licensee response
B.10/page 5	Steam generators	Test results used by NRC to justify its decision to approve electrosleeve amendment.	NRC will address

Question No./ Letter Page No.	Subject	Summary of Question	Licensee/NRC Response
B.11/page 6	Steam generators	Did Argonne National Laboratory resolve staff's concerns about electrosleeved tube failures under severe accident conditions?	NRC will address
B.12/page 6	Steam generators	Any examination of integrity of electrosleeved tubes.	Licensee response
B.13/page 6	Steam generators	Two-operating cycle limit in electrosleeve amendment and will electrosleeved tubes be removed then. What is the experience on removing such tubes?	Licensee response
B.14/page 6	Steam generators	Percentage of SG tubes that are not operable, that are electrosleeved, and that are sleeved.	Licensee response
B.15/page 6	Steam generators	Percentage of SG tubes that are plugged. Any plugs removed or dislodged?	Licensee response
B.16/page 6	Steam generators	Has sleeving and plugging SG tubes reduced SG heat removal capacity and, if not, why not?	Licensee response
B.17/page 6	Steam generators	Inspection of SG tube plates. There are 4 parts to question.	Licensee response
B.18/page 7	Steam generators	Occupational exposure of workers doing electrosleeving (including possible removal) versus SG replacement.	Licensee response
B.19/page 7	Steam generators.	Estimate and schedule for SG replacement.	Licensee response

Question No./ Letter Page No.	Subject	Summary of Question	Licensee/NRC Response
B.20/page 7	Steam generators.	NRC criteria on permissible SG tube cracks.	NRC will address
B.21/page 7	Waterhammer	Did the February 13, 2000 event caused by voltage fluctuations result in mechanical damage to the cooling water systems?	Licensee response
B.22/page 7	Callaway machine shop	What are the quality assurance/quality control procedures imposed on the machine shop?	Licensee response
B.22/page 7	Callaway machine shop	Extent of NRC oversight of machine shop.	NRC will address

Union Electric
Callaway Plant

PO Box 620
Fulton, MO 65251

March 13, 2000

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

ULNRC-4200

Gentlemen:

DOCKET NUMBER 50-483
CALLAWAY PLANT UNIT 1
UNION ELECTRIC CO.
FACILITY OPERATING LICENSE NPF-30
LICENSEE EVENT REPORT 2000-002-00
Automatic Reactor Trip Initiated by Reactor Coolant Pump Trip Caused by Motor Current Imbalance Due to Transmission System Disturbance

The enclosed licensee event report is submitted in accordance with 10CFR50.73(a)(2)(iv) to report an event that resulted in an automatic actuation of an Engineered Safety Feature and automatic actuation of the reactor protection system.

Warren A. Witt for
R. D. Affolter
Manager, Callaway Plant

RDA/ddm

Enclosure

ENCLOSURE 2

cc: Mr. Ellis W. Merschoff
Regional Administrator
U.S. Nuclear Regulatory Commission
Region IV
611 Ryan Plaza Drive, Suite 400
Arlington, TX 76011-8064

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 OWFN-4D3
Washington, DC 20555-2738

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

Records Center
Institute of Nuclear Power Operations
700 Galleria Parkway
Atlanta, GA 30339

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Callaway Plant Unit 1	0 5 0 0 0 4 8 3	1 OF 0 4

TITLE (4) **Automatic Reactor Trip Initiated by Reactor Coolant Pump Trip Caused By Motor Current Imbalance Due to External Transmission System Disturbance**

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)		
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	Rev No.	MONTH	DAY	YEAR
0 2	1 3	2 0 0 0	2 0 0 0	- 0 0 2 -	0 0	0 2	1 3	2 0 0 0

OTHER FACILITIES INVOLVED (8)

FACILITY NAMES	DOCKET NUMBER(S)
	0 5 0 0 0
	0 5 0 0 0

OPERATING MODE (9)	1
POWER LEVEL (10)	1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR : (*Check one or more of the following*) (11)

20.2201(b)	20.2203(a)(2)(v)	50.73(a)(2)(i)	50.73(a)(2)(viii)
20.2203(a)(1)	20.2203(a)(3)(i)	50.73(a)(2)(ii)	50.73(a)(2)(x)
20.2203(a)(2)(i)	20.2203(a)(3)(ii)	50.73(a)(2)(iii)	73.71
20.2203(a)(2)(ii)	20.2203(a)(4)	X 50.73(a)(2)(iv)	OTHER (*Specify in Abstract below or in Text, NRC Form 366A*)
20.2203(a)(2)(iii)	50.36(c)(1)	50.73(a)(2)(v)	
20.2203(a)(2)(iv)	50.36(c)(2)	50.73(a)(2)(vii)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (AREA CODE)
J. D. Schnack, Supervising Engineer, QA Corrective Action	5 7 3 6 7 6 - 4 3 1 9

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO EPIX

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e. approximately fifteen single-space typewritten lines) (16)

At 07:34 on February 13, 2000, automatic actuation of the reactor protection system (RPS) was initiated due to a low reactor coolant flow condition. This condition resulted when a reactor coolant pump (RCP) motor's protective relay sensed an electrical disturbance occurring on the transmission system, subsequently tripping the pump. The cause of the disturbance was attributed to a transmission line breaker failing to operate due to a defective electrical connection within the neighboring electric cooperative's protective relaying scheme. This resulted in an eight-minute system disturbance. At the time of the event, the plant was operating in Mode 1 at 100 percent power. Upon receiving the RPS actuation, all safety-related and nonsafety-related systems functioned per design.

Ameren took corrective action to review the adequacy of their transmission system and RCP protective relaying setpoints. Completion of this review determined that Ameren's transmission system and RCP relay setpoints were adequate in the level of protection they provided and that the relays functioned per designed during the event. Ameren is also monitoring corrective actions of the electric cooperative, which has committed to installing backup relaying at the affected substation.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REV NO.	PAGE (3)
Callaway Plant Unit 1	0 5 0 0 0 4 8 3	2 0 0 0	- 0 0 2 -	0 0	0 2 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's)(17)

DESCRIPTION OF EVENT:

At 07:34:18 on February 13, 2000, an automatic reactor trip was initiated due to a low reactor coolant flow condition following a trip of the 'B' Reactor Coolant Pump (RCP) motor. The RCP trip was initiated by a current imbalance sensed by the motor's protective relay. The current imbalance was a result of a transmission system disturbance. At the time of the event, the plant was operating in Mode 1 at 100 percent power.

The system disturbance was initiated by a transmission line fault within a neighboring electric cooperative's transmission system. Due to a defective electrical connection within the electric cooperative's protective relaying scheme, the transmission line breakers protecting the affected line did not receive a trip signal to clear the fault. Since the breaker failure relaying scheme utilized the same circuitry containing the defective electrical connection, breaker failure logic was not initiated to trip the next breakers upstream of the transmission line fault. In addition, there was no redundant line relaying or local backup relaying on the substation transformer. As a result, the fault was not properly cleared from the electric cooperative's transmission system. For approximately the next eight minutes, multiple subsequent faults were introduced onto the system as the transmission line incurred damage and fell to the ground over an approximate distance of six miles. Ultimately, the fault condition was cleared following the failure of the distribution system transformer supplying the faulted transmission line.

Approximately one minute into the event, the "B" RCP tripped due to a motor current imbalance, which resulted from the transmission system disturbance. The automatic reactor trip was initiated for a low reactor coolant flow condition due to the RCP trip. Shortly after the reactor trip, the three remaining RCPs and all main condenser circulating water pumps also tripped because of motor current imbalance.

Due to the tripping of all RCPs, the pressurizer spray system was unavailable. Additionally, all main condenser circulating water pumps tripping affected the ability to use the main condenser as a heat sink. This resulted in reliance on the atmospheric steam dumps causing reactor coolant system average temperature (RCS Tavg) to increase from 557 to 562 degrees F. The combination of establishing natural circulation due to the loss of all RCPs and increasing RCS Tavg, caused a pressurizer in-surge raising RCS pressure to the pressurizer power-operated relief valve (PORV) setpoint. Prior to re-establishing the pressurizer spray system, both PORVs momentarily lifted once, relieving RCS pressure to the pressurizer relief tank. RCPs were restored approximately 32 minutes after initiation of the event.

During this entire event, all safety-related and nonsafety-related systems and components functioned per design.

TEXT (If more space is required, use additional NRC Form 366A's)(17)

BASIS FOR REPORTABILITY:

The event is reportable per 10CFR50.72(b)(2)(ii) as an event resulting in automatic actuation of an Engineered Safety Feature (ESF), including the Reactor Protection System (RPS).

CONDITION AT TIME OF EVENT:

Mode 1: Power operations at 100% power.

ROOT CAUSE:

The cause of the transmission system disturbance, which created the RCP motor current imbalance, was attributed to a defective electrical connection within the neighboring electric cooperative's protective relaying scheme. This prevented proper breaker operation to clear their transmission system fault.

CORRECTIVE ACTIONS:

1) Ameren is monitoring actions that are under way by the electric cooperative for implementing improvements to the protective relaying scheme at the affected substation. The electric cooperative has committed to installing backup relaying on the substation transformer before it is re-energized.

2) Since breakers within the Ameren transmission system did not operate to clear the system disturbance prior to the RCPs tripping on motor current imbalance, the Ameren transmission system protective relaying setpoints were reviewed for adequacy. This review determined that the relaying functioned as designed during this event and that the relay setpoints were appropriate for providing the proper level of overlap in fault protection between the two company's protective relaying schemes. It was determined that the protective relay settings provided the optimal level of system protection and that they were consistent with North American Electric Reliability Council (NERC) and Mid-America Interconnected Network (MAIN) regional reliability council standards.

3) RCP motor current imbalance relaying setpoints were also reviewed for adequacy as a result of this event. This review determined that the relay setpoints were appropriate for providing the proper level of motor protection and that the relay functioned as designed during the event.

SAFETY SIGNIFICANCE:

A probabilistic risk assessment (PRA) was conducted to evaluate the reactor trip and resulting plant response to the voltage transient. The PRA took into account the plant conditions immediately following the event and was considered to be a conservative estimate of the conditional probability of core damage. The PRA determined that the event was not significant with respect to the health and safety of the public. In response to the automatic reactor trip, the plant's engineered safety features functioned per their design. There was no release of radioactive material to the environment resulting from the event.

PREVIOUS OCCURRENCES:

There have been no previous reactor trips due to a system disturbance that was caused by malfunctioning equipment of a neighboring electric utility's transmission system.

FOOTNOTES:

The system and component codes listed below are per IEEE Standard 805-1984 system codes:

- AB Reactor Coolant System
- FK Switchyard System
- JE Engineered Safety Features Actuation System
- KE Heat Rejection System

and IEEE Standard 803A-1983 component code:

- RLY Relay

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-8064

MAR - 7 2000

Garry L. Randolph, Vice President and
Chief Nuclear Officer
Union Electric Company
P.O. Box 620
Fulton, Missouri 65251

SUBJECT: NRC INSPECTION REPORT NO. 50-483/00-01

Dear Mr. Randolph:

This refers to the inspection conducted on January 9 through February 19, 2000, at the Callaway Plant facility. The enclosed report presents the results of this inspection.

Based on the results of this inspection, the NRC has determined that two Severity Level IV violations of NRC requirements occurred. These violations are being treated as noncited violations, consistent with Section VII.B.1.a of the Enforcement Policy. These noncited violations are described in the subject inspection report. If you contest the violations or severity level of these noncited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Callaway Plant.

In accordance with 10 CFR Part 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response, if requested, will be placed in the NRC Public Document Room.

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

WDJohnson

William D. Johnson, Chief
Project Branch B
Division of Reactor Projects

Docket No.: 50-483
License No.: NPF-30

ENCLOSURE 3

Enclosure:
NRC Inspection Report No.
50-483/00-01

cc w/enclosure:
Professional Nuclear Consulting, Inc.
19041 Raines Drive
Derwood, Maryland 20855

John O'Neill, Esq.
Shaw, Pittman, Potts & Trowbridge
2300 N. Street, N.W.
Washington, D.C. 20037

H. D. Bono, Supervising Engineer
Quality Assurance Regulatory Support
Union Electric Company
P.O. Box 620
Fulton, Missouri 65251

Manager - Electric Department
Missouri Public Service Commission
301 W. High
P.O. Box 360
Jefferson City, Missouri 65102

Ronald A. Kucera, Director
of Intergovernmental Cooperation
P.O. Box 176
Jefferson City, Missouri 65102

Otto L. Maynard, President and
Chief Executive Officer
Wolf Creek Nuclear Operating Corporation
P.O. Box 411
Burlington, Kansas 66839

Dan I. Bolef, President
Kay Drey, Representative
Board of Directors Coalition
for the Environment
6267 Delmar Boulevard
University City, Missouri 63130

ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket No.:	50-483
License No.:	NPF-30
Report No.:	50-483/00-01
Licensee:	Union Electric Company
Facility:	Callaway Plant
Location:	Junction Highway CC and Highway O Fulton, Missouri
Dates:	January 9 through February 19, 2000
Inspectors:	V. G. Gaddy, Senior Resident Inspector J. D. Hanna, Resident Inspector
Approved By:	W. D. Johnson, Chief, Project Branch B

ATTACHMENT: Supplemental Information

EXECUTIVE SUMMARY

Callaway Plant
NRC Inspection Report No. 50-483/00-01

This routine announced inspection included aspects of licensee operations, engineering, maintenance, and plant support activities. This report covers a 6-week period of resident inspection.

Operations

- The licensee's guidance for controlling access to the switchyard while at power was lacking. Operations personnel authorized and security personnel granted access to the switchyard. However, after security personnel granted access, additional personnel and equipment could enter the switchyard without further authorization from operations personnel. Licensee contingency planning procedures did recommend that switchyard entries be limited to operations personnel during critical evolutions such as midloop operations and reduced inventory conditions (Section O1.1).

- Control room operators demonstrated good command and control during the reactor startup following a reactor trip on February 13. Reactor engineering personnel and control room operators were attentive during the approach to criticality and subsequent reactor startup (Section O1.2).

- Breaker protection for a faulted 161 kV power line in southeast Missouri did not operate. This caused significant fluctuations on the licensee's switchyard buses. These fluctuations caused all reactor coolant pumps and all circulating water pumps to trip. The reactor subsequently tripped on low reactor coolant system flow. Without reactor coolant pumps, decay heat was removed by natural circulation. Operators quickly characterized the event and made restarting reactor coolant pumps a priority. The risk assessment for this event showed that the event had low to moderate risk significance (Section O2.2).

- Control room operators failed to identify a decreasing level in a component cooling water surge tank. Surge tank level decreased below the acceptance criteria. Operators documented that the surge tank level was below the acceptance criteria while taking control room logs. Operators did not document the suspected cause of the low surge tank level or take action to restore the level in the surge tank as required by procedure. Failing to take action to restore the surge tank level when it trended below the minimum acceptance criteria is a violation of 10 CFR Part 50 Appendix B, Criterion V. Operators took action to stop the decreasing level when the surge tank low level annunciator alarmed. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy (Section O4.1).

- The inspectors identified several deficiencies that contributed to a containment isolation valve being removed from service without proper time tracking or retests being specified. These deficiencies included the licensee's inattention to detail regarding the scheduling and isolation for the containment isolation valve, the lack of communication between the shift supervisor and the shift technical advisor, and not recognizing that removing the valve from service placed the plant in a limiting condition for operation (Section O4.2).

