D O N A L D C. C O O K N U C L E A R P L A N T

ANNUAL OPERATING REPORT

1981

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INTRODUCTION

The D. C. Cook Nuclear Plant, owned by the Indiana & Michigan Electric Company and located five miles North of Bridgman, Michigan consists of two 1100 MWe pressurized water reactors. The nuclear steam supply systems for both units are supplied by Westinghouse with a General Electric turbine-generator on Unit 1 and a Brown-Boveri turbine-generator on Unit 2. The condenser cooling method is open cycle, using Lake Michigan water as the condenser cooling source. The D. C. Cook Nuclear Plant was the first nuclear facility to use the ice condenser reactor containment system, which utilizes a heat sink of borated ice in a cold storage compartment located inside the containment. The architect/engineer and constructor was the American Electric Power Service Corporation.

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D. C. Palmer	-	Personnel Exposure Summary
H. H. Bolinger	-	Inservice Inspection
E. A. Abshagen	-	Changes to Facility

PERSONNEL EXPOSURE SUMMARY

The following table represents a tabulation on an annual basis of the number of plant, utility and other personnel receiving exposure greater than 100 mRem/year and their associated man-rem exposure according to work and job functions. The data included in this table is developed primarily from self-reading dosimeter results.

Assignment of personnel to various groupings is based on what type of work they are usually involved with. Specifically, assignments are made as follows:

Maintenance Personnel -- Includes non-exempt (non-supervisory) personnel from the Maintenance Department and from the Control & Instrument Section of the Technical Department

Operating Personnel -- Includes non-exempt personnel from the Operations Department, from the Chemical Section of the Technical Department, from the Quality Assurance Department and Security Personnel

Health Physics Personnel -- Includes non-exempt personnel from the Radiation Protection Section of the Technical Department

Supervisory Personnel -- Includes exempt (supervisory) personnel from all departments who function primarily as supervisors of non-exempt personnel

Engineering Personnel -- Includes personnel not primarily functioning as supervisors of non-exempt personnel. This includes such personnel as maintenance engineers, nuclear engineers, performance engineers and station management.

REPORT OF NUMBER OF PERSONNEL AND MAN-REM BY WORK AND JOB FUNCTION
1981

WORK AND JOB FUNCTION	NUMBER OF PERSONNEL (>100 mRem)			TOTAL MAN-REM		
	STATION EMPLOYEES	UTILITY EMPLOYEES	CONTRACT WORKERS AND OTHERS	STATION EMPLOYEES	UTILITY EMPLOYEES	CONTRACT WORKERS AND OTHERS
REACTOR OPERATIONS & SURVEILLANCE						
Maintenance Personnel	84	0	35	3.830	0	1.855
Operations Personnel	69	0	2	28.385	0	.150
Health Physics Personnel	17	0	29	2.630	0	4.437
Supervisory Personnel	17	2	4	1.950	.430	.330
Engineering Personnel	9	0	1	.500	0	.040
ROUTINE MAINTENANCE						
Maintenance Personnel	117	0	192	85.680	0	33.433
Operations Personnel	29	0	7	1.380	0	.942
Health Physics Personnel	17	0	31	2.470	0	6.974
Supervisory Personnel	11	1	11	2.580	.140	2.150
Engineering Personnel	7	0	2	.470	0	.060
INSERVICE INSPECTION						
Maintenance Personnel	78	0	110	16.360	0	15.828
Operations Personnel	9	0	11	1.140	0	3.648
Health Physics Personnel	7	0	27	.630	0	6.840
Supervisory Personnel	11	0	6	.990	0	.390
Engineering Personnel	10	0	12	1.170	0	2.990
SPECIAL MAINTENANCE						
Maintenance Personnel	82	1	425	15.080	.140	207.965
Operations Personnel	8	0	19	.360	0	8.380
Health Physics Personnel	11	0	34	.840	0	7.642
Supervisory Personnel	9	5	24	1.650	3.980	11.182
Engineering Personnel	9	1	3	.300	.200	.210
WASTE PROCESSING						
Maintenance Personnel	50	0	142	8.140	0	36.321
Operations Personnel	26	0	10	1.390	0	8.244
Health Physics Personnel	14	0	24	2.770	0	1.680
Supervisory Personnel	4	0	6	.550	0	1.760
Engineering Personnel	3	0	1	3.130	0	.100
REFUELING						
Maintenance Personnel	59	0	92	5.380	0	39.577
Operations Personnel	12	0	2	.770	0	.410
Health Physics Personnel	2	0	23	.050	0	3.120
Supervisory Personnel	6	0	7	.700	0	1.090
Engineering Personnel	2	0	2	.220	0	.340
TOTAL						
MAINTENANCE PERSONNEL	117	1	541	134.470	.140	334.979
OPERATIONS PERSONNEL	69	0	31	33.425	0	21.774
HEALTH PHYSICS PERSONNEL	18	0	36	9.390	0	30.693
SUPERVISORY PERSONNEL	20	5	27	8.420	4.550	16.902
ENGINEERING PERSONNEL	16	1	15	5.790	.200	3.740
GRAND TOTAL	240	7	650	191.495	4.890	408.088

