U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-315/84-18(DRP); 50-316/84-20(DRP)

Docket Nos. 50-315; 50-316 Licenses No. DPR-58; DPR-74

Licensee: American Electric Power Service Corporation
Indiana and Michigan Electric Company
1 Riverside Plaza
Columbus, OH 43216

Facility Name: Donald C. Cook Nuclear Power Plant, Units 1 and 2

Inspection At: Donald C. Cook Site, Bridgman, MI

Enforcement Conference At: Region III Office
Glen Ellyn, IL

Inspection Conducted: June 21, 1984 through August 30, 1984

Enforcement Conference Conducted: September 7, 1984

Inspectors: E. R. Swanson

J. K. Heller

R. J. Leemon

P. R. Wohld

P. L. Eng

Approved By: for G. C. Wright, Chief
Projects Section 2A

10/15/84
Date

Inspection and Enforcement Conference Summary

Inspection on June 21, 1984 through August 30, 1984 (Reports No. 50-315/84-18 (DRP) 50-316/84-20(DRP))

Areas Inspected: Special inspection of the circumstances surrounding three events: the discovery of both trains of the Engineered Safety Features Equipment Ventilation Exhaust System being inoperable; the discovery of both Motor Driven

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Auxiliary Feedwater Pumps being inoperable; the discovery of the Turbine Driven Auxiliary Feedwater Pump not being in a standby condition ready to deliver water to the steam generators on demand. The inspection involved 22 inspector-hours by 5 NRC inspectors.

Results: Three items of noncompliance were identified (both trains of ESFAS Ventilation System inoperable; both Motor Driven Auxiliary Feedwater Pumps inoperable; Turbine Driven Auxiliary Feedwater Pump inoperable).

DETAILS

1. Persons Contacted

   a. Inspection June 21, 1984 through August 30, 1984

      W. G. Smith, Jr., Plant Manager
      K. R. Baker, Operations Superintendent
      J. G. Feinstein, Manager, Nuclear Safety and Licensing
      C. E. Murphy, Operations Production Supervisor
      T. R. Stephens, Operations Performance Senior Engineer
      A. A. Blind, Technical Engineering Superintendent
      J. A. Kobyra, AEPSC, Project Mechanical Engineer
      T. Satzan Sharma, AEPSC, Safety/Licensing
      P. A. Barrett, AEPSC, Nuclear Safety and Licensing

      The inspectors also interviewed other licensee employees, including members of the technical, operations, maintenance, C&I, and corporate staff.

   b. Enforcement Conference September 7, 1984 AEPSC Personnel

      J. E. Dolan, Vice Chairman, Engineering & Construction
      M. P. Alexich, Vice President, Nuclear Operations
      W. G. Smith, Jr., Plant Manager
      R. F. Kroeger, Manager of Quality Assurance
      J. G. Feinstein, Manager, Nuclear Safety and Licensing
      P. A. Barrett, Senior Licensing Engineer
      K. R. Baker, Operations Superintendent
      B. A. Svensson, Assistant Plant Manager
      R. L. Strasser, Senior Training Instructor
      B. H. Bennett, Assistant Manager, Nuclear Operations
      J. F. Stietzel, Quality Control Superintendent

      Other members of the corporate and plant staff were also present.

      U.S. NRC Personnel

      J. G. Keppler, Regional Administrator
      C. E. Norelius, Director, Division of Reactor Projects
      B. A. Berson, Regional Counsel
      W. D. Shafer, Chief, Projects Branch 2
      W. H. Schultz, Enforcement Coordinator
      J. I. McMillen, Chief, Operator Licensing Section
      G. C. Wright, Chief, Projects Section 2A
      J. F. Suermann, Inspection Project Manager, Section 2A
      E. R. Swanson, Senior Resident Inspector
      J. K. Heller, Resident Inspector
      R. J. Leemon, Resident Inspector
      P. R. Wohld, Reactor Inspector
      P. L. Eng, Reactor Inspector

      Other members of the regional staff were also present.

2. Engineered Safety Features Equipment Ventilation Exhaust Inoperable

a. Background

The Engineer Safety Feature (ESF) ventilation exhaust system protects essential pumps from overheating during normal and emergency operation and ensures that radioactive airborne contamination leaking from safeguards equipment located in the pump rooms following a LOCA are filtered prior to reaching the environment. There are two 100% capacity ESF ventilation trains installed in Unit 1 with each train consisting of an air handling unit and fan. The air handling unit consists of three filters: a roll type; an absolute particulate type, and a charcoal type. Each ventilation train will automatically start if any of the components in its associated ESF trains are started.