- Training provided to operations personnel on degraded switchyard voltage was well organized and gave guidance on how to detect an undervoltage condition and how to restore offsite power to an operable status (Section O5.1).

- In the event of a strike, the licensee did not plan to train replacement operators as crews prior to standing watch. By not training operators as crews, the licensee would miss an opportunity to develop crew team building and an opportunity to evaluate how replacement crews' members interacted with each other and how they performed under normal and emergency situations (Section O8.1).

Maintenance

- The inspectors noted an increased number of secondary plant steam leaks. These leaks had all been identified by the licensee and had been prioritized for repair. The inspectors also determined that the operability of surrounding equipment was not affected (Section M2).

Engineering

- The licensee was experiencing approximately 2 to 3 gallons per day leakage from a safety injection accumulator. Leakage from the accumulator was occurring through an accumulator test line. The licensee has been proactive in their attempts to stop the leakage from the accumulator and the reactor coolant system. The licensee does not have a program to monitor for nitrogen voids in the safety injection system and the residual heat removal system piping. The current guidance for venting the safety injection and residual heat removal systems did not require the licensee to take any action unless 30 seconds of gas was vented from a vent location. The licensee did not have a technical basis for the 30 second criteria. The licensee planned to install a manual isolation valve in the safety injection test line system to prevent leakage from the accumulator and to stop leakage past reactor coolant system check valves (Section E1.1).

- In 1997, the licensee identified that the reactor coolant system leakage detection system was outside its design basis because a 1 gpm leak could not be detected within 1 hour as required. Although outside design basis, the licensee failed to report this condition as required by 10 CFR Part 50.72. Failing to report this condition was a violation. This Severity Level IV violation is being treated as a noncited violation consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation was entered into the licensee's corrective action program as Suggestion-Occurrence-Solution Report 99-3541 (Section E8.2).

Plant Support

- During a containment building entry, health physics technicians demonstrated good ALARA techniques and compliance with the licensee's radiological procedures (Section R1.2).

Report Details

Summary of Plant Status

The plant began the report period at 100 percent power. On February 13, switchyard voltage fluctuations occurred. These voltage fluctuations caused reactor coolant Pump B to trip on a current phase imbalance. Following the reactor coolant pump trip, at approximately 7:34 a.m., the reactor tripped on low reactor coolant system flow. At 9:10 p.m. the reactor was restarted and at 5:18 a.m., on February 14, the main generator was synchronized to the electric grid. Full power was reached on February 16 and the plant remained at 100 percent for the remainder of the inspection period. Details about the reactor trip are discussed in Section O2.2 of this report.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety conscious. Plant status, operating problems, and work plans were appropriately addressed during daily turnover and plan-of-the-day meetings. Plant testing and maintenance requiring control room coordination were properly controlled. The inspectors observed several shift turnovers and noted no problems.

The inspectors observed nonlicensed operators performing their duties throughout the inspection period. On February 9, 2000, the inspectors accompanied the outside operator on his rounds. The operator was very knowledgeable and performed his duties in a satisfactory manner. During the tour, the inspectors noted that several bottles of compressed gas were stored in the switchyard. The inspectors asked why the bottles were in the switchyard. The inspectors learned that the bottles were used on February 4 to add gas to switchyard breakers and they were waiting to be removed. The bottles were subsequently removed from the switchyard.

The inspectors asked if there was any procedural guidance that governed switchyard access and equipment that could be taken into the switchyard. Access was authorized by operations personnel and granted by security personnel. However, after security personnel granted access, additional personnel and equipment could enter the switchyard without further authorization from operations personnel.

The licensee's contingency planning procedures recommended that switchyard entries be limited to operations personnel during critical evolutions such as midloop and reduced inventory.

O1.2 Observation of Reactor Startup

a. Inspection Scope (71707)

On February 13, operators commenced reactor startup and achieved criticality following a reactor trip due to a fault on the electrical grid in southeast Missouri. The inspectors observed the plant startup and related activities.

b. Observations and Findings

Prior to commencing the startup, operators conducted a briefing and limited personnel access to the control room to minimize distractions. The reactor startup was conducted in accordance with Procedure OTG-ZZ-00002, "Reactor Startup," Revision 26. Control room operators adhered to procedural requirements and performed the reactor startup cautiously and methodically. Operators utilized three-way communications during the evolution. A reactor engineer was stationed in the control room to perform independent verifications of subcritical multiplication and reactivity calculations as required by the procedure. Criticality was achieved within the range allowed by the estimated critical rod position calculation. The inspectors found that the licensee maintained proper control room decorum and performed the reactor startup with few problems. A detailed assessment of the reactor trip and associated operator response appears in Section O2.2 of this report.

c. Conclusions

Control room operators demonstrated good command and control during the reactor startup following a reactor trip on February 13. Reactor engineering personnel and control room operators were attentive during the approach to criticality and subsequent reactor startup.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature System Walkdowns (71707)

The inspectors walked down accessible portions of the following engineered safety features and vital systems:

- auxiliary feedwater system
- safety injection system
- containment spray system

Equipment operability, material condition, and housekeeping were acceptable.

02.2 Automatic Reactor Trip Due to Low Reactor Coolant System Flow

a. Inspection Scope (71707)

The inspectors followed up to determine the circumstances surrounding a reactor trip.

b. Observations and Findings

On February 13, 2000, at 7:33 a.m., voltage fluctuations occurred on the licensee's offsite power buses. Normal switchyard bus voltage was approximately 360 kV. The fluctuations varied voltage from 337 kV to 373 kV. At 7:34 a.m., reactor coolant Pump B tripped on a current phase imbalance. Immediately after the reactor coolant pump tripped, the reactor tripped on low reactor coolant system flow. The remaining three reactor coolant pumps and all three circulating water pumps tripped on a current phase imbalance. Without forced reactor coolant flow, decay heat was removed by natural circulation. The voltage fluctuations lasted for approximately 12 minutes.

At approximately 8 a.m., the licensee started reactor coolant Pumps A and D, restoring forced circulation. At 9:40 a.m., the remaining two reactor coolant pumps were started.

Following a reactor trip, pressure increases were normally controlled by the pressurizer spray valves. However, with all reactor coolant pumps tripped, the pressurizer spray driving force was unavailable. As a result, pressurizer pressure increased, causing a pressurizer power-operated relief valve to lift and then reseat. The power-operated relief valve's setpoint was 2335 psig. At the same time that the power-operated relief valve lifted, the safety valve open annunciator alarmed in the control room. Although the safety valve open annunciator alarmed, there were no other indications that a safety valve lifted. Safety valve tail pipe temperature remained normal and pressure remained constant. While troubleshooting the annunciator, the licensee determined that a reed switch that input to the annunciator was out of adjustment. The reed switch was repaired and the annunciator cleared.

When the circulating water pump tripped, condenser vacuum was lost, and the steam dump valves were unavailable to regulate pressure. Steam dumps normally operated at 1092 psig at no load. Temperature and pressure were controlled using steam generator atmospheric dump Valve D. The relief setpoint for this valve was 1125 psig. At approximately 9 a.m., the licensee restarted two circulating water pumps, reestablished condenser vacuum, and closed steam generator atmospheric dump Valve D.

All safety systems operated as designed and all control rods inserted. The offsite power sources remained operable.

The cause of the fluctuating switchyard voltage and subsequent reactor trip was a downed 161 kV power line in southeast Missouri. Breakers designed to isolate the downed line did not operate. This caused repeated high current until a 345 kV/161 kV transformer, that provided the interface with the licensee's electrical grid, failed. The affected power line, breakers, and transformers were owned and serviced by another (non-nuclear) utility. The licensee planned to meet with this utility to determine why their line protection devices failed. The licensee was also evaluating methods to reduce their susceptibility to similar events.

Operators' performance, following the reactor trip, was good. They properly characterized the event and established proper priorities to mitigate the event. Restarting reactor coolant pumps to reestablish forced circulation was a priority. Although operators had indication that a safety valve had lifted, operators quickly determined that this indication was incorrect. This incorrect indication had minimal effect on how operators responded to the event.

The licensee performed a risk assessment of the event. The analysis showed that this event was of low to moderate risk significance. Region IV senior reactor analysts reviewed the results of the licensee's risk assessment and concluded that the licensee had used a reasonable approach in assessing the overall risk of the event.

c. Conclusions

Breaker protection for a faulted 161 kV power line in southeast Missouri did not operate. This caused significant fluctuations on the licensee's switchyard buses. These fluctuations caused all reactor coolant pumps and all circulating water pumps to trip. The reactor subsequently tripped on low reactor coolant system flow. Without reactor coolant pumps, decay heat was removed by natural circulation. Operators quickly characterized the event and made restarting reactor coolant pumps a priority. The risk assessment for this event showed that the event had low to moderate risk significance.

O4 Operator Knowledge and Performance

O4.1 Decreasing Level in the Component Cooling Water Surge Tank

a. Inspection Findings

The inspectors followed up to determine why control room operators did not notice a decreasing level in a component cooling water surge tank.

b. Observations and Findings

At midnight on January 26, 2000, reactor operators' logs indicated that the component cooling water surge Tank A level was 72 percent. At 10:31 p.m. on January 27, the component cooling water surge Tank A low level annunciator alarmed. The low level alarm setpoint was 45 percent. Operators entered off-normal Procedure OTO-EG-00001, "Component Cooling Water System Malfunction." Operators started component cooling water Pump B as directed by procedure, transferred all safety loads to the opposite train, and began troubleshooting to isolate the leak from the component cooling water system.

During troubleshooting, the licensee narrowed the source of leakage from the surge tank to the radiation waste building. As directed by procedure, operators closed Valves EGHV69 and EGHV70 (radiation waste building supply and return valves). Closing these valves stopped the leakage. The leakage was estimated to be 0.6 gallons per minute. From midnight January 2, until the low level alarm, component cooling water level in Surge Tank A decreased approximately 27 percent.

Operations personnel reviewed the reactor operators' logs and noted that the level in component cooling water surge Tank A had steadily decreased over the previous 20 hours. On January 26, the midnight, 8 a.m., and 4 p.m. surge tank levels were 72 percent, 72 percent, and 68 percent, respectively. On January 27, the midnight, 8 a.m., and 4 p.m. surge tank readings were recorded as 62 percent, 55 percent, and 49 percent, respectively. The January 27, 4 p.m. reading was below the 50 percent acceptance criteria. After each set of readings was taken, they were reviewed by the control room supervisor. The control room supervisor did not investigate to determine the cause of the decrease in surge tank level.

The inspectors learned that, during the time that the surge tank level was decreasing, the licensee was performing work on component cooling water Pump B and on valves in the radiation waste building. The licensee indicated that operators may have assumed that the steady decrease in surge tank level was due to ongoing work.

Although a decrease in surge tank level had developed, operators did not investigate to determine the reason for the negative trend. The 4 p.m. surge tank reading was below the acceptance criteria and operators did not take action to correct the condition as required by Procedure ODP-ZZ-00016, "Reactor Operator Watchstation Practices and Logs." Steps 3.3.2 and 3.3.3 of this procedure required reactor operators to report conditions which were out of specification to the shift supervisor or control room supervisor and document the suspected cause and action taken to correct the condition. Step 3.2.3 required the shift supervisor or control room supervisor to provide guidance to reactor operators to correct the out of specification condition. Failing to recommend and take action to correct the out of specification component cooling water surge tank level was a violation of 10 CFR Part 50 Appendix B, Criterion V. This Severity Level IV violation is being treated as noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation was entered into the licensee's corrective action program as Suggestion-Occurrence-Solution Report 00-0185 (50-483/00001-01).

The licensee identified other operator performance issues. To address this adverse trend, the licensee initiated Suggestion-Occurrence-Solution Report 00-00375.

c. <u>Conclusions</u>

Control room operators failed to identify a decreasing level in a component cooling water surge tank. Surge tank level decreased below the acceptance criteria. Operators documented that the surge tank level was below the acceptance criteria while taking control room logs. Operators did not document the suspected cause of the low surge tank level or take action to restore the level in the surge tank as required by procedure. Failing to take action to restore the surge tank level when it trended below the minimum acceptance criteria is a violation of 10 CFR Part 50, Appendix B, Criterion V. Operators stopped the decreasing level when the surge tank low level annunciator alarmed. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy.

O4.2 Errors Associated with Work on Containment Isolation Valve

a. Inspection Scope (71707)

On January 12, 2000, control room operators recognized that a retest had not been performed for containment isolation Valve EJHCV8825. Maintenance work on this valve had been completed the previous day.

b. Observations and Findings

On January 6, 2000, the licensee placed workman's protection assurance tags during a containment entry. This was done in preparation for spring adjustment work to be performed on containment isolation Valve EJHCV8825 the following week. (The placement of this workman's protection assurance isolation did not render the valve inoperable. Therefore, entry into Technical Specification Action Statement 3.6.3 for containment isolation valves was not required.) The shift supervisor then placed a hold off tag on the isolation valve in order to prevent the work from being performed without the control room staff being informed. On January 7, the work document was reviewed and approved by the licensee's planning department.

On January 10, the shift technical advisor performed a review of workman's protection assurance isolation for scheduled work. The containment isolation valve work did not appear on this report because it had not been scheduled. Because these work documents and associated isolation did not appear on this report, an equipment out-of-service list was not generated at the time. (An equipment out-of-service list is the licensee's mechanism to track Technical Specification allowed outage times and other time restricted items in order to verify completion. Typically, this mechanism is controlled by the shift technical advisor.) Later that morning, the work document was added to the schedule for the following day. No retest was scheduled for the containment isolation valve. The retest was added after the daily planning meeting; therefore, the retest document did not appear on the schedule until the following day.

On January 11, at 7:07 a.m., the hold-off tag was removed and the work was performed. The licensee considered the valve to be inoperable at the time the hold-off tag was removed. The shift technical advisor was not informed that the hold-off tag had been removed. Consequently, the licensee did not generate an equipment out-of-service list for the valve.

On January 12, the shift supervisor noted that the retest document for Valve EJHCV8825 had not been completed and informed the control room immediately. Operators then realized that Valve EJHCV8825 was a containment isolation valve. The licensee entered Technical Specification Action Statement 3.6.3 due to the inoperability of the valve. Further investigation revealed that the Technical Specification action statement requirements were met, during the period in question, by having the upstream valve, Valve EJHV8840, closed with its power removed. The equipment out-of-service list was retroactively entered by the licensee and the retests were satisfactorily performed.

The inspectors did not identify any noncompliance with the licensee's Technical Specifications or procedures. The inspectors did identify several deficiencies that contributed to this event. These included:

- the licensee's inattention to detail regarding the retest scheduling and the associated workman's protection isolation for the valve,
- lack of communication between the shift supervisor and the shift technical advisor with respect to the lifting of the hold-off tag on the work, and
- not recognizing that removing the valve from service placed the plant in a limiting condition for operations.

The inspectors reviewed the licensee's corrective actions for this event and found them to be adequate. The licensee entered this occurrence into its corrective action program as Suggestion-Occurrence-Solution Report 00-0061.

c. Conclusions

The inspectors identified several deficiencies that contributed to a containment isolation valve being removed from service without proper time tracking or retests being specified. These deficiencies included the licensee's inattention to detail regarding the scheduling and isolation for the containment isolation valve, the lack of communication between the shift supervisor and the shift technical advisor, and not recognizing that removing the valve from service placed the plant in a limiting condition for operations.