1981 ANNUAL INSERVICE INSPECTION REPORT OF STEAM GENERATORS

During the March/April, 1981, Unit 2 Refueling Outage a required examination of predetermined tubes in Steam Generators 2-1 and 2-4 was performed by Westinghouse Nuclear Service Division using a Multi-Frequency Eddy Current testing technique. The tube selection included at least 6% of all tubes in each of the two steam generators as required by Regulatory Guide 1.83 entitled Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes and the Donald C. Cook Nuclear Plant Unit 2 Technical Specifications, Sections 4.4.5.2 and 4.4.5.3. The examination data was evaluated by a Zetec, Inc., interpreter certified to Level IIA using Zetec equipment calibrated in accordance with Zetec procedures and in conformance with acceptance criteria specified in Regulatory Guide 1.83 and Technical Specification Section 4.4.5.4.

No tube plugging was deemed necessary based on these eddy current test findings but based on findings of a previous year which revealed that the tube lane blocking device had oscillated abrading five tubes which were plugged at that time, AEPSC and Plant Management elected to plug the remaining four tubes adjacent to the tube lane blocking device in Steam Generator 2-1 and to plug all ten tubes adjacent to the tube lane blocking device in Steam Generator 2-4. The plugging was accomplished using "mechanical plugs" furnished by Westinghouse Corporation and was completed by Westinghouse personnel using Westinghouse procedures approved for this activity.

The extent and results of this examination are summarized as follows:

STEAM GENERATOR 2-1

1) Examined 368 tubes through the U-bend.

2) Examined 25 tubes full length.

3) Examined 20 tubes through the top support.

4) Examined 380 tubes through the first support.

5) This examination revealed no tubing degradation having an imperfection greater than 20% of the wall thickness.

6) Tubes designated Row 1 Column 90, Row 1 Column 91, Row 1 Column 92 and Row 1 Column 94 were plugged.

7) All testing was performed from the hot leg side.

STEAM GENERATOR 2-4

1) Examined 284 tubes through the U-bend.

2) Examined 25 tubes full length.

3) Examined 20 tubes through the top support.

4) Examined 380 tubes through the first support.

5) This examination revealed no tubing degradation having an imperfection greater than 20% of wall thickness.

6) Tubes designated Row 1 Column 1, Row 1 Column 2, Row 1 Column 3, Row 1 Column 4, Row 1 Column 5, Row 1 Column 90, Row 1 Column 91, Row 1 Column 92, Row 1 Column 93 and Row 1 Column 94 were plugged.

7) All testing was performed from the hot leg side.

During the June/July 1981 Unit 1 Refueling Outage, Westinghouse Corporation Nuclear Service Division conducted an eddy current examination of a predetermined sample of tubes in Steam Generators 1-1 and 1-4 utilizing a multi-frequency technique. The tube selection included at least 6% of all tubes in each of the two Steam Generators as required by Regulatory Guide 1.83 entitled Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes and Donald C. Cook Nuclear Plant Technical Specifications 4.4.5.2 and 4.4.5.3. The examination data was evaluated by a Zetec, Inc., interpreter certified to Level IIA using Zetec equipment calibrated in accordance with Zetec procedures and in conformance with the acceptance criteria specified in Regulatory Guide 1.83 and Technical Specification Section 4.4.5.4.

The extent and results of this informational inspection were as follows:

STEAM GENERATOR 1-1

1) Examined 277 tubes through the U-bend.

2) Examined 24 tubes full length.

3) Examined 380 tubes through the first support.

4) Examined 20 tubes through the seventh support.

5) The examination revealed no tubing degradation having a penetration greater than 20% of the wall thickness.

6) No tubes were plugged.

7) All testing was performed from the hot leg side.

STEAM GENERATOR 1-4

1) Examined 270 tubes through the U-bend.

2) Examined 26 tubes full length.

3) Examined 380 tubes through the first support.