Technical Specification 3.7.6.1 requires operability of both trains in Mode 1, 2, 3, and 4 but allows inoperability of one train for seven days. When both trains are inoperable Technical Specification 3.0.3 requires the plant to initiate action within one hour to be in Mode 3 in six hours, Mode 4 within the next six hours, and Mode 5 in the next twenty-four hours.

b. Event

Both trains of the ESF ventilation system were inoperable from 1941 hours on June 20, 1984 to 0737 hours on June 21, 1984. Since the plant entered Specification 3.0.3 in Mode 3 and Mode 4 was not achieved in six hours, the Technical Specification was violated. Listed below is a chronology of the events that led to the above situation.

- The plant tripped on June 17, 1984 due to failure of a Control Room Instrument Distribution (CRID) power supply. The plant remained in Mode 3 while the repairs were made.
- The licensee changed the roll filter for air handling unit 1 and noted that a bracket, internal to the air handling unit, would require a weld repair. To facilitate repair, portions of the charcoal filter were removed.
- After repair, an operability test (**12 THP 4030 STP.288) was performed as required by Technical Specification 4.7.6.1.b.1.
- STP.228 prohibits operation of the train that is not being tested due to air flow interference. The personnel performing the test apparently interpreted this to mean, "take the control switch to off", which inhibits the automatic start features.
- At 1941 hours on June 20, 1984 both trains were inoperable - one with the control switch in off and the other inoperable pending satisfactory completion of the test.

- STP.228 was completed but the results were inconclusive needing additional review. During the review the train being tested was left running and the other unit was left in the off position.

- At 0725 hours on June 21, 1984 an operator noted that fan No. 2 control switch was off at which time he questioned the validity of the lineup.

- At 0737 hours on June 21, the operator returned 1 HV-AES-2 to service by placing the control switch to auto.

- At 0820 hours on June 21, 1984 the Operations Superintendent notified the NRC per 10 CFR 50.72.

- An additional retest was performed on June 22, 1984 and the air handling unit was declared operable at 1145 hours.

- The plant was made critical at 1423 hours on June 22.

c. Followup and Evaluation of Safety Significance

Evaluation of this event showed that the safety significance was minor since the fan which was not demonstrated operable was later found to be operable, and it was also operating during the period the other fan was switched off. An operator could have turned on the second fan if needed, but at the time of the event the Emergency Procedures did not require that the operator verify the fan start. This change was implemented September 18, 1984. The significance of this event is that it revealed a lack of control over safety system components by the licensee which resulted in redundant trains being inoperable. The antecedents to this event include:

(1) STP.228 was itself written after violations of surveillance requirements were identified in April of 1982. Previously air flow was not measured after the prefilter was changed resulting in air flow greater than allowed (LERs 315/82-21/036-0; 316/82-34/036-0).

(2) STP.228 was inadequate for conducting the test. No initial conditions were specified, the applicable Limiting Conditions for Operation (LCO) were not referenced (only the surveillance requirement was referenced), no precautions were included, and the procedure was not specific as to how the performer should "Verify that the AES fan being tested is the only one operating ...".

(3) Operators in the control room during performance of the test did not recognize the violation of Technical Specifications created by placing the only known operable fan in the off position. Subsequent shift turnover and panel walkdowns at 2330 on June 20, 1984 also failed to detect the mispositioned switch.

(4) Interviews with Performance Engineers performing testing showed that they generally feel no responsibility for compliance with the LCO, only for the conduct of the test. This may have contributed to the procedure not referencing the LCO or ensuring compliance.

3. Motor Driven Auxiliary Feedwater Pumps Inoperable

a. Background Information

D. C. Cook Technical Specification Limiting Condition for Operation 3.7.1.2 requires three independent steam generator auxiliary feedwater pumps and associated flow paths to be OPERABLE IN Modes 1, 2 and 3. Operability of this system ensures that the Reactor Coolant System can be cooled down from normal conditions to less than 350°F so that cooling by the Residual Heat Removal System can commence. Each of two electric driven pumps is capable of delivering 450 gpm total flow at a pressure of 1065 psig to the steam generators. The turbine driven pump is capable of delivering 900 gpm at the same pressure.