O5 Operator Training and Qualification

O5.1 Degraded Switchyard Voltage Training (71707)

On January 28, 2000, the inspectors attended training given to operations personnel regarding degraded switchyard voltage. This issue was the subject of an NRC special inspection. Results of the inspections are documented in NRC Inspection Report 50-483/99-15.

The training provided an overview of the issue, short- and long-term corrective actions, and a review of procedures for ensuring that offsite voltage remained above the minimum requirement. The training was well organized and gave guidance on how to detect a degraded switchyard condition as well as guidance on how to restore offsite power to an operable status.

O8 Miscellaneous Operations Issues (92901)

O8.1 Strike Contingency Planning

a. Inspection Scope (71707 and 92709)

The inspectors assessed the licensee's strike contingency plan.

b. Observation and Findings

In preparation for a potential work stoppage, the licensee developed a contingency plan. The plan was dated October 7, 1999. The plan identified replacement personnel and outlined their responsibilities if a work stoppage occurred. In addition to senior reactor operators that currently stand watch, other personnel from operations and training were identified as replacement operators. The inspectors reviewed the contingency plan and noted that, although replacement operators were qualified, not all routinely stood watch. The inspectors asked if replacement operators were going to be given additional training prior to standing watch to evaluate how they perform as a crew and to give operators an opportunity to work together. The licensee stated that no additional training was planned for the crews prior to assuming watch. The licensee did reconfigure the crews to ensure that only the most qualified individuals would stand watch. No other issues with the contingency plan were identified.

c. Conclusions

In the event of a strike, the licensee did not plan to train replacement operators as crews prior to standing watch. By not training operators as crews, the licensee would miss an opportunity to develop crew team building and an opportunity to evaluate how replacement crews' members interacted with each other and how they performed under normal and emergency situations.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments - Maintenance

a. Inspection Scope (62707)

The inspectors observed or reviewed portions of the following work activities:

P601455	Turbine-driven auxiliary feedwater pump outboard bearing oil inlet switch
P633799	Turbine-driven auxiliary feedwater pump speed controller calibration

b. Observations and Findings

All work observed was performed with the work packages present and in active use. The inspectors inspected the inside of the speed controller cabinet. No dust or debris accumulation was noted. Internal wiring was intact and properly terminated. The inspectors frequently observed supervisors and system engineers monitoring job progress and quality control personnel were present when required.

M1.2 General Comments - Surveillance

a. Inspection Scope (61726)

The inspectors observed or reviewed all or portions of the following test activities:

- Surveillance Procedure OSP-NE-00001B, "Standby Diesel Generator B Periodic Tests," Revision 5,
- Test Procedure OSP-GK-0001A, "A Train Control Room Filtration and Pressurization System Monthly Operability Verification," Revision 0, and
- Surveillance Procedure OSP-NE-00001A, "Standby Diesel Generator A Periodic Tests," Revision 5.

b. Observations and Findings

The surveillance testing was conducted satisfactorily and in accordance with the licensee's approved programs and the Technical Specifications.

M2 Maintenance and Material Condition of Facilities and Equipment

M2 Review of Material Condition During Plant Tours

During this inspection period, the inspectors noted an increasing number of secondary plant steam leaks. The inspectors noted five steam leaks. The valves were:

- AFV00087, first stage reheat drain Tank B emergency drain upstream isolation valve,
- AFV00615, first stage reheat drain tank to high pressure Heater 6B drain valve,
- AFV00538, first stage reheat drain Tank D downstream isolation valve,
- AEV00978, feedwater high pressure Heater 7B pressure relief valve, and
- BMV00077, steam generator nonregenerative heat exchanger tube side drain.

The valves had body-to-bonnet leakage or would not completely seat when closed. The steam leaks did not appear to affect the operation of other equipment in the area. The leaking valves had been identified by the licensee and were prioritized for repair.

III. Engineering

E1 Conduct of Engineering

E1.1 Reactor Coolant System Check Valve and Safety Injection Accumulation Leakage

a. Inspection Scope (37551)

The inspectors followed the licensee's actions in addressing reactor coolant system check valve leakage.

b. Observations and Findings

After starting up from refueling Outage 10, the licensee noted that safety injection Accumulator D level was increasing. Level increased approximately 10 gallons per day. There was no leakage into the remaining three accumulators. There was no increase in safety injection or residual heat removal discharge pressures.

To eliminate the leakage, the licensee systematically isolated manual valves in the safety injection system to identify the source of the leakage. They increased the spring tension closing force on selected air-operated valves in the safety injection test line system.

The licensee narrowed the source of the leakage into the accumulator to two leaking check valves on reactor coolant system Loop 4, Valve EPHV8877D (safety injection Accumulator D isolation valve), Valve EMHV8889A (safety injection Pump B loop hot leg isolation hand valve), and Valve EJHCV8825 (safety injection test line isolation valve). Other valves could also be leaking.

The licensee placed the safety injection test regulator in service. The regulator was controlled by Procedure OTN-EM-00001, "Safety Injection System." Placing the regulator in service caused leakage into the accumulator to divert to the recycle holdup tank. This eliminated the operator work-around of draining the accumulator to maintain the level required by Technical Specifications.

Following isolation of manual valves, increasing spring tension closing force, and installation of the test regulator, leakage to the recycle holdup tank was reduced to approximately 0.25 gpm.

Leakage into the accumulator stopped when the test regulator was placed in service. With Valve EPHV8877D (safety injection Accumulator D isolation valve) leaking by, approximately 2 to 3 gallons of water per day are now being lost from the accumulator.

This valve is scheduled to be repaired during refueling Outage 11. The inspectors asked if there was a concern that leakage out of the accumulator could cause nitrogen voids in the safety injection and residual heat removal systems' piping. The inspectors also asked if there was a program to monitor nitrogen accumulation. The licensee stated that they did not have a nitrogen monitoring program and any nitrogen accumulation concerns were mitigated because each month the safety injection and residual heat removal systems were vented. In November 1999, December 1999, and February 2000, no gas was noted while venting. However, in January 2000, gas was noted in two locations in the residual heat removal system and one location in the safety injection system. The licensee stated that the gas could have been from the accumulator but, since it was not analyzed, its exact source could not be determined. The licensee indicated that if gas continues to be observed, the venting frequency would be increased.

The licensee's venting procedure required an analysis to be performed if gas was vented for approximately 30 seconds from a vent location. If 30 seconds of gas was vented, the procedure only required the chemistry department to sample for hydrogen, not nitrogen. The procedure then required that the surveillance completion form be forwarded to engineering for review and trending. In January 2000, 9 seconds was the longest that gas was vented from any location. The inspectors asked what the basis was for the 30 second requirement. The licensee did not have a basis for the 30 second requirement.

To prevent leakage to the recycle holdup tank and to stop leakage from safety injection Accumulator D, the licensee planned to install a manual isolation valve downstream of Valve EMHV8889A (safety injection Pump B Loop 1 hot leg injection valve) during this cycle. Once the manual isolation valve was installed, the licensee planned to remove the safety injection test regulator from service. This issue was being tracked under Suggestion-Occurrence-Solution Report 00-00026.

c. <u>Conclusions</u>

The licensee was experiencing approximately 2 to 3 gallons leakage from a safety injection accumulator per day. Leakage from the accumulator was occurring through an accumulator test line. The licensee has been proactive in their attempts to stop the leakage from the accumulator and the reactor coolant system. The licensee does not have a program to monitor for nitrogen voids in the safety injection system and the residual heat removal system piping. The current guidance for venting the safety injection and residual heat removal systems did not require the licensee to take any action unless 30 seconds of gas was vented from a vent location. The licensee did not have a technical basis for the 30 second criteria. The licensee planned to install a manual isolation valve in the safety injection test line system to prevent leakage from the accumulator and to stop leakage past reactor coolant system check valves.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Licensee Event Report 50-483/98003-01: inadvertent actuation of the engineered safety features actuation system due to high water level in Steam Generator A during refueling Outage 9.

This licensee event report was initially discussed and closed in NRC Inspection Report 50-483/98-12, issued August 12, 1998. On May 12, 1999, the licensee revised their corrective action to prevent recurrence and issued Revision 1 to the licensee event report. Originally the licensee stated that Procedure OSP-AE-V0003B, "Feedwater Supply Check Valve Closure Test," would be revised to jumper out the feedwater isolation signal during Mode 5 surveillance testing to prevent this signal from occurring. This signal was not required to be functional during Mode 5. The May 1999 submittal indicated that Procedure OSP-AE-V0003B would be revised to incorporate a lower initial steam generator level condition for nitrogen addition to reduce the potential for a feedwater isolation signal actuation. The inspectors had no further concerns.

E8.2 (Closed) Licensee Event Reports 50-483/99009-00 and 50-483/99009-01: reactor coolant system leakage detection system is outside design basis because a 1 gpm leak may not be detected within 1 hour.

This issue was discussed in NRC Inspection Report 50-483/99-14. This report discussed the failure to take corrective action when it was identified that the containment normal sump measurement and containment air cooler condensate flow rate system may not be able to detect a 1 gpm leak within 1 hour as required by the Updated Final Safety Analysis Report. This discrepancy was initially identified in 1997.

Although the discrepancy was identified in 1997, the licensee failed to report that the plant was outside its design basis as required by 10 CFR Part 50.72(b)(1)(ii)B. Failing to report that the plant was outside its design basis was a violation. This Severity Level IV violation is being treated as a noncited violation consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation was entered into the licensee's corrective action program as Suggestion-Occurrence-Solution Report 99-3541 (50-483/00001-02).

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 General Comments (71750)

The inspectors observed health physics personnel, including supervisors, routinely touring the radiologically controlled areas. Licensee personnel working in radiologically controlled areas exhibited good radiation worker practices.

Contaminated areas and high radiation areas were properly posted. The inspectors checked a sample of doors, required to be locked for the purpose of radiation protection, and found no problems.

R1.2 Observation of Health Physics' Coverage During Containment Building Walkdown

a. Inspection Scope (71750)

On February 17, 2000, the licensee entered the containment building while at power to perform several maintenance activities. These activities included a general walkdown of the containment building. The inspectors accompanied the health physics technicians and system engineers during this tour in order to assess the radiological controls implemented.

b. Observations and Findings

In preparation for the containment entry, health physics technicians held a prejob ALARA (as low as is reasonably achievable) briefing for all participating individuals. The inspectors assessed this briefing for its thoroughness and compliance with licensee Procedure HTP-ZZ-01102, "Pre-job ALARA Planning and Briefing," Revision 14. The individual presenting the brief identified areas of concern in the containment building from the perspectives of personnel safety, ALARA, and reactor safety. These concerns included heat stress effects on individuals, low dose wait areas, and components that posed a potential reactor trip hazard. The individual specified various elevated radiation areas in containment (e.g., bioshield access doors) and techniques to avoid these areas. Based on these observations, the inspectors found the briefing to be comprehensive and well performed.

The inspectors then accompanied two licensee engineers and two health physics technicians during their tour of the containment building. (This tour was performed for the purposes of a general walkdown in order to look for leaking components and other deficient conditions, obtain temperature data on certain components, and evaluate the steam leakage from a feedwater check valve bypass valve.) The inspectors observed the technicians' compliance with Procedure HTP-ZZ-03100, "Performing Radiation Surveys," Revision 3. Health physics technicians displayed good practices by maintaining visual contact with all individuals in the group and performing radiation surveys ahead of the group as it moved through different areas in containment. This ensured that individuals did not accidentally enter an abnormally high radiation area. The health physics technicians demonstrated good ALARA practices by frequently performing radiation surveys and having members of the group move to lower dose areas.

c. Conclusions

During a containment building entry, health physics technicians demonstrated good ALARA techniques and compliance with the licensee's radiological procedures.

V. Management Meetings

X1 Exit Meeting Summary

The exit meeting was conducted on February 18, 2000. The licensee did not express a position on any of the findings in the report.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

R. D. Affolter, Manager, Callaway Plant
G. N. Belchik, Supervising Engineer, Operations
J. D. Blosser, Manager, Operations Support
D. G. Cornwell, Supervisor, Electrical Work Control
G. J. Czeschin, Superintendent, Training
J. W. Dowling, Supervisor, Electrical Work Control
M. S. Evans, Superintendent, Protective Services
R. F. Farnam, Supervisor, Health Physics Operations
J. W. Hiller, Engineer, Quality Assurance
R. T. Lamb, Superintendent, Work Control
J. V. Laux, Manager, Quality Assurance
G. L. Randolph, Vice President and Chief Nuclear Officer
M. A. Reidmeyer, Supervisor, Regional Regulatory Affairs
R. R. Roselius, Superintendent, Radiation Protection and Chemistry
J. D. Schnack, Supervising Engineer, Quality Assurance Corrective Action
K. C. Schoolcraft, Senior Engineer, Quality Assurance
M. E. Taylor, Manager, Nuclear Engineering
R. C. Wink, Engineer, System Engineering

INSPECTION PROCEDURES USED

37551	Onsite Engineering
61726	Surveillance Observations
62707	Maintenance Observations
71707	Plant Operations
71750	Plant Support Activities
92700	Onsite Follow Up of Written Reports of Nonroutine Events at Power Reactor Facilities
92709	Licensee Strike Contingency Plan
92903	Follow Up - Engineering
93702	Prompt Onsite Response to Events At Operating Power Plants

ITEMS OPENED AND CLOSED

Opened

00000-01	NCV	Failure to correct the out of specification component cooling water surge tank level (Section O4.1).
00000-02	NCV	Reactor coolant system leakage detection system is outside design basis (Section E8.2).

Closed

00000-01	NCV	Failure to correct the out of specification component cooling water surge tank level (Section O4.1).
98003-01	LER	Inadvertent actuation of the engineered safety features system is (Section E8.1).
99009-00	LER	Reactor coolant system leakage detection system is outside design basis (Section E8.2).
99009-01	LER	Reactor coolant system leakage detection system is outside design basis (Section E8.2).
00000-02	NCV	Reactor coolant system leakage detection system is outside design basis (Section E8.2).

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-8064

MAR 14 2000

Garry L. Randolph, Vice President and
Chief Nuclear Officer
Union Electric Company
P.O. Box 620
Fulton, Missouri 65251

SUBJECT: MEETING TO DISCUSS THE AUGUST 11 - 12, 1999, DEGRADED SWITCHYARD VOLTAGE EVENT

Dear Mr. Randolph:

This refers to the meeting conducted in the Region IV office on March 13, 2000. This meeting was related to the causes, circumstances, and corrective actions associated with the August 11 - 12, 1999, degraded switchyard voltage event.

During this meeting you provided your perspective on the event, as well as a schedule for the corrective actions to preclude future similar occurrences. Additionally, the NRC provided a regulatory perspective on the potential generic implications and safety significance of the event.

In accordance with Section 2.790 of the NRC's "Rules of Practice," Part 2, Title 10, Code of Federal Regulations, a copy of this letter will be placed in the NRC's Public Document Room.

Should you have any questions concerning this matter, we will be pleased to discuss them with you.