4) Examined 20 tubes through the seventh support.

5) The examination revealed no tubing degradation having a penetration greater than 20% of the wal' thickness.

6) No tubes were plugged.

7) All testing was performed from the hot leg side.

In October 1981, in the wake of a trend analysis which disclosed that the primary-to-secondary side leakage in Steam Generator 2-1 was steadily increasing, Unit 2 was removed from service in order that appropriate water pressure and eddy current testing could be conducted to determine the point of the leakage. It should be noted, however, that even though an appreciable amount of leakage was being calculated - 0.292 gpm maximum - it did not equal the Donald C. Cook Nuclear Plant Technical Specification (3.4.6.2c) maximum allowable primary-to-secondary leakage through one steam generator - 500 gallons per day or 0.347 gpm.

St am Generator 2-1 was drained and the primary side dried out. The secondary side was filled with water and pressure was applied using nitrogen as the pressure generative source. A remote camera was placed in position at both the hot and cold leg sides so that the tube openings could be continuously scanned for leaks as pressure was applied. In conjunction with the remote scanning, a visual inspection was periodically performed. At 260 psig, water was visually observed dripping from tubes designated Row 1 Column 78 and Row 1 Column 79. The pressure was bled off and Westinghouse Corporation was directed to probe the 24 tubes comprising a 3 x 8 grid around the two leaky tubes using a multi-frequency eddy current testing technique. The eddy current test results were evaluated by a Zetec interpreter certified to Level IIA using Zetec equipment calibrated in accordance with Zetec procedures and in conformance to the inspection criteria specified in Regulatory Guide 1.83 and the Donald C. Cook Nuclear Plant Technical Specifications. No indications were found in the tubes probed except the tube designated Row 1 Column 78. The Zetec interpreter reasoned that the defect in the tube designated Row 1 Column 79 was evidently a circumferential defect, which, due to the acuteness of the angle of the bend of Row 1 tubes, was not being picked up by the eddy current test technique.

Steam Generator 2-1 was again refilled with water on the secondary side and, using nitrogen, pressure was gradually increased to 660 pounds psig. The hot and cold leg sides were then scanned simultaneously for two hours. No other leakers were found. However, it was noted that the additional pressure opened up the defects in Row 1, tubes 78 and 79, as the leakage rate increased substantially.

The pressure was again vented and Westinghouse was directed to probe all of the Row 1 tubes. Upon completion, the Zetec interpreter evaluated the test data and noted a slight wrinkle in the trace on the CRT for the tube designated Row 1 Column 74. He stated that the angles could not be measured but that it was an indication of some kind of flaw and recommended plugging the tube. Again, no indication could be seen in the new data acquired for tube designated Row 1 Column 79.

A total of 100 tubes were tested using a multi-frequency eddy current testing technique probing from the cold leg side over the U-bend. The indication and defects were determined to be in the U-bend.

Tubes designated Row 1 Column 74, Row 1 Column 78 and Row 1 Column 79 were plugged on October 10, 1981.

CHANGES TO FACILITY

Brief descriptions and summary safety evaluations for design changes (RFC's) made to the facility as described in the Donald C. Cook Nuclear Plant Final Safety Analysis Report (FSAR) are presented in this section. These changes were completed pursuant to the provisions of Title 10, Code of Federal Regulations subsection 50.59(a).

DC-01-1832

The Steam Generator level protection set low-low bistables of Unit #1 of the D. C. Cook Nuclear Plant were recalibrated for actuation at 17% (decreasing mode) of narrow range level span. The previous set-point was 15% of level decreasing. The Steam Generator Level low-low bistable outputs serve actuation signals for a reactor trip, motor driven auxiliary feedwater pump start and turbine driven auxiliary feed-water pump start. The Steam Generator Level low bistable setpoints will remain at their present values and are not affected by this Design Change.

This change was needed to conform with Amendment #43 to the Unit #1 Technical Specifications.

By letter dated 22 June 1979 (NS-TMA-2104) Westinghouse (W) submitted to the Commission a 10 CFR Part 21 defect/non-compliance report which discussed the potential for non-conservative level bias following a postulated high energy line break (HELB) inside containment. The NRC subsequently issued IE Bulletin No. 79-21 addressing this potential safety concern. Our responses to the Bulletin, as well as a discussion of the applicability of the W 10 CFR 21 Report to the Cook Plant is contained in our AEP:NRC:00271, AEP:NRC:00271B, and AEP:NRC:00271C submittals.