Technical Specification 3.3.2.1, Engineered Safety Features Actuation System Instrumentation, Table 3.3-3 Item 6 requires the following actuation signals to be operable: Steam Generator Water Level Low-Low, 4kv Bus Loss of Voltage (blackout), Safety Injection, Loss of Main Feedwater Pumps.

b. Event

During a tour of the Unit 1 control room at approximately 0800 hours on August 8, 1984 the inspector found the plant in Mode 3 starting up from a short surveillance/maintenance outage (1050 psig and 400°F) with the control switches for both Motor Driven Auxiliary Feedwater Pumps (MDAFP) in an unmarked position. When questioned, the control room operators stated that the "after trip" or "neutral" position prevented automatic starting of the MDAFP when the turbine driven main feedwater pumps are not running. Steam generator makeup water was being supplied by the MDAFP. The MDAFPs were operated as needed to obtain the desired level and then the control switches were placed in neutral. The Plant Heatup Procedure **1-OHP 4021.001.001 Mode 4 to Mode 3 Equipment Check Sheet 5.4 Step 3 requires verification that the control switches are "...in auto or pump running." No further guidance is provided to the operator on switch position. Mode 3 was entered at 0623 hours on August 8 and the pumps were stopped at 0640 (East) and 0658 (West) hours. The MDAFP automatically starts on: Low-low level in any steam generator; safety injection; loss of both main feedwater pumps and blackout signal. Since the neutral position prevented automatic operation of the MDAFP due to loss of the main feedwater pumps, the inspector inquired if any other signal was defeated. This inquiry was made to the acting operation superintendent at 0930 hours. At 1145 hours the "E" MDAFP was started and the "W" MDAFP was started at 1154 hours to maintain steam generator level. At approximately 1400 hours the acting operation superintendent informed the inspector that the neutral position also defeated the auto-start signal for low-low steam generator water level. Technical Specification Table 3.3-3 Item 6 requires all four (4) of the above auto-start signals to be operable in Mode 3.

c. Licensee Followup of the Event

Following the discussion concerning operability of the MDAFP with the switch positions existing at 0930 on August 8, 1984, Operations management checked out the logic diagrams for the switches and after some time decided that Technical Specifications must be satisfied with respect to the steam generator water level low-low automatic start signal. At this time the pumps were already running in automatic (after 1200 hours as water was needed in the steam generators) and the licensee decided to allow the auxiliary feed-water (AFW) pumps to be stopped by removing D.C. control power from one of the main feed pumps. This action defeated the AFW pumps auto-start feature on loss of both main feed pumps. At 1400 hours when they explained what conclusion they had reached and actions they had taken it was pointed out by the inspector that the auto start feature on loss of both main feed pumps was also required by the Technical Specifications in Mode 3. The licensee subsequently restored the operability of the start feature and notified all operators of the requirements for Auxiliary Feed Pump operability in Mode 3 - specifically that the control switch should be in AUTO or RUN at all times. The licensee is subsequently planning to pursue a design change which would allow stopping the pumps when not required for feeding while maintaining operability of the start features, or a change to the Technical Specifications, or both. A Condition Report was written to document the investigation into and corrective actions for this event. Licensee Event Report 315/84-16 was issued September 6, 1984 documenting the event and committing to provide a supplement describing corrective actions.

d. NRC Followup

After the inspector notified the licensee of the concern for operability of the auto-start features at 0930 on August 8, 1984, the licensee confidently responded that the start features were operable in all switch positions except Pull-to-Lock and Trip (spring returns out of this position), but that they would check plant logic drawings to be positive. Based on the assurances of two licensed and experienced Senior Reactor Operators no further investigation was conducted until later in the day. Interviews with operators indicated that the practice of stopping the MDAFP in the manner described above was based on two considerations. First, running the pump on recirculation heats up the condensate storage tank which is not considered advantageous from a pump performance standpoint. Second, the feed control valves had a history of leaking, and, at low steam generator pressures (just after entering Mode 3) when no water was needed, the steam generators would continue to fill. These concerns had never received adequate attention by management and required operation of the AFW system in a manner that some operators knew was not in literal compliance with the Technical Specifications.