Sincerely,

Arthur T. Howell, III, Director
Division of Reactor Safety

Docket No.: 50-483
License No.: NPF-30

Enclosures:
1. Attendance List
2. Licensee Presentation

ENCLOSURE 4

Alan C. Passwater, Manager
Licensing and Fuels
AmerenUE
One Ameren Plaza
1901 Chouteau Avenue
P.O. Box 66149
St. Louis, Missouri 63166-6149

J. V. Laux, Manager
Quality Assurance
Union Electric Company
P.O. Box 620
Fulton, Missouri 65251

Jerry Uhlmann, Director
State Emergency Management Agency
P.O. Box 116
Jefferson City, Missouri 65101

ATTACHMENT 1

ATTENDANCE LIST

MANAGEMENT MEETING ATTENDANCE

LICENSEE/FACILITY	Callaway / Ameren UE
DATE/TIME	March 13, 2000 1:00 pm
CONFERENCE LOCATION	Region IV Executive Conference Room

LICENSEE REPRESENTATIVES

NAME (PLEASE PRINT)	ORGANIZATION	TITLE
Mark D. Haag	Callaway UENE	Senior Design Engr.
Paul J. Nauert	Ameren Services Transmission Planning	Manager
Garry L. Randolph	Ameren UE	Vice President and Chief Nuclear Officer
Michael E. Taylor	Ameren UE	Manager, Nuclear Engineering
RON AFFOLTER	AMEREN UE	PLANT MANAGER-CALLAWAY
Scott Sandbothe	Ameren UE	Supt. Operations
David Waller	Ameren UE	Supv eng Design-Callaway
MARK A. REIDMEYER	Ameren UE	Regional Regulatory Affairs Supervisor
A.K. KRAINIK	APS- PALO VERDE	DIRECTOR - REGULATORY AFFAIRS
W.E. Mookhoek	STP Nuclear Operating Co.	Licensing Engineer.
IJAZ AHMAD	TXU - Electric CPSES	Design Base Engineering
DON WOODLAN	TXU - Electric CPSES	Docket Licensing Manager
[illegible]		

NRC REPRESENTATIVES		
NAME (PLEASE PRINT)	ORGANIZATION	TITLE
VINCENT G. GADDY	NRC	SRI
Jeffrey L Shackelford	NRC	SRA
Elmo Collins	NRC RIV DRP	Deputy Dir. DRP
Ellis Merschoff	NRC RIV	Regional Administrator
Art Howell	NRC RIV	Director, DRS
W.D. Johnson	NRC/RIV/DRP	Chief, Project Branch B

ATTACHMENT 2

LICENSEE PRESENTATION

Ameren

Transmission System Perspective

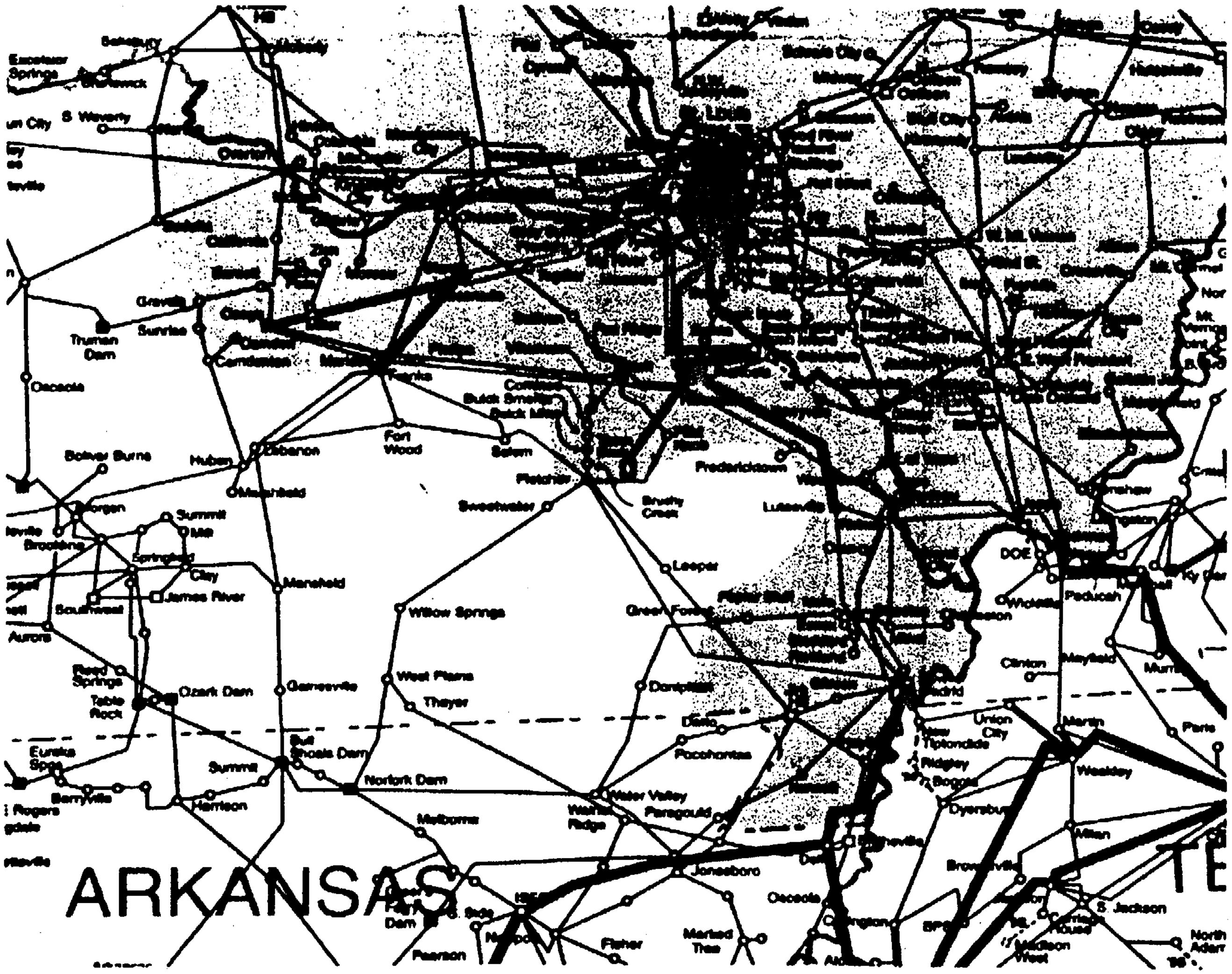
- Impact of Open Access
- August 1999 Switchyard Voltage Event
- Immediate Corrective Actions & Results

Ameren

Area Transmission - Orange=500kV Red=345kV Black=161 & 138kV

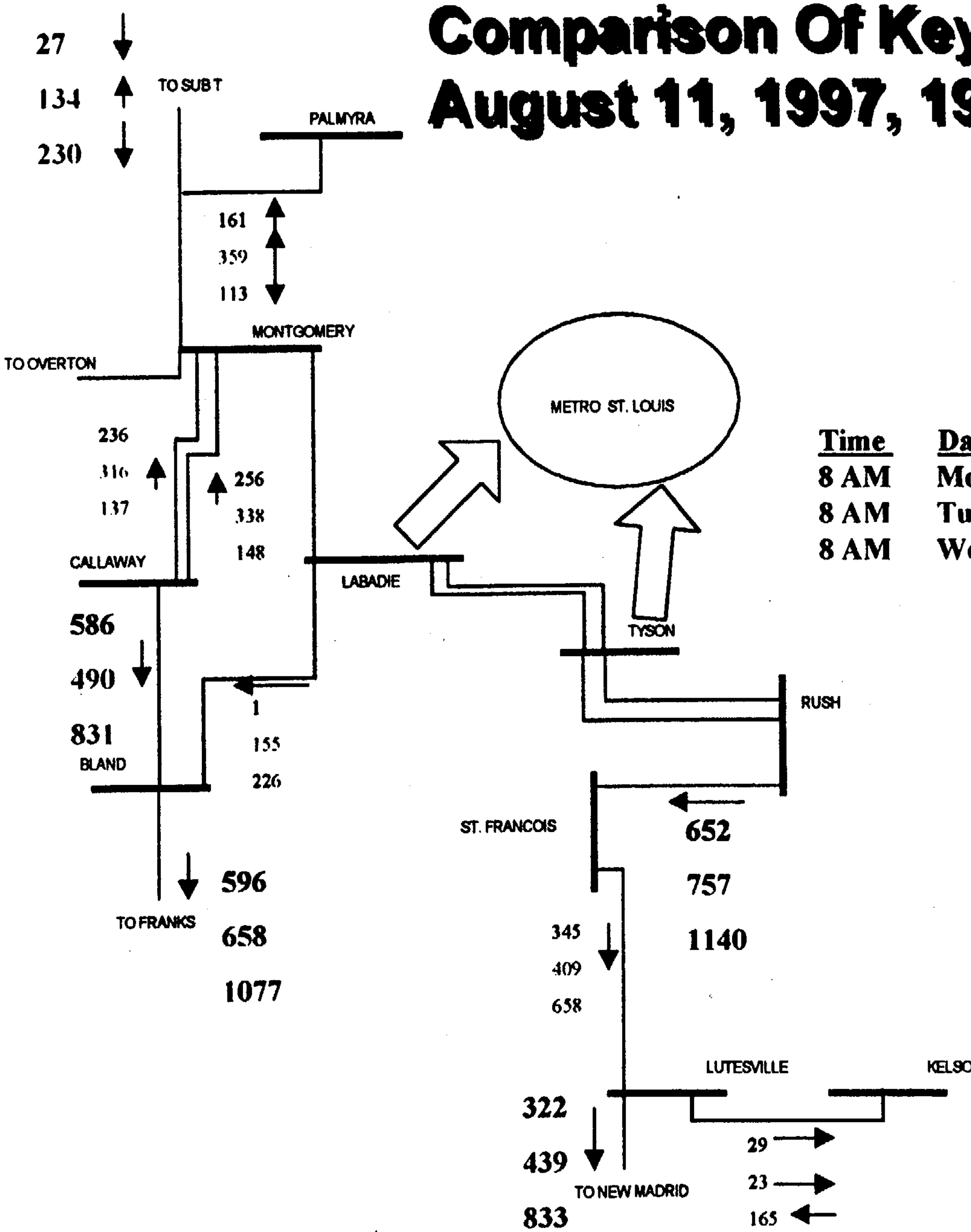
Bland-Franks

Rush-St. Francois-Lutesville



Ameren

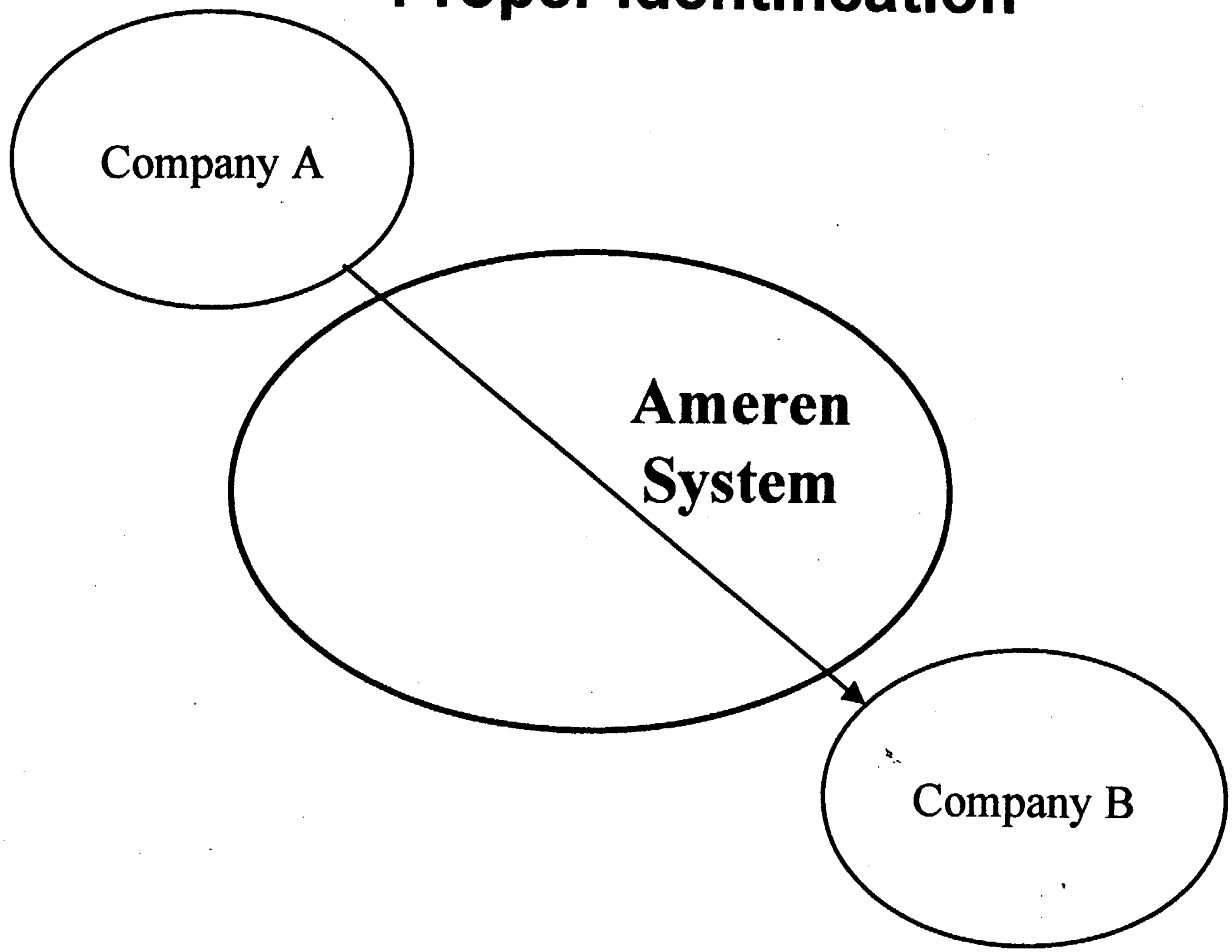
Comparison Of Key 345 kV Line Flows August 11, 1997, 1998, and 1999