An additional Technical Specification problem noted by the inspector was the misconception on the part of several licensed operators that the ESFAS instrumentation operability requirements were considered separate and distinct from the pump operability requirements in determining compliance with the Technical Specifications. The operators erroneously thought that the Technical Specification were met so long as the auto-start features for a pump could be considered operable, even though the feature had been defeated.

e. Safety Significance Assessment

The MDAFPs were capable of auto-start on a safety injection signal or a loss of voltage to the 4kv Bus. Low-low steam generator and loss of Main Feedwater Pumps start signals were defeated. On entering Mode 3 the two MDAFP were operable and steam generators were approximately 60% full. For plant conditions existing low in Mode 3 (temperature slightly above 350°F) there was little safety significance in defeating two of the start signals. The licensee, however, failed to recognize the violation (which continued to exist through a shift turnover of operators) and continued to heat up the primary system, thus increasing the significance of the violation.

The licensee's corrective action in restoring the switches to their proper positions was neither prompt, nor did their initial attempts at corrective action achieve compliance with the Technical Specifications.

4. Turbine Driven Auxiliary Feedwater Pump Inoperable

a. Background Information

D. C. Cook Technical Specification 3.7.1.2 for both Units 1 and 2 require one feedwater pump capable of being powered from an operable steam supply system to be operable in Modes 1, 2, and 3. Technical Specification 3.3.2.1 requires Engineered Safety Feature Actuation System instrumentation to be operable with response times as specified in Table 3.3-5 of the Technical Specifications. The table specifies that the response time for the Turbine Driven Auxiliary Feedwater Pump (TDAFP) be less than or equal to sixty seconds. Rated operating conditions for the TDAFP are 4350 rpm with a 900 gpm flow rate and discharge pressure of 1184 psig. Therefore, upon receipt of an automatic start signal, the TDAFP must be capable of reaching the above stated rated operating conditions in less than or equal to 60 seconds.

b. Event

During observation of 1-OHP-4030.STP.071 "Auxiliary Feedwater Pump Surveillance Test" on August 8, 1984, it was noted that on starting the TDAFP the discharge pressure came up to approximately 900 psig -- which was insufficient to inject water after a reactor trip (over 1,000 psig required). After completion of the test (which was satisfactory), it was noted that the turbine governor valve was positioned at 50% open according to the procedure. Subsequent testing, suggested by the inspector, confirmed that at the 50% valve position the required pump discharge pressure and flow would not have been achieved on an auto-start, but only after operator intervention. Following additional testing of the Unit 2 TDAFP on August 10, 1984 and Unit 1 TDAFP on August 11, 1984 the licensee set the governor valves at 90% open and 85% open respectively.

c. Licensee Followup of Event

Following the NRC interim exit meeting on August 10, 1984 the licensee performed testing which validated the inspectors' concerns. As corrective actions the governor valve positions were increased to 85% (Unit 1) and 90% (Unit 2) open to allow the TDAFP to auto-start and come up to rated speed. The licensee initiated an investigation into the basis of the 50% governor setting. It was found that a procedure revision dated August 8, 1978 instructed operators to set the speed of the turbine to obtain a discharge pressure approximately 50 psig higher than main feed pump discharge pressure. This setting roughly corresponds to the 50% governor setting. No reason was documented for the change.

On August 17, 1984 the inspector expressed concern over possible turbine overspeed trip or low suction pressure trip. On August 18, 1984 the licensee tested the TDAFP with the 85% and 90% governor settings and determined that operation was satisfactory. Analysis of testing on August 10, 11 and 18, 1984 was performed by the AEPSC/Columbus office and determined that the pumps were operable in the condition existing after the August 10 and 11, 1984 tests, but that prior to that time it did not appear that the pumps would have delivered 410 gpm at 1085 psig (lowest safety setpoint on steam generator) with no operator action. At 1336 hours on August 18, the NRC was notified of this preliminary determination via the ENS telephone network.

The licensee performed a safety evaluation of the situation and attached it to Licensee Event Report 315/84-19, submitted on September 17, 1984 (attached). In the evaluation, the licensee concluded that with limited operator action, the reduction in TDAFP flow did not adversely impact public health and safety.

d. Safety Significance Assessment

The condition of the governor valve position has apparently existed since August of 1978. Licensee procedures also exist which specifically require the operator to verify flow to the steam generators following an Emergency Core Cooling System actuation (OHP 4023.001.002 "Emergency Procedure Immediate Actions and Diagnostics"). Operators routinely adjust Auxiliary Feedwater flow following a reactor trip to minimize plant cooldown. Based on these factors and the licensee's safety evaluation, the inspector concluded that although auxiliary feedwater capability was degraded, the safety function would have been preserved through reasonable operator action.

5. Enforcement Conference

On September 7, 1984, an Enforcement Conference was held at the NRC regional office to discuss the three situations of inoperable safeguards equipment (MDAFP, TDAFP, ESF FANS). Licensee representatives in attendance are denoted in Paragraph 1. The NRC outlined the three events which indicated a lack of knowledge and understanding by site personnel in the areas of Technical Specifications and operability requirements. Operator knowledge of operating requirements for safety systems and recent Operator Requalification Exam results were also discussed.

The licensee responded to each issue as summarized below: The ESF fan inoperability for a period of about 12 hours is viewed as being only administratively inoperable, not functionally inoperable. It was also mentioned that safety analysis criteria would allow operator restart 10 minutes after a demand signal. [The Normal Operating Procedure for the ESF Ventilation System describes the auto-start function, but there is no reason to believe that an operator would use that procedure during an event. The Phase A Containment Isolation Abnormal Operating Procedure did not require verification of fan start.]

The MDAFP inoperability is considered to be of relatively small significance since the Standard Technical Specifications allow the automatic start on loss of main feed pumps to be defeated. Also, the operators were controlling steam generator levels manually and would be expected to start the pumps before the low-low level alarm was reached.

The TDAFP governor setting at 50% was analyzed for the accidents where credit was taken for the pump in mitigating the consequences of the accident. Both cooldown and heatup transients were analyzed as previously discussed in Paragraph 4.C above.

Concerning Operator Requalification Training, the licensee provided statistics of overall exam results which supported their conclusion that there is no need to make major changes in the requalification programs.

Corrective actions related to prevention of the events of concern which were not previously discussed in paragraph 4 were also discussed.

- Engineering review of procedures to assure Technical Specification compliance with priority placed on containment integrity, Auxiliary Feedwater, and ECC Systems. Approximately 50 target procedures are to be reviewed in two months.

- Independent corporate review of plant operations to ensure adherence to procedures and consistency of procedures in implementing the Technical Specifications. Program is to include personnel from the corporate Nuclear Safety and Licensing and Nuclear Fuel Management staffs functioning as the licensee's own resident inspectors. Dedicated assignments to verify the basis and reason for each step of a procedure will be made.

- Additional training is to be provided to Shift Technical Advisors as to the basis of safety analysis. Part of this training will include individuals being detailed to work in the Nuclear Safety and Licensing group for cross-training.

- Technical Specifications to be reviewed and revised to allow literal compliance with them.

- Operator training on the practical aspects of system design and relationship to the Technical Specifications.

At the conclusion of the conference, the licensee agreed that the events fit the Category III description of the Enforcement Policy. The NRC asked to be provided additional details of their corrective actions.

AMERICAN ELECTRIC POWER SERVICE CORPORATION

AEP

AMERICAN ELECTRIC POWER SYSTEM

DATE: September 13, 1984

SUBJECT: DONALD C. COOK NUCLEAR PLANT UNIT NOS. 1 AND 2
SAFETY EVALUATION FOR REDUCED TURBINE DRIVEN AUXILIARY
FEEDWATER PUMP FLOW

FROM: D. A. Medek

TO: W. G. Smith, Jr. - Bridgman

While performing an audit of the Donald C. Cook Nuclear Plant In-Service Testing (IST) Program, the NRC questioned the ability of the Turbine Driven Auxiliary Feedwater Pump (TDAFP) to fulfill its design functions with the associated governor valve set to 50%. This letter provides the AEPSC Nuclear Safety & Licensing Section's (NS&L's) review findings with regard to this issue.

As explained herein, the effective reduction in TDAFP flow is believed to be enveloped by the D. C. Cook Plant licensing basis safety analyses for three postulated events, i.e., steam line break, loss of normal feedwater, and station blackout. Additionally, although the reduced TDAFP flow is not enveloped by the D. C. Cook Plant main feedwater line break licensing basis safety analysis, it is believed that with limited operator actions the response of the D. C. Cook Plant during this postulated event would be bounded by the Tennessee Valley Authority's (TVA's) Sequoyah Nuclear Plant Final Safety Analysis Report (FSAR). Based on these findings it is believed that setting the governor valve to 50%, with the attendant reduction in deliverable flow from the TDAFP to the steam generators, did not adversely impact public health and safety.

The details of the review findings follow:

Steam Line Break

The break of a steam line results in a sharp reduction in steam generator steam inventory. The secondary side pressure decrease which accompanies this loss of inventory gives rise to an energy demand which in turn reduces Reactor Coolant System (RCS) temperature and pressure. With a negative moderator temperature coefficient, the reduction in RCS temperature and pressure causes a reactivity insertion which could lead to criticality and core damage under pessimistic circumstances.