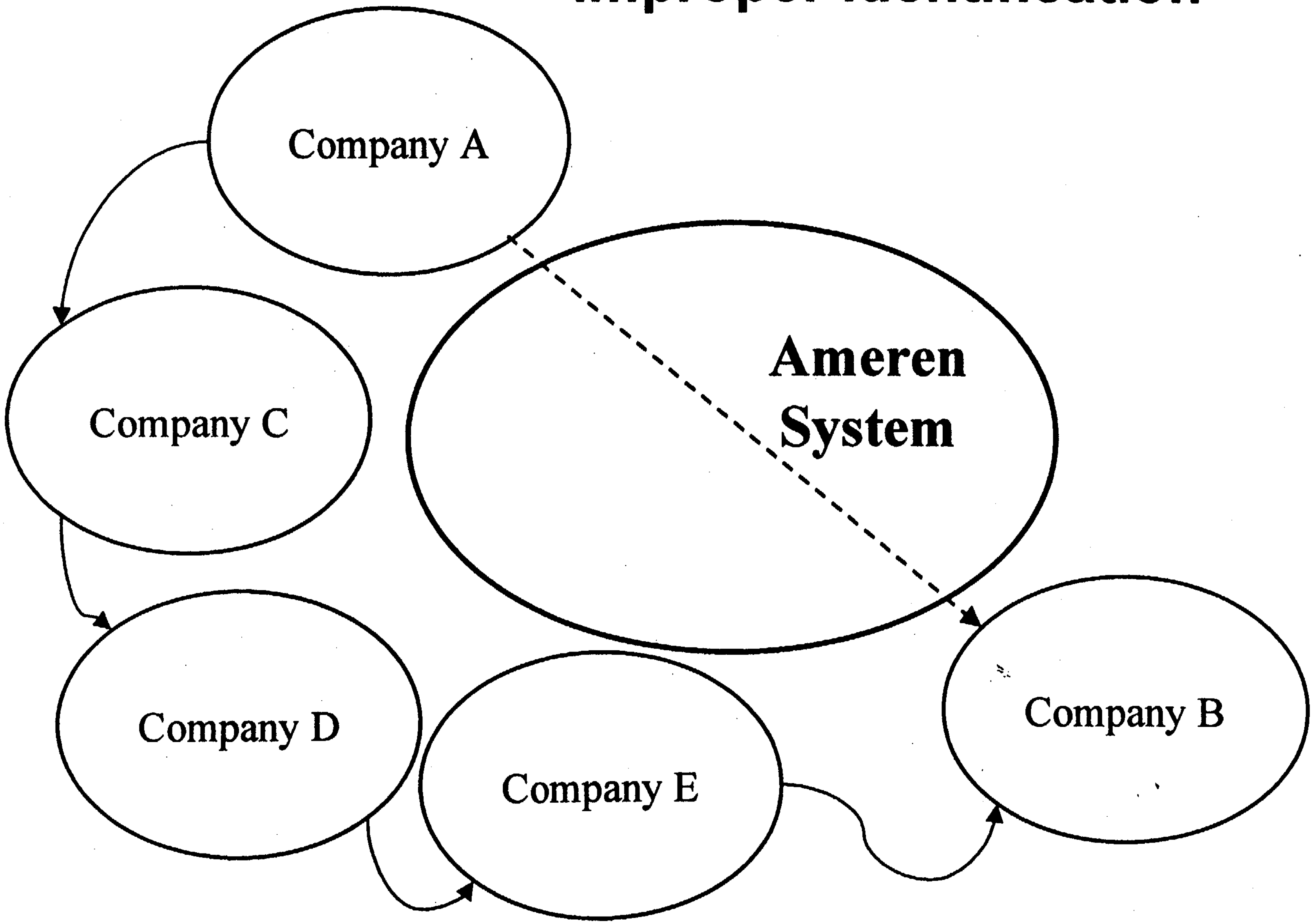
Time	Day	Date	Ambient Temp(Min/Max)
8 AM	Mon	8/11/97	73/89
8 AM	Tues	8/11/98	74/84
8 AM	Wed	8/11/99	71/87

Interchange Transactions

Proper Identification



Interchange Transactions
Improper Identification



Ameren

PROBLEM

- Low switchyard voltage on August 11 and 12, 1999
- Ameren transmission grid voltage has a greater range
  - Open access has caused power wheeling across the Midwest to increase at near peak demand.
  - Ameren system demand is increasing

Ameren

PROBLEM

– Result:

Reduced grid voltages increase the potential for INOPERABLE offsite power sources.

- Ameren does not have complete control over the causes.
- Inadequate administrative controls

Ameren

CORRECTIVE ACTIONS

- Ameren identified causes, provided new analysis, and revised procedures to address concern.
- Callaway Plant/ESO implemented a process to use an on-line predictive computer analysis program to identify potential INOPERABILITY in the event of a main generator trip.

Ameren

CORRECTIVE ACTIONS

- Internal Transmission Provider / Nuclear Site Agreement
- Revised Operations and Energy Supply Operations Procedures to incorporate:
  - Full implementation of contingency analysis computer.
  - Line-up specific voltage acceptance criteria.
  - Instrumentation inaccuracy

Ameren

CORRECTIVE ACTIONS

- Added Switchyard low voltage annunciator.
- Added independent review sign-off to computer software changes.
- Created training lesson and provided training to all operating crews on degraded voltage issues and use of contingency computer information.

Ameren

OPEN CORRECTIVE ACTIONS

- Callaway can accommodate a wider range of system voltages by installing voltage correction equipment.
  - Initial modification - capacitor banks (Spring 2000)
  - Final modification - Load tap changing transformers and capacitor banks (Spring 2001-Refuel 11)

Ameren

OPEN CORRECTIVE ACTIONS

- Expand transmission provider agreement to include other FSAR commitments (due Summer 2000)
- Complete and Review Summer 2000 System Study (due May 2000)

Ameren

SIGNIFICANCE

- Risk Significance Low - Incremental core damage probability 2.24 X 10 -7 (36 hours of potential inoperability over a 22 month period)

Ameren

CONTROL ROOM OPERATOR PERSPECTIVE PAST HISTORY

- 1995 Reactor Trip
  - Switchyard low voltage annunciation not available.
- 1998 NRC Engineering Inspection SOS 98-3526
  - Created computer points for low Switchyard voltage.
  - Requested a modification for a MCB low switchyard voltage alarm.

CONTROL ROOM OPERATOR PERSPECTIVE PAST HISTORY

1999 August Extraction Steam Break Reactor Trip SOS 99-1617

8/11/99

- Loss of the Plant Computer
- Computer down logs inadequate.
- No alarms when the computer was restored.

8/12/99

- Switchyard low voltage computer points alarmed.
- Operators did not use plant computer information.
- Computer alarms were set non-conservative.

8/26/99

- ESO provided single annunciation of Callaway's voltage (category 8 alarm).
- Operations procedures not updated for the category 8 alarm.

Ameren

CONTROL ROOM OPERATOR PERSPECTIVE CURRENT STATUS

- Real Time Contingency Analysis Computer program (category 8 alarm)
- Formal agreement between Energy Supply Operations and Callaway Plant
- Revised procedures to include the category 8 alarm
- Modified Computer Down Logs
- Completed MCB annunciator modification
- Plant Computer Alarms
- Operations training completed

Ameren

ELECTRICAL DISTRIBUTION SYSTEM CALCULATIONS: Transmission Planning PAST PRACTICE

- Load Flow Analysis Performed Upon Request
- Regional Summer Peak Load Flow Base Case Used
- All System Changes Anticipated for Upcoming Summer Included in Base Case
- Scenario Analyzed
  - Dual ESF Source Contingency Only
- No Sensitivity to System Parameters

Ameren

ELECTRICAL DISTRIBUTION SYSTEM CALCULATIONS: Transmission Planning CURRENT PROCEDURE

- Signed Agreement Specifying Frequency and Content of Analysis
- Load Flow Analysis Performed Prior to Each Peak Season
- All System Changes Anticipated for Upcoming Season Included in Base Case
- Analysis to be Reviewed for All Subsequent Significant System Changes

Ameren

ELECTRICAL DISTRIBUTION SYSTEM CALCULATIONS: Transmission Planning CURRENT PROCEDURE

■ Scenarios Analyzed

- Dual ESF Source Contingency Number 1
  - Callaway Off with LOCA loads
  - Callaway-Bland 345 kV Line Open
  - One Callaway-Montgomery 345 kV Line Open
- Dual ESF Source Contingency Number 2
  - Callaway Off with LOCA loads
  - One 600 MW Labadie Unit Out of Service

Ameren

ELECTRICAL DISTRIBUTION SYSTEM CALCULATIONS: Transmission Planning CURRENT PROCEDURE

- Single ESF Source Contingency
  - Callaway Off with LOCA Loads
  - No Transmission System Contingencies

- Sensitivity to Significant Cross System Transfers Included
- Results Reported to Callaway and ESO

Ameren

CALLAWAY/ENERGY SUPPLY OPERATIONS INTERFACES

- Transmission provider agreement in place
- Callaway will be notified of significant changes to system characteristics
- Callaway Control Room notification within 15 minutes of out-of-range voltage
- Callaway-initiated Spring/Fall discussions of system characteristics and model updates

ROOT CAUSE

- SOS 99-1617 was initiated August 13, 1999 for the post trip degraded voltage condition at Callaway Plant.
  - Extensive, immediate response from the plant staff and Energy Supply Operations restored switchyard voltage within limits.
  - Resources were redirected from Refuel 10 to pursue permanent remedies to the concern.
  - QA supervisor determined a formal root cause was not required because of extensive Engineering root cause evaluation.

Ameren

ROOT CAUSE

- Rapid Redesign implemented a Screening Team for new corrective action documents.
  - Screening Team determines priority and need for formal root cause daily.
  - Screening Team was instituted late November 1999.
  - QA supervisor is member of the Screening Team.
- QA Department organization change January 2000 assigned additional personnel to support completion of formal root causes.

Ameren

OPERATING EXPERIENCE

- ISEG initiated SOS 99-2054 September 1999 to address NRC Information Notice 98-07.
  - LER 99-005-00 preparation identified Information Notice had been distributed for information only.
  - ISEG reviewed all Information Notices that were routed for information only since late 1996.
  - Four Information Notices were identified requiring additional review.

Ameren

OPERATING EXPERIENCE

- In January 1999 the responsibility for review of Information Notices was transferred to the ISEG from the Regulatory Operations group.
  - ISEG engineers are experienced and typically cross-trained as STAs.
  - ISEG is also responsible for INPO Operating Experience Program at Callaway Plant.
  - ISEG personnel are located on-site and are familiar with plant programs and processes.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 132 TO FACILITY OPERATING LICENSE NO. NPF-30

UNION ELECTRIC COMPANY

CALLAWAY PLANT, UNIT 1

DOCKET NO. 50-483

1.0 INTRODUCTION

By letter dated October 27, 1998, as supplemented by letters in 1999 dated January 11, January 29, February 25, April 7 (two letters), and May 17, Union Electric Company (UE or the licensee), requested changes to the Technical Specifications (Appendix A to Facility Operating License No. NPF-30) for the Callaway Plant, Unit 1. The proposed changes would revise TS 4.4.5.4, Table 4.4-3, and the associated Bases to allow Callaway Plant, Unit 1 steam generator tubes to be repaired with Electrosleeves. As discussed in this safety evaluation, this amendment includes a two cycle operating limit that requires all steam generator tubes repaired with Electrosleeves to be removed from service at the end of two operating cycles following installation of the first Electrosleeve in the Callaway Plant, Unit 1 steam generators. This limit was agreed upon by the licensee and included in the amendment application dated October 27, 1998.

The supplemental letters in 1999 dated January 11, January 29, February 25, April 7 (two letters), and May 17, provided additional clarifying information and did not change the staff's original no significant hazards consideration determination or expand the scope of the original Federal Register notice published on December 2, 1998 (63 FR 66604).

2.0 BACKGROUND

2.1 Amendment Application

The licensee's amendment application dated October 27, 1998, requested changes to the Callaway Plant, Unit 1 technical specifications (TSs) to allow the use of a new technology for the repair of degraded steam generator (SG) tubes. The method is called Electrosleeve, a structural nickel plating applied to the inside of a degraded tube to form a tube sleeve. Electrosleeve is the trade mark name for the proprietary nickel plating technique for tube sleeving developed by Ontario Hydro Technologies (OHT). It is marketed for commercial use in the United States by Framatome Technologies, Inc. (FTI). The intent of the repair is to install sleeves that would remain in service for the remaining life of the steam generators.

The licensee originally requested approval of the Electrosleeve repair method in an amendment application dated April 12, 1996. In the review of this amendment application, the staff identified a number of issues, including qualification of non-destructive examination techniques planned for inservice examination of the Electrosleeves. The staff's concerns were identified in a letter from S. Collins to G. Randolph dated May 20, 1998. In response to this letter, the licensee submitted an amendment application dated October 27, 1998, which superceded the April 12, 1996, amendment application. The October 27, 1998, amendment application included FTI Topical Report, BAW-10219, Revision 3, dated October 1998.

The October 27, 1998, amendment application proposed that Electrosleeves be installed, inspected and plugged based on criteria delineated in previous submittals, but the length of in-service operation would be limited to two cycles. Specifically, all Electrosleeves shall be removed from the SGs two cycles after the outage Electrosleeves are first installed at Callaway Plant, Unit 1. This limit was proposed due to the staff's concern that the nondestructive examination technique does not ensure acceptable structural safety factors are maintained and, therefore, future inservice inspections may not adequately identify structurally significant flaws. In the October 27, 1998, amendment application, the licensee committed to removing from service all tubes with Electrosleeves at the end of two cycles following installation of the first Electrosleeve, unless a subsequent license amendment request had been submitted and approved by the staff without limitations on the in-service length of operation.

2.2 Electrosleeve Description

An Electrosleeve is a formed-in-place tube sleeve. Inflatable dams and an electrode are inserted into the defective tube and positioned at the location of the tube defect. The plating solution is pumped into the zone defined by the inflatable dams and the electroplating is commenced. After sufficient time to build up the required plating thickness, the process is stopped, the plating equipment removed and the deposited sleeve is inspected for acceptance. An Electrosleeve is either four or eight inches in length depending on the type and severity of degradation the sleeve has to span. A single tube may be plated in one or several locations. The plating process is able to span the typical service induced defects found in SG tubes.

The deposited plating is a proprietary nickel alloy, composed of nickel with a small amount of an alloying element. The grain size is much smaller than that of conventional forged nickel alloys, and, due to the extremely small size, the material is referred to as nanocrystalline nickel. The small grain size enhances the materials' mechanical properties and corrosion resistance.

Extensive analyses and testing were performed on the electroformed material and resulting sleeves. These tests were designed to demonstrate that regulatory requirements were satisfied for both the material and the resulting sleeves. The specifics of the Electrosleeve process, along with the engineering design parameters for the sleeves were originally detailed in a proprietary Framatome generic topical report, "Electrosleeving Qualification for PWR Recirculating Steam Generator Tube Repair," BAW-10219P, Revision 1, dated March 1996. Revision 3 of the topical report was submitted to the staff in the amendment application dated October 27, 1998. Repair of SG tubes by structural electroplating is also described in American Society for Mechanical Engineers (ASME) Code Case N-569. This Code case is not presently endorsed by the NRC.

The following methodology and qualification evaluations were used to qualify the Electrosleeve:

- Define the design requirements for the steam generator tube repair,
- Develop the applicable material properties per the requirements of the ASME Code, Section III,
- Evaluate the tube repair to the possibility of corrosion (primary and secondary side environments),
- Prepare a design analysis of the tube repair per the requirements of the ASME Code, Section III,
- Develop nondestructive examination techniques for the tube repair, and
- Evaluate the tube repair to the requirements of the NRC Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes."

Conventional tube sleeving processes involve the insertion of a smaller diameter tube, the sleeve, into the degraded tube. The sleeve is positioned to bridge the defective area of the tube. The sleeve is then rolled or welded to the tube to form the structural joints. This process has been used for years. However, it has a few limitations. One is the impracticality for installing additional tube sleeves above an existing sleeve due to the access problem created by the first sleeve blocking the path for installing a subsequent sleeve. Additionally, the rolling process used to install some sleeves in the past has created new initiation sites for further tube degradation because of the residual stresses resulting from installation. Welded sleeves are potentially susceptible to stress induced degradation also, because of the residual stress caused by welding or heat treating when a tube is axially constrained at the tube support plates.