Steam line break analyses for the D. C. Cook Plant Unit 1 are presented in Section 14.2.5 and Appendix C to Chapter 14 of the Updated FSAR; similar analyses for Unit 2 are presented in Section 14.2.5 and Appendices B and C to Chapter 14 of the Updated FSAR. These analyses indicate that for even large breaks with rapid emptying of the pressurizer, the minimum capability for injection of high concentration boric acid (corresponding to the most restrictive single failure in the centrifugal charging system) is adequate to control the return to power and to ultimately shut down the reactor.

For the steam line break accident, maximum delivery of auxiliary feedwater flow is conservative because it would effectively maximize the RCS cooldown and the subsequent return to power. Therefore, setting the governor to 50%, with the resultant reduction in TDAFP flow delivery to the steam generators, should not adversely affect the results of the existing analyses.

Loss of Normal Feedwater/Station Blackout

Loss of normal feedwater analyses for the D. C. Cook Plant are presented in Section 14.1.9 and Appendix C to Chapter 14 of the Updated FSAR (Unit 1 and Unit 2); station blackout analyses are presented in Section 14.1.12 and Appendix C to Chapter 14 of the Updated FSAR (Unit 1 and Unit 2).

The postulated loss of normal feedwater (due to pump failures, valve malfunctions, etc.), and the loss of all AC power to the station auxiliaries, may result in reduced secondary side capability to remove the heat generated from the reactor core. For the loss of normal feedwater event, an alternative supply of feedwater must be supplied to the unit before the core residual heat leads to primary system water relief from the pressurizer. For the case of station blackout, natural circulation flow in the RCS following RCP coastdown, in conjunction with auxiliary feedwater supply to the steam generators, provides sufficient heat removal capability to preclude core damage.

The existing Updated FSAR analyses for these events indicate that the auxiliary feedwater flow delivered to two steam generators by one Motor Driven Auxiliary Feedwater Pump (MDAFP) is sufficient to provide the required heat removal capability. Therefore, since no credit has been taken in the analyses for the TDAFP flow, setting the governor valve to 50% should have no effect on the analyses.

Feedwater Line Break

The postulated feedwater line break event is not a part of the D. C. Cook Plant Unit 1 design basis, but has been analyzed for Unit 2 with a minimum auxiliary feedwater flow rate assumption. The Unit 2 analysis is presented in Section 14.2.8 of the Updated FSAR.

NS&L has been advised by Westinghouse Electric Corporation (W) that the current assumptions include a single failure assumption of one MDAFP, leaving the other MDAFP and the TDAFP to provide auxiliary feedwater flow to the steam generators. Therefore, setting the governor valve to 50% would reduce the auxiliary feedwater flow rate below that which is assumed in the FSAR.

W has noted, however, that other nuclear facilities of similar design and licensed in the same time frame as the D. C. Cook Plant, i.e., Sequoyah Nuclear Plant and Salem Nuclear Plant, assume that no auxiliary feedwater flow is delivered to the intact steam generators prior to operator action at ten minutes. At that time, the operator would be expected to isolate auxiliary feedwater to the faulted steam generator and to ensure that auxiliary feedwater was being delivered to the intact steam generators. With an assumption of ten minutes operator action time to restore the TDAFP governor, W believes that the feedwater line break would be bounded by the results provided in the Sequoyah Nuclear Plant FSAR. Therefore, the consequences presented in the FSAR would remain valid.

W has also noted that the evaluation for Unit 2 is also applicable to Unit 1, although the feedwater line break is not a part of the Unit 1 licensing basis. The only difference noted by W is that the required operator actions would include isolation of the faulted steam generator from the intact steam generators. This would be required for Unit 1 since the steam line isolation logic requires a high steam flow signal coincident with the low steam pressure signal. Steam line isolation is needed to assure a sufficient steam supply pressure to the TDAFP in order to maintain its function.

Based on the above it is believed that setting the governor valve to 50%, with the attendant reduction in deliverable flow from the TDAFP to the steam generators, did not adversely impact public health and safety.

David A. Medek

David A. Medek

Approved: James G. Feinstein

J. G. Feinstein, Manager
Nuclear Safety & Licensing Section

DAM/th

cc: M. P. Alexich
S. H. Steinhart
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