A plating operation (e.g., Electrosleeve) does not involve any cold work of the substrate or introduce any significant residual stress. Thus, the potential for subsequent stress induced degradation is reduced compared to conventional sleeving processes.

Plating is generally thought of as a barrier coating to protect against corrosion. The structural uses of plating have not been widespread and have been employed generally for wear resistance. The principal difference between the two plating types would be in the properties and thickness of the plating. Changes in the plating material properties are achieved by choice of alloying elements added to the metal salts used in the plating baths. Plating thickness is controlled by the duration of the plating process.

3.0 <u>EVALUATION</u>

3.1 <u>Process Description and Installation Procedures</u>

The licensee developed a Sleeve Procedure Specification (SPS) which defines the generic requirements for field installation of the Electrosleeves. The licensee stated the SPS was prepared following the guidelines of the ASME Code Section XI for SG tube sleeving and helps control essential and non-essential process variables. A summary of the installation process is as follows:

- Pre-installation eddy current inspection which identifies which tubes are to be repaired,
- Surface cleaning/preparation through mechanical cleaning and application of an electrolyte which enhances the electroplate adherence to the tube inner diameter ,
- Electrochemical deposition of the nickel material,
- Post-installation (preservice) nondestructive examination.

The licensee can verify the sleeving process in-situ by simultaneously electroplating a witness tube (a tube located in a test rig outside the steam generator) which can later be sectioned and examined for acceptance. In addition, process controls and on-line monitoring during the electro-deposition process allow operators and quality control personnel to confirm process variables in accordance with ASME Code requirements.

The staff reviewed the general installation process steps and methods of monitoring and verifying the adequacy of the sleeving process, and concluded the Electrosleeve process and monitoring activities are adequate for controlling essential and non-essential process variables in accordance with ASME Code requirements.

3.2 Material Properties

Electro-deposited nickel is not presently a material of construction listed in a staff endorsed ASME Code Edition or Code Case. Consequently, the material was reviewed for compliance with appropriate Code requirements and guidance for qualifying new materials of construction for use in ASME Code Section III, Class 1 pressure boundary service. The licensee performed testing of the sleeve material in accordance with ASME Code Section III methodologies and American Society of Testing and Materials (ASTM) standards to determine the suitability of the material properties of the Electrosleeve and its use as steam generator sleeve material. A summary of the testing performed on the Electrosleeve follows.

The licensee performed tensile tests using ASTM methods at several temperatures to document yield strength, ultimate strength, and elongation of the electrochemically deposited nickel material. The licensee evaluated this data in accordance with the ASME Code Section III to establish design properties for the nanocrystalline nickel material at a range of temperatures, including operating temperatures.

Multiple specimens were tested in accordance with ASTM procedures to determine the modulus of elasticity. The results showed the modulus of elasticity for the electrochemically deposited nickel material is independent of tube size.

Multiple specimens were bend tested by the licensee in accordance with ASTM procedures to verify the ductility and adhesion of the electrochemically deposited nickel material to the parent tube material. The ductility and adhesion characteristics were verified and deemed acceptable.

The licensee performed fatigue testing on multiple specimens in accordance with ASTM procedures. Tests were conducted at room temperature and elevated temperatures. The licensee concluded the material maintains its fatigue resistance in the temperature range tested.

Thermal stability of the Electrosleeve material is important because of its long-term thermal exposure to high temperatures. The licensee's test results demonstrated the Electrosleeve material is fully stable at pressurized water reactor (PWR) design temperatures and at lower operational temperatures. Testing also indicated the Electrosleeve material is not susceptible to strain-induced recrystallization.

A series of constant load creep tests were performed using ASTM procedures to determine the creep behavior of the Electrosleeve material. Tests were performed at multiple temperatures to evaluate the influence of temperature. Based on the creep test results presented in the topical report (BAW-10219, Revision 3), the creep failures were ductile in nature with no evidence of grain boundary cavitation or fracture in the fracture surfaces.

The licensee performed burst testing on multiple Electrosleeve specimens. The results indicate the sleeve material burst pressures can be calculated by classical burst pressure formulas.

The staff reviewed the information provided in the topical report and determined that the Electrosleeve material was appropriately tested in accordance with ASME Code and ASTM standards and concluded the material was acceptably qualified for use in steam generator sleeves.

3.3 Corrosion Evaluation

The objectives of the licensee's corrosion evaluation were to determine the susceptibility of the Electrosleeve material to known Alloy 600 degradation mechanisms, such as stress corrosion cracking (SCC), and to evaluate the corrosion potential of the material in environments that might exist in an operating SG. The corrosion evaluation was performed by addressing general corrosion first, followed by evaluation of primary and secondary side environments. As discussed in the following sections, the licensee concluded the Electrosleeve material performed very well in that the development of stress corrosion cracking and several other forms of degradation are not anticipated. The topical report described the test environments and, based on experience and knowledge, the staff agrees with this statement. In addition, the licensee concluded the Electrosleeve material performed far better than the current Alloy 600 tube material.

In addition to testing, the licensee performed a literature review of nickel corrosion and found that, in general, both nickel and its alloys effectively resist attack in acid, neutral and alkaline conditions. The presence of highly oxidizing species have been found to decrease this resistance in some chemical environments (e.g., an environment containing sulfur species). The licensee determined a galvanic attack between pure nickel and Alloy 600 will not occur in SG environments due to the low potential difference generated by the formation of a coupling of these two materials.

3.3.1 General Corrosion Properties

The licensee indicated the test environments used to confirm the general corrosion properties of Electrosleeve material were extremely severe and do not exist in steam generators. However, the corrosion mechanisms, for which testing was conducted, are known problems encountered with Alloy 600 material. The corrosion mechanisms tested included intergranular attack (IGA), SCC, pitting, and crevice corrosion. The licensee followed standard ASTM test procedures.

The corrosion tests performed and respective results were as follows:

- Boiling sulfuric acid IGA test which revealed no evidence of IGA,
- Polythionic acid SCC test which revealed no evidence of SCC,
- Magnesium chloride SCC test which revealed no evidence of SCC,
- Sodium chloride SCC test which revealed no evidence of SCC, and
- Ferric chloride pitting and crevice corrosion test which revealed no evidence of pitting and limited crevice corrosion indicating good overall resistance.

3.3.2 Primary Side Corrosion Evaluation

To evaluate corrosion performance of the Electrosleeve material in the primary side environment, the licensee performed testing which addressed full power operating conditions, shutdown conditions and parent tube with primary water stress corrosion cracking (PWSCC) conditions.

To evaluate full power operating conditions, both pure water and primary water chemistry conditions were tested. Highly stressed hard rolled transition zones and highly stressed reverse U-bend specimens were used in the testing. Also, samples were subjected to temperature and pressure cycling in pure water to induce deformations in the nickel layer. The test samples revealed no cracking or other degradation for the pure water and primary water tests.

The main corrosion concern during primary side shutdown conditions is the presence of boric acid. The effect of boric acid, at various temperatures and concentrations, was evaluated on nickel plating. In addition, Electrosleeves were tested at conditions that simulate oxidizing shutdown crud burst conditions. Measurements of the slight general corrosion, where it occurred in two cases, showed a negligible corrosion rate.

The licensee performed two types of tests to evaluate SCC in the parent tube. The objective of the first test was to verify that a nickel plated layer would prevent SCC in the parent tube at highly stressed regions by providing a protective layer. The objective of the second test was to verify that high residual tensile stresses are not induced into the parent tube at the ends of the sleeve. The first test revealed that even if boric acid is trapped in the crevice of an existing primary side tube crack and the Electrosleeve is installed, no further corrosion attack of the parent tube is expected in addition to no corrosion of the sleeve. The second test verified that high residual tensile stresses are not induced into the parent tube at the ends of the sleeve.

3.3.3 Secondary Side Corrosion Evaluation

Based upon the results of the primary side pure water tests and literature searches regarding the performance of nickel when exposed to industry recommended secondary side water chemistries, there were no concerns regarding the ability of the material to withstand the bulk secondary environment. However the Electrosleeve must be able to withstand the environment that locally forms at the tip of Alloy 600 stress corrosion cracks.

The performance of the Electrosleeve in possible secondary side localized environments was evaluated by exposing the sleeve to extreme environments at elevated temperatures. The environments included high concentrations of active species such as chloride and sulphate, in acidic and alkaline media, and high and low redox conditions. The values of acidity and redox potential for these tests were chosen to accelerate the material degradation and are not present in an operating unit.

3.3.3.1 SSC Propagation Tests

Steam generator tubing, containing outer diameter (OD) initiated cracks, was nickel plated and exposed to secondary side conditions in a mockup. Post-test examination showed no crack propagation into the nickel layer, although the crack propagated through the parent tube to the nickel layer interface.

Alloy 600 tubing, with and without an installed Electrosleeve, in the form of highly stressed C-rings, were used to evaluate the ability of the Electrosleeve to arrest a crack propagating from the tube OD. Testing was performed in an environment known to cause SCC in Alloy 600 material. Examination of the samples after the conclusion of the test revealed no evidence of SCC in any of the sleeves even though the Alloy 600 tube had cracked through-wall to the Electrosleeve material. In addition, there was no evidence of either sleeve disbonding or crack propagation along the interface of the tube and sleeve.

3.3.3.2 Capsule Tests

The objective of this test was to characterize the corrosion performance of the Electrosleeve material in confined conditions of extreme bulk water chemistry. A total of 24 different temperature and environmental combinations were tested.

The conclusion from this test was that the Electrosleeve material will be attacked under highly acidic with highly oxidizing environments. However, the sleeve material is resistant to caustic environments and acidic attack in the absence of oxygen, and the highly oxidizing condition that was tested is not reasonably expected to be present in the bulk medium of the secondary side of the steam generator.

3.3.3.3 Heat Transfer Sludge Corrosion Tests

The objective of these corrosion tests was to assess the corrosion performance of an Electrosleeve when a large area is exposed to the extreme chemistry conditions under a sludge pile. Three bulk water environments were selected to address three different operating scenarios of feedwater contamination: condenser cooling water (lake water ingress), sodium hydroxide, and sulfuric acid. The latter species reflect a serious water treatment system malfunction. Considering water chemistry monitoring and specification requirements, in actuality, none of the three conditions is expected to persist for more than a short time.

For the lake water ingress test, very minor general corrosion occurred at the very end of the time-in-testing. The acid ingress test predictably showed that the nickel was subject to general corrosion with some regions of pitting. The test severity was very high due to a high oxygen level. The general attack of the nickel was stopped or substantially mitigated when oxygen levels were reduced close to normal operating plant levels. This verified that the Electrosleeve material would have good resistance to a credible acidic excursion during operation. Post-test examination of the caustic ingress samples showed minimal localized attack of the Electrosleeve material in accordance with the anticipated performance for nickel. This verified that the sleeve material would withstand a credible caustic excursion during operation.

3.3.4 Staff Evaluation of Corrosion Testing

Nanostructured materials are a new class of materials. Nanostructured nickel has never been used as steam generator tube sleeving material in U.S. plants. Therefore, its behavior in U.S. steam generators is mainly postulated based on results from laboratory tests. The licensee has performed an extensive number of laboratory corrosion tests on the nanostructured nickel used to form the sleeve. The material has performed very well and the licensee has postulated the development of stress corrosion cracking and several other forms of degradation are not anticipated. In addition, the licensee concluded the Electrosleeve material performed far better than the current tube material, Alloy 600. But, the intent of laboratory corrosion tests is to mimic, on an accelerated scale, conditions that may be experienced in field applications. Although such tests are valuable tools for screening candidate materials and are reasonable predictors of a material's performance, they cannot anticipate all actual conditions. Therefore, a material's suspected lack of susceptibility to degradation cannot be entirely relied upon for assuring safe conditions for long-term installation. The staff concludes concurrent application of an effective inservice inspection method is necessary to assure safe plant operation.

In Section 3.5 of this safety evaluation (SE), the staff's assessment of the inservice inspection method is discussed. The main conclusion is that the staff believes that the inspection technique does not ensure that acceptable safety factors would be maintained for all flaw types and that structurally significant flaws would not be identified. Therefore, based on the current inspection capability, the staff cannot approve long-term installation. To address this issue, the licensee proposed that Electrosleeves be installed, inspected and plugged based on criteria delineated in BAW-10219P and the length of inservice operation be limited to two cycles. The staff believes that despite the concerns with the capability of the inservice inspection technique, a two-cycle approach is acceptable based on the corrosion test results and expected corrosion resistance of the Electrosleeve relative to Alloy 600 (i.e., the parent tube material).

3.4 Structural Evaluation of Electrosleeves

A steam generator tube sleeve restores a tube to service by effectively replacing the pressure boundary over a defective region of the original tube. Sleeves are designed such that all postulated loadings associated with internal or external pressure, fatigue, thermal, and seismic events should not compromise the integrity of the steam generator tube. Although

Electrosleeves are fundamentally different from previously approved sleeving methods in that the sleeve is chemically bonded to the tube material over an extended length, the design is such that the sleeve should maintain the margins for structural and leakage integrity consistent with the requirements of the parent tubing. Section III of the ASME Code contains the design requirements for the original steam generator tubes. Because Electrosleeves are proposed as a method to replace the steam generator tube pressure boundary over a specified length of degraded tube, these repairs should also satisfy the requirements in Section III.

The Electrosleeve qualification program combined analysis and mechanical testing to ensure that installed sleeves would be qualified for all recirculating SG designs and their operating conditions. Laboratory testing of the sleeve design was conducted using tubes with a range of diameters applicable to SGs installed in U.S. plants. Different test types were conducted to verify that all postulated loads experienced in service were within the structural capabilities of the sleeves. The structural capabilities for degraded Electrosleeves discussed in the following subsections refer to the flaw sizes that do not incorporate additional allowances for flaw growth and nondestructive evaluation (NDE) uncertainty. The structural limit corresponds to the maximum allowable flaw size that can be tolerated while still maintaining necessary margins of safety. The following summarizes the staff's evaluation of the design requirements and flaw specific structural limits for Electrosleeve repairs.

3.4.1 Assessment of Locked Tube Conditions

SG tube support plates were designed to prevent the lateral movement of all tubes. However, service induced corrosion of SG components and the buildup of corrosion products on the secondary side of the tubing may lead to a condition where tubes cannot freely translate axially through tube support structures within a SG. Tubes, in essence, become locked at tube support plate locations. Such conditions have been detected in SGs that are inservice by measuring the forces associated with removing sections of tubes during plant outages. Differential thermal expansion between a tube and other SG components during normal operating and postulated accident loadings may introduce loads on a tube that would not be realized if it were in an unlocked condition. This is a consequence of the tube support plate support structure expanding (i.e., axial translation) at a different rate than the Alloy 600 tubing under transient thermal conditions. These different rates of expansion give rise to stresses in the tube.

Stresses in locked tubes may also be introduced during the Electrosleeve installation process. Although the Electrosleeving installation method is a relatively low temperature operation, small differences in the thermal expansion coefficients between the parent tube and the Electrosleeve material will produce residual stresses within the Electrosleeve repair. Localized residual stresses in the sleeved region may result in stresses outside of the repaired region in order to maintain equilibrium. Testing was performed to measure the loads introduced into a locked parent tube as a result of the sleeving process. This test was conducted to quantify the additional loads that result from repairing locked tubes with the Electrosleeving repair method.

Testing was performed on different diameter tubes that were rolled and welded into a rigid mockup of a tubesheet and tube support plate. The tubes were instrumented with strain gauges and thermocouples and sleeved in the tubesheet and freespan region. The licensee concluded based on the test results that the residual stresses resulting from the sleeving process are low and not considered significant. The staff has reviewed the results from this testing and confirmed the magnitude of the measured loads through an analytical approach. Based on the results of this assessment, the staff concludes that residual stresses from the Electrosleeving process are low and not a concern for the long-term integrity of either the parent tube or sleeve.

During plant transients (e.g., startup, shutdown), changes in the temperature difference between the SG wrapper or other secondary support structures and the tubes, can lead to elevated axial stresses in locked tubes adjacent to support locations. For example, a locked tube on the periphery of the tube bundle near a tube support plate vertical support may experience an axial load when the tube cools more rapidly than the SG wrapper. The magnitude of the thermal load introduced into a tube is a function of the tube's position with respect to the secondary support structures, the flexibility of the support plate, and the number of other tubes that are locked into the support plate. The licensee completed an evaluation to quantify the locked tube loads applicable to the Callaway SGs. Based on the staff's evaluation of the stress limits and the margin to failure considering the criteria in NRC Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," locked tube loads represent the bounding condition applicable to Electrosleeve repairs. Because these loads act in the axial direction along a tube, circumferentially-oriented cracking and uniform thinning of the tube are the primary modes of degradation affected under locked tube conditions. The staff's evaluation of the structural limit of Electrosleeve repairs relative to these loads is provided in Section 3.4.4 of this SE.

3.4.2 Electrosleeve Capabilities to Withstand Cyclic Loading

A table of design transients was developed for the each of the various SG types. The licensee stated that cyclic load test parameters were developed in accordance with Appendix II of Section III of the ASME Code. Three types of specimens were considered in this phase of the design verification testing: (1) unnotched, "minimum bond specimens", (2) samples containing a one inch long notch extending 30 percent through the thickness of the sleeve, and (3) circumferentially notched (360 degree) specimens with a 30 percent throughwall notch. The testing exposed the specimens to pressure, thermal, and/or axial loads as appropriate to simulate conditions representative of service loadings.

The first phase of the testing used "minimum bond specimens". These specimens consist of a sleeve/tube sample that has all of the parent tube (i.e., Alloy 600) machined away except for a small bond length at each end of the sleeve. The samples were subjected to axial cyclic loads, thermal cycling, and pressure cycling. At the conclusion of these tests, specimens were visually and ultrasonically tested (UT) for bond or sleeve failure. The licensee stated that all specimens were acceptable, with no evidence of degradation.

A series of cyclic load tests were performed on notched sleeves in order to verify an Electrosleeve's resistance to crack propagation with respect to the proposed plugging criteria. Samples with one inch axial or full circumferential notches machined 30 percent into the sleeve wall were tested. The sleeves with axial defects were cyclically tested by internal pressure. The sleeves with circumferential defects were tested with axial loads. The vendor assumed life cycle loads under locked conditions because this represented the bounding condition for Electrosleeve repairs.

Prior to testing, the number of transients expected to occur during normal operation including anticipated transients such as startup and shutdown loadings and reactor trips were determined. Numerous other transients were assumed and accounted for in the analysis. Test loads were developed to allow testing to proceed in steps, with each step representing two years of operating life. The test steps were repeated until the specimens failed or until 40 years of service life was reached. In most cases the specimens reached the equivalent of 40 years of life without failing. The shortest service life anticipated based on the test results was concluded to be in excess of 25 years. The interval between inspections (each refueling outage for degraded sleeves) is far shorter than this conservative estimate of the expected service life. Therefore, the licensee concluded that no fatigue related failures (e.g., leaks) would be expected in service.

The licensee stated that the cyclic load testing of unnotched Electrosleeves was completed in accordance with Appendix II to Section III of the ASME Code. The staff has evaluated the licensee's test program with the requirements specified by the ASME Code for experimental stress analysis. Based on the staff's review of the information presented in BAW-10219P, Revision 3, the testing completed by the vendor does not appear to satisfy the requirements in Appendix II for cyclic testing. In order to properly assess a material's resistance to fatigue damage, it is necessary to construct design fatigue curves similar to those in Appendix I of Section III. Based on the information provided by the licensee, only a limited number of smooth Electrosleeves were subjected to cyclic load testing. The number of tests was insufficient to generate a design fatigue curve for this material. Although the testing may not have been in strict accordance with the requirements of the ASME Code, the staff has determined that fatigue related damage to this material in SG tube applications is not the principal concern that limits its service life. The basis for this conclusion is that the cyclic load test results provide sufficient information to allow the staff to assess an Electrosleeve's resistance to fatigue damage.

Testing of degraded (i.e., notched) Electrosleeved tube specimens under limiting cyclic loading conditions demonstrated that the sleeve material is adequately resistant to the initiation and growth of fatigue cracking. Inspections of the tube specimens representative of sleeve repairs applicable to Callaway after completion of the testing showed no signs of fatigue related failure. These results indicate that Electrosleeves have considerable resistance to cyclic loads that enable them to resist potential fatigue related damage that could develop between extended inspection intervals. Therefore, the staff concludes that Electrosleeves have sufficient resistance to cyclic loading damage for steam generator tube sleeving applications. The requirement to perform periodic sleeve examinations at each inspection will also facilitate the detection of damage due to cyclic loading, if such degradation should appear in the future.

3.4.3 Assessment of Electrosleeve Burst Pressure Margins

Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," indicates that SG tube (and sleeve) repair limits, less allowances for NDE uncertainty and flaw growth should, in part, maintain a margin to burst of 3 under normal operating pressures and 1.4 under postulated accident conditions. In order to demonstrate that a degraded Electrosleeve would retain such margins under the proposed repair limits for axially-oriented, linear defects, the vendor developed a model relating the burst pressure of axially cracked SG tubes to the length and depth of the flaw and completed burst testing of simulated flaws in

Electrosleeves. The empirical model incorporated available burst pressure data from previous studies completed by the Electric Power Research Institute, Babcock & Wilcox, and the NRC via Battelle Labs. The vendor augmented the data set for model development with the burst pressure test data of Electrosleeved tube specimens.

Burst pressure testing involves applying an increasing internal pressure to a test specimen until the sleeve fails by rupture. The vendor conducted burst testing of Electrosleeve samples with the parent tube machined away to leave only the sleeve material for test. This was done to demonstrate acceptable margins for Electrosleeve structural integrity without the parent tube providing reinforcement to the installed sleeve. The objective of these tests were to verify that degraded sleeves would have sufficient structural integrity to withstand a differential pressure of three times normal operating pressure in accordance with the criteria specified in RG 1.121. A margin of three on normal operating pressures is the limiting structural case for tube burst applicable to the Callaway SG tubes. Test specimens were fabricated with two types of defects in the sleeve; axial and pitting flaws. The flaws extended 30 percent to 50 percent into the sleeve wall. Testing was conducted at several temperatures. The licensee reported that the failure pressure of each test specimen exceeded the criteria specified in RG 1.121.

The results of these tests indicate that there is greater than a margin of three for burst between the differential tube pressure associated with normal operation and the measured burst pressure for Electrosleeves. This margin is in excess of the burst pressure margins specified for degraded tubes in RG 1.121. In addition, the calculated burst pressure of degraded Electrosleeves, using the model proposed by the licensee, yields results that are consistent with the guidance for tube integrity margins in RG 1.121. The staff has reviewed the proposed burst pressure model and concluded that it provides an adequately conservative estimation of the Electrosleeve burst pressure. In addition, the staff concludes on the basis of analytical results from the model and testing completed by the licensee that Electrosleeve repairs will maintain adequate margins for burst due to internal pressure loading.

3.4.4 Stress Analyses

Design pressures and nominal sleeve dimensions were used in the determination of a tentative pressure thickness for the sleeve wall. In addition, ASME Code Section III stress limits associated with Service Level A through D are satisfied by the proposed design. The results of the analytical assessments of the stress limits during normal operating and postulated accident conditions indicate that the Electrosleeve design meets the applicable design requirements of Section III of the ASME Code. The staff independently evaluated the stress limits of Electrosleeves and concluded that their design meets all the noncyclic loading requirements of Section III of the ASME Code.

Degraded Electrosleeve minimum thickness requirements were developed in accordance with the guidance provided in RG 1.121. RG 1.121 specifies by reference that the structural capability of degraded SG tubes shall meet the limits included in Section III of the ASME Code. The licensee determined a minimum allowable wall thickness associated with each of the stress limits necessary to ensure adequate margins for tube structural integrity. The limiting load that yielded this structural limit was from stresses associated with tubes locked into tube support plates.

The burst pressure model developed to assess the structural margins for Electrosleeves containing axial cracking could not be utilized to estimate the structural margins of circumferentially flawed sleeves. To address this mode of cracking, the licensee completed an analysis using empirically derived limit load expressions. The staff has assessed the methodology employed by the licensee in the analysis of circumferential flaws by performing its own estimations of the Electrosleeve circumferential flaw structural limits using alternative limit load and failure theories. The results of the staff's evaluation indicate that the structural limit calculated for degraded Electrosleeve tubes is conservative with respect to the limiting circumferential flaw subject to internal pressure loads and axial tensile loads due to tube locking.

The staff notes that the peak thermal expansion loads that form the basis for the structural limit for Electrosleeves are experienced by tubes in the immediate vicinity where the tube support plates are fastened to the SG wrapper. Therefore, only a limited number of tubes may be affected by the high thermal loads. As the distance of a tube increases from rigid secondary support connections to the bundle wrapper, the thermally-induced loads on the tube decrease. Therefore, the majority of the tubes in the Callaway SGs should not experience the locked tube loads considered herein.

3.4.5 Staff Evaluation of Electrosleeve Structural Margins

The Electrosleeve design was evaluated both analytically and experimentally to demonstrate that this repair method will restore the condition of the tube to meet the requirements of the ASME Code. The staff verified that the proposed Electrosleeve design applicable to the Callaway SGs was consistent with the noncyclic stress limits of Section III of the ASME Code. The cyclic load testing described in BAW-10219P, Revision 3, does not appear to satisfy the Code requirements for fatigue testing. However, as stated in Section 3.4.2 an Electrosleeve's resistance to cyclic loading is acceptable for steam generator tube repairs.

The staff also reviewed the licensee's calculations and test results to develop the structural limit for degraded Electrosleeves. The minimum structural limit for all flaw morphologies is used in conjunction with nondestructive testing uncertainties and postulated degradation growth rates to establish a sleeve plugging limit (Section 3.7). An independent assessment of the structural integrity margins associated with degraded Electrosleeves by the staff indicates that the limiting structural limit included in Table 8.5.1 of BAW-10219P, Revision 3, was derived in accordance with regulatory guidance to establish SG tube repair limits. Therefore, the staff concludes that the Electrosleeve repair method is acceptable on the basis that it will provide structural integrity margins consistent with other approved SG tube repairs.

3.5 Non-Destructive Examination (NDE)

The NDE of Electrosleeves is conducted using UT techniques. UT is performed after application of the sleeve (preservice inspection) and during inservice inspections. The purpose of the preservice inspection UT is to examine the sleeved area to determine proper installation. Preservice inspection UT will be performed on all sleeves. The purpose of the inservice inspections is to determine whether service related degradation of the sleeve and pressure boundary portions of the tube behind the sleeve has occurred. Inservice inspection scopes and expansion criteria will be in accordance with the plant's TSs.

The UT examination system, acceptance criteria, qualification efforts and the staff's evaluation of the NDE technique will be discussed in the following sections.

3.5.1 Ultrasonic Testing Examination System

The nondestructive examination of Electrosleeves is conducted using UT techniques. Although eddy current testing is currently a more commonly used method for examining steam generator tubes and sleeves, the licensee found there are significant problems with the use of eddy current techniques for examination of the Electrosleeve repair. The primary difficulty is that the electromagnetic properties of the material limit the ability to discriminate sleeve geometry from degradation, accurately depth size crack-like flaws, and detect less significant degradation using commercially available technology.

The ultrasonic testing system consists of UT data acquisition equipment including a UT probe head, probe motor unit, probe driver, water system, NDE integrated control box and a computer station. The UT probe head contains several transducers for normal beam and axial and circumferential shear wave testing. This combination of transducers enables the analysts to assess the sleeve and applicable parts of the tube for process defects and in-service degradation. Once UT data is collected, it is processed and displayed at the computer station in several different modes for interpretation. Flaw detection, characterization and sizing are performed using C-scans, D-scans, A-scans and profilometry displays.

Normal beam data is used to perform time-of-flight measurements to determine pit depth, tube-to-sleeve disbond and thickness. Shear wave examination data is used to detect and size defects such as SCC. The analysis of shear wave data uses three basic methods to estimate the depth of a crack. The methods are tip sizing, multiple skip method and target motion time-of-flight (TOF). Detection of a crack tip signal is rare in a steam generator tube examination, therefore, the tip sizing method is rarely used. The multiple skip method relies on corner reflectors (i.e., the intersection of flaws with inner diameter [ID] and OD surfaces) for analysis. Before sleeving, a deep OD initiated flaw produces both an OD and ID corner reflector. The addition of ID sleeve material to a tube containing this deep OD initiated flaw eliminates the ID corner reflector. Therefore, after sleeve installation, the multiple skip method is not used to size cracks in the parent tubing. The target motion TOF method is most frequently used for sizing cracks. Combinations of these methods were used for the UT qualification efforts discussed in Section 3.5.3 of this SE.

The licensee is developing two additional techniques to supplement and improve the accuracy of the three shear wave analysis techniques discussed above. The development and qualification of these techniques is still in the preliminary stages and these techniques were not used in the UT qualification efforts discussed in Section 3.5.3 of this SE. Therefore, the NRC staff has not reviewed these techniques in detail. The licensee has verbally stated that these techniques may address concerns the staff has with the current techniques (discussed in Section 3.5.4 of this SE).

3.5.2 Ultrasonic Testing Acceptance Criteria

The UT examinations consist of preservice inspection and inservice inspection acceptance criteria, depending on the purpose of the examination.

The preservice inspection data is analyzed to: verify correct sleeve positioning, thickness and size; ensure adequate sleeve-to-tube bonding by identifying disbonds greater than the maximum allowable; ensure significant sleeve installation defects (e.g., nodules or pits) do not exist; and gather baseline data for future comparisons.

Inservice inspections of Electrosleeves are performed to determine whether service related degradation of the sleeve, pressure boundary portions of the tube behind the sleeve and the sleeve-to-tube bond have occurred in excess of TS allowable limits. The licensee has a TS requirement in TS Table 4.4-3, "Steam Generator Repaired Tube Inspections," to inspect at least 20 percent of all installed sleeves. The licensee has proposed to modify Table 4.4-3 to require an inspection of at least 20 percent of each type of installed sleeve. This proposal is consistent with current industry guidance for steam generator sleeve examinations. In addition to the initial inspection scope, Table 4.4-3 requires the inspection results to be classified and, depending on the classification, may require the performance of additional sleeve inspections. Future sleeve inservice inspection scopes and expansion criteria will be in accordance with these TSs.

3.5.3 Ultrasonic Testing Qualification Efforts

The licensee developed multiple data sets to assess the capability of the UT system. Each of these data sets were developed to address a particular inspection parameter or flaw type, such as: parent tube OD pits; sleeve OD pits; sleeve ID pits; disbonds; varied wall thicknesses; axial and circumferential outside diameter stress corrosion cracking (ODSCC) and PWSCC and IGA. The licensee assessed all data sets (i.e., UT data versus destructive examination data) to determine the probability of detection (POD) and UT sizing capabilities. The UT sizing capability was characterized in terms of average error, maximum error, standard deviation, and UT uncertainty (root mean square error). The UT uncertainties were the values considered by the licensee when determining the plugging limit as discussed in Section 3.7 of this SE.

A normal beam UT examination (for flaw detection and sizing) is required to perform the preservice inspections which determine sleeve thickness and size, sleeve-to-tube bonding, and sleeve installation defects (e.g., pits). Normal beam and shear wave UT examinations (detection only) are required to perform the preservice inspection which determines sleeve positioning. The licensee stated that: (1) all data sets had a high POD, and (2) the normal beam UT uncertainties were sufficiently low for all data sets such that they could be accounted for in the margin between the structural limit and plugging limit.

Normal beam and shear wave UT examinations (for flaw detection and sizing) are required to perform the inservice inspections. The licensee stated that: (1) all data sets had a high POD, and (2) the UT uncertainties for all data sets were sufficiently low such that they could be accounted for in the margin between the structural limit and plugging limit.

3.5.4 Staff Evaluation of Non-Destructive Examination Technique

The licensee has chosen UT as the NDE technique to perform preservice and inservice inspections of the Electrosleeve. The UT technique must be able to detect all flaw types (e.g., volumetric and crack-like) and must be able to disposition all flaws in accordance with the TSs.

The licensee developed multiple data sets to assess the capability of the UT system to detect and depth size all tube/sleeve flaw types (i.e., pitting, thinning, stress corrosion cracking, etc.). The staff reviewed the POD determination, UT uncertainties and the data which supports these values. The staff concluded the licensee could adequately perform the examinations necessary for preservice inspections. The POD, UT uncertainties and the data which supports these values were reasonable and will assure that safety significant flaws would be detected, sized and dispositioned in accordance with TS requirements and that structural limits (see Section 3.7 of this report) will be maintained.

The staff reviewed the examination techniques necessary for inservice inspections and identified concerns with the depth sizing capability of the shear wave examination when sizing stress corrosion cracks. The UT under-call errors were significant when assessing the deepest flaws in the data set. The staff determined the shear wave UT technique does not ensure that structural limits are maintained when depth sizing stress corrosion cracks. This conclusion was previously communicated to the licensee. However, the licensee has proposed a limit of two cycles on the length of inservice operation for all Electrosleeves. The staff believes that despite the concerns with the capability of the inservice inspection technique, a two-cycle approach is acceptable based on the Electrosleeve corrosion test results and the expected corrosion resistance of the Electrosleeves relative to Alloy 600 (i.e., the parent tube material).

As discussed in Section 3.5.1 of this SE, the licensee is developing additional UT analysis techniques to supplement and improve the accuracy of the current techniques. This may enable the licensee to address the NDE issues before the end of two operating cycles.

3.6 Flaw Growth

The licensee performed an evaluation of the corrosion resistance properties of the Electrosleeve material through laboratory testing as discussed in Section 3.3 of this SE. The licensee concluded that general corrosion, crevice corrosion, pitting, stress corrosion cracking and IGA are not a concern when exposed to PWR environments. Despite these conclusions, the licensee made what they considered very conservative estimates on the potential growth rate of all degradation mechanisms in order to obtain data to use in determining the plugging limit. These estimates were mainly based on technical assumptions rather than laboratory data since laboratory data indicated degradation would be negligible or nonexistent. Since the flaw growth rate estimates used in developing the plugging limit are conservative with respect to the laboratory corrosion test results, the staff determined the flaw growth rate estimates utilized by the licensee are appropriate.

3.7 Electrosleeve Plugging Limits

The sleeve is made up of three regions which require different evaluations relative to repair or plugging. These regions are the taper region, the bond region and the "sleeve as pressure boundary" region. In each of these regions, the TS plugging limits apply to that which is part of the reactor coolant pressure boundary (e.g., if both the sleeve and parent tube are part of the reactor coolant pressure boundary, the TS plugging limit for both the sleeve and parent tube would apply).

Taper regions are located at both ends of the sleeve and are where the full thickness of the sleeve tapers off. In this region the parent tube is the pressure boundary. The licensee stated that tube degradation in this region would be dispositioned in accordance with the 40 percent throughwall TS criterion if the degradation was volumetric in nature (e.g., pitting, wastage or wear). If any other tube degradation (e.g., cracking) was identified the tube would be plugged or repaired on detection. Sleeve degradation in this region could be left in-service because the sleeve is not part of the pressure boundary.

There is a bond region at each end of the sleeve next to the taper region. In the bond region, the combined thickness of the sleeve and tube constitutes the pressure boundary. The licensee indicated that tube degradation in this region would be dispositioned in accordance with the 40 percent throughwall TS criterion if the degradation was volumetric in nature. If any other tube degradation was identified the tube would be plugged or repaired on detection. Sleeve degradation in this region would be dispositioned in accordance with the 20 percent throughwall TS criterion.

The "sleeve as pressure boundary" region is in the center of the sleeve and spans the defect in the parent tube. In this region, the sleeve is the pressure boundary. Degradation of the sleeve will be dispositioned in accordance with the 20 percent TS criterion. Degradation of the parent tube is acceptable, as long as it does not extend into the sleeve beyond the sleeve's plugging/repair limit.

In conventional sleeving, typical industry practice is to plug/repair a sleeve upon detection of cracking in any region of the sleeve repair. The plug-on-detection philosophy cannot be applied to flaws detected in the "sleeve as pressure boundary" region of the Electrosleeve. This is because the Electrosleeve bonds to the tube along the entire length of the sleeve and the UT inspection detects the original parent tube flaw regardless of whether the parent tube flaw has extended into the sleeve. The licensee chose to address this issue by depth sizing parent tube flaws and dispositioning the sleeve as pluggable/repairable, if the flaw depth indicates the flaw has propagated into the sleeve beyond the sleeve plugging limit.

Table 12.5.2 of BAW-10219P contains a description of the plugging limit for sleeve ID pits in the bond region and "sleeve as pressure boundary" region. This plugging limit conflicts with the proposed TS plugging limit of 20 percent through the sleeve. To address this, the licensee added a statement to proposed TS Section 4.4.5.4.a.10.b) to state that Electrosleeves would be installed in accordance with BAW-10219P, except the 20 percent plugging or repair limit would apply to ID pits in the bond region and "sleeve as pressure boundary" region. This resolves the conflict and is acceptable to the staff.

The proposed Electrosleeve plugging limit was established in accordance with RG 1.121 and should ensure that all tubes repaired by Electrosleeving will retain acceptable margins for tube integrity from degradation in the repaired tube area. The proposed plugging limit for degradation in the sleeve as pressure boundary region was established by determining the structural limit associated with the most limiting stress margin specified in RG 1.121 and includes allowances for degradation growth and NDE uncertainty. The sleeve will maintain the margins for tube integrity through application of the proposed plugging limit consistent with the tube integrity margins specified in RG 1.121. On this basis, the staff concludes that the proposed Electrosleeve plugging limit is acceptable.

3.8 Leakage Integrity

The Electrosleeve design provides a leak-tight seal for primary-to-secondary water. Leak testing was performed at room temperature on Electrosleeved Alloy 600 tubes. The specimens used in this test consisted of "minimum bond specimens." This is a sleeve/tube sample that has all of the parent tube machined away except for a small bond length at each end of the sleeve. The specimens were subjected to a primary side hydro test at 4200 psig and then a leak test at 2500 psig. No visible leakage was observed. These test results are consistent with the design objective of a leak-tight sleeve.

In addition, the licensee already has a restrictive TS limit on primary-to-secondary leakage of 150 gallons per day per SG. This is in accordance with the staff position regarding primary-to-secondary leakage limits for SGs with sleeves.

3.9 Quality Assurance

In the course of reviewing submittals associated with the Electrosleeving license amendment request, the staff identified several examples of inaccurate data being supplied to the staff, two of which were documented in the staff's December 18, 1997, request for additional information. The licensee responded to this concern in a letter February 24, 1998, and amendment application dated October 27, 1998.

The licensee performed an internal review and determined that the cause for the errors was inadequate independent review prior to submittal of licensing documentation to the NRC. In addition to performing an internal review, the licensee performed an independent Quality Surveillance of the Electrosleeve vendor. The licensee determined that the cause for the vendor's errors was also inadequate independent review of licensing documentation. Both parties provided personnel training to reinforce the procedures and management expectations on the expected level of review of licensing documentation. In addition, it was determined that adequate time and resources had to be provided to personnel responsible for reviewing licensing documentation to enable them to adequately process and review licensing submittals to the NRC.

In addition to the procedural issues discussed above, the licensee and vendor implemented a completely independent review of all licensing submittals associated with Electrosleeving which were previously submitted. Three types of common errors were found in the course of the review: typographical errors; errors transcribing data from a source document to a licensing document; and errors associated with mislabeling units (i.e., mils vs. inches). These errors were corrected and incorporated into the revised topical report. The licensee noted that the correction of the documentation errors did not affect the overall technical conclusions previously documented because those conclusions were reached based on information obtained from the source documents which previously had been determined to be accurate.

The internal audits conducted by the licensee and vendor, and the licensee's independent Quality Surveillance of the vendor appear to be thorough. The root cause was identified and subsequent corrective actions appear to be appropriate. The staff did not identify any further errors in their review of subsequent submittals. Therefore, the staff considers this issue to be adequately addressed.

3.10 Future Considerations

The technical evaluation documented in this SE concludes that a limited two-cycle approach to the installation of Electrosleeves is technically supported and, therefore, acceptable. In order for the staff to approve Electrosleeving without limitations in the future, another license amendment request must be submitted, and the remaining issues from the May 20, 1998, NRC letter to Union Electric would have to be addressed. These issues are as follows.

A significant issue to be dealt with is the staff's concern regarding the UT technique's ability to reliably depth size stress corrosion cracks. Despite the relatively reasonable UT uncertainty for the SCC data set, a review of the data supporting the UT uncertainty reveals significant under-call errors when assessing the deepest flaws in the data set. Therefore, the staff cannot conclude the UT technique can reliably depth size stress corrosion cracks and ensure that structural limits are maintained. This issue is further described in Request for Additional Information (RAI) Question #1 of the May 20, 1998, NRC letter to Union Electric Company.

Several more issues, regarding the UT inspection, UT qualification data sets, a tube pull program and the effect of honing on the Electrosleeve, were raised in the May 20, 1998, NRC letter to Union Electric Company. The staff determined it was not necessary for the licensee to address these issues as part of the two-cycle amendment request, but they need to be revisited if a permanent amendment is requested. The issues dealt with UT inspections from one direction (RAI Question #4), a tube pull program (RAI Question #6), inspection of dented intersections (RAI Questions #9 and 10), additional UT data on pits and disbonds (RAI Question #13), the effect of honing on the Electrosleeve (RAI Question #14) and UT procedures and peer review report (RAI Question #15). The depth to which these issues would need to be addressed is dependent on how the licensee addresses the UT depth sizing of the SCC issue described above.

The staff notes that one of the structural acceptance criterion included in Table 8.5.2, "Electrosleeve Structural Limits Level D Conditions," of BAW-10219P is inconsistent with the guidance provided in RG 1.121. Specifically, RG 1.121 states that the margin of safety against tube failure (i.e., burst) under postulated accident conditions should be consistent with margins of safety specified in Section III of the ASME Code. The NRC has generally accepted a margin of 1.4 against tube rupture. The criterion listed in Table 8.5.2 indicates that the structural limits were calculated without consideration of an additional margin for tube burst. Independent calculations by the staff have verified that the stated structural limits for burst under Service Level D conditions appear to be determined without considering the appropriate factor of safety. Although these structural limits appear to be in error, this does not affect the staff's conclusions stated in this safety evaluation regarding the acceptability of the Electrosleeving repair technique. As discussed in Sections 3.4.1 and 3.4.4 of this SE, the limiting structural loads for Electrosleeve repairs result from tubes locked into steam generator tube support structures under Service Level A conditions. Therefore, the structural limit that forms the basis for establishing the proposed repair limit is more limiting than the value determined by considering burst failure under postulated accident conditions while applying appropriate margins of safety. However, if future conditions are such that the burst pressure under Level D service conditions govern the structural limit for Electrosleeves, the licensee would be required to either modify the topical report to reflect the structural limit determined using margins of safety specified in RG 1.121 or provide a technical basis for the acceptance criterion indicated in Table 8.5.2.

3.11 Proposed Technical Specification Changes

In order to incorporate the proposed changes to permit sleeving of the Callaway SGs using Electrosleeves, the licensee has proposed the following changes to the TSs.

a. Proposed changes to TS 4.4.5.4.a.2) and 4.4.5.4.a.4)

The phrase "or sleeve" is added to the definitions of "Degradation" and " % Degradation" to address degradation of sleeving.

b. Proposed change to TS 4.4.5.4.a.6) "Plugging or Repair Limit"

The definition of "Plugging or Repair Limit" is modified to specify the plugging/repair limit for the pressure boundary region of the Electrosleeve is 20 percent of the nominal wall thickness.

c. Proposed change to TS 4.4.5.4.a.9) "Preservice Inspection"

Administrative change. Deletes the word "and."

d. Proposed new TS 4.4.5.4.a.10)b) "Tube Repair"

The section is added to specify that tube repair using Electrosleeves shall be in accordance with the methods described in Framatome Topical Report BAW-10219P, "Electrosleeving Qualification for PWR Recirculating Steam Generator Tube Repair," Revision 3, dated October 1998. This section also states that the 20 percent TS plugging limit for the sleeve will apply to inner diameter pits in Regions B and C (as defined in the topical report). This clarifies a contradiction between the TS plugging limit for inner diameter pits and the topical report's plugging limit for inner diameter pits. In addition, this proposed new TS section adds a statement that requires all Electrosleeves to be removed from service within two cycles following installation of the first Electrosleeve.

e. Proposed new TS 4.4.5.4.a.11) "Degraded Sleeve"

The section is added to incorporate the definition of a degraded sleeve to specify that a degraded sleeve is any sleeve containing imperfections greater than zero percent but less than 20 percent of the nominal wall thickness caused by degradation.

f. Proposed change to TS Table 4.4-3 "Steam Generator Repaired Tube Inspection"

This table is modified to clarify that each repair method is considered a separate population for determination of the initial inservice inspection scope, as well as scope expansion which is already specified.

g. Proposed revision to TS Bases section

The Bases section is modified to include the plugging/repair limit for the pressure boundary portion of Electrosleeves to be 20 percent of the nominal sleeve wall thickness as determined by NDE.

Based on the evaluation contained in this safety evaluation, the NRC staff concludes the proposed technical specification changes, including the two-cycle limitation, are acceptable.

4.0 STATE CONSULTATION

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

5.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to installation and use of a facility component located within the restricted area as defined in 10 CFR Part 20 and changes surveillance requirements. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant changes 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 (63 FR 66604). 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 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 amendment will not be inimical to the common defense and security or to the health and safety of the public.

Principal Contributors: C. Beardslee
G. Hornseth
P. Rush

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