The "Steam Generator Low-Low Level" reactor trip and Engineered Safety Feature Actuation System Setpoints were revised previously under RFC DC-12-2406 (reported in 1979 Annual Operating Report) to include a 4% (of narrow range instrument span) allowance for reference leg heatup following a HELB inside containment. During subsequent telephone discussions with the NRC staff and their consultants we were required to apply an additional 2% allowance to the Unit No. 1 setpoint to account for zero span calibration errors. It is this additional 2% allowance which has led to recalibration of the protection set low-low bistables under RFC DC-01-1832. (Note: The Unit No. 2 setpoint, 21%, already includes such an allowance.)

Implementation of this RFC does not constitute an unreviewed safety question as defined in 10CFR50.59 and will not endanger the health and safety of the general public.

DC-02-1848 (Unit #2)
DC-01-1849 (Unit #1)

The Pressurizer Safety Valve loop seal drain lines and the common drain header at its connection to the 12" pressurizer relief tank (PRT) drain line were cut and capped on both units of the D. C. Cook Nuclear Plant. The three Seismic Class I loop seal drain valves (RC-127, -128 and -129); the valve at the connection to the PRT drain line (RC-130) and associated piping were removed. This design change was necessary to eliminate excessive leakage through these unnecessary valves which has caused delays in plant startup.

The effects on the safety analysis, seismic analysis and piping corrosion were the major areas of the review. The FSAR and System Descriptions were reviewed and no safety analysis assumptions related to these drain lines were found. The FSAR does contain a figure (4.2-1A) which shows this line but a review of the NRC's Safety Evaluation Report for Cook indicates that there was no mention of the drain lines in concluding that the RCS is acceptable. In the area of seismic concerns, the ½" drain lines provide drainage of the 6" loop seal lines and the piping is Seismic Class I until downstream of the drain valves where it becomes Seismic Class II. After discussing the matter with Mechanical Engineering Division personnel and other Nuclear Safety and Licensing engineers, we believe that the removal of the ½" drain line will not adversely affect the seismic analysis/qualification of the loop seals or the 12" PRT drain line. Given the size of the line and its location and supporting that there should not be any potential missile concerns even if the line itself is not physically removed.

The corrosion concerns arise from the presence of stagnant borated water in the loop seal (see IE Circular 76-06 and IE Bulletin 79-17). The loop seal is not drained as a matter of course during refueling operations. On occasion these valves have been used to drain the loop seals in order to aid in other maintenance and inspection activities. Since the welds of the loop seals are already incorporated into the ISI program, the corrosion concerns have been adequately addressed. Future drainage of the loop seals, if necessary, will have to be accomplished in a different manner.

RFC DC-02-1848 (DC-01-1849) does not create a substantial safety hazard nor does it constitute an unreviewed safety question as defined in 10CFR50.59.

DC-12-1868

This design change modified the action/reset portion of the Reactor Coolant Pump Fire Suppression System logic. The modifications included the addition of an air/water bypass valve on each Reactor Coolant Pump and two air accumulator tanks.

Originally, solenoid valves were used to actuate the system by directly releasing water from the Viking Flow Control Valve. The solenoid valves were found to be plugging up due to sediment in the water. The RFC alleviated this problem by using the solenoid valves to release air from the top of a diaphragm valve which provides an air/water interface. The diaphragm valve in turn releases the water from the flow control valve.

This RFC changes the actuation/reset portion of the Reactor Coolant Pump (RCP) fire suppression system logic for ease of performing Technical Specification surveillance requirements. The equipment being modified, while under the scope of the fire protection QA program, is not safety related and is Seismic Class III. The fire suppression system, when tested in accordance with the Technical Specifications, successfully actuated. However, since the reset portion of the actuating logic did not properly function, the full Technical Specification operability requirements could not be met. The reset portion of the system is not necessary for actuating the water suppression capability to mitigate a design basis fire involving the RCP's but is a necessary part of the system to comply with the operability requirements. As such, this RFC is considered to be safety interface.

RFC DC-12-1868 does not create a substantial safety hazard nor does it constitute an unreviewed safety question as defined in 10CFR50.59.

DC-12-2039

This design change provided the capability for both Units' Diesel Generators to share the resistive load banks for surveillance testing purposes. The modifications allow for interruption of testing and assumption of essential loads under accident or blackout conditions. This design change also added negative sequence relays on both load banks to protect the Diesel Generators from damage due to load bank failure and single phasing or phase unbalance when the Diesel Generator is connected to the Load Bank. The control scheme has several electrical interlocks to prevent inadvertently connecting both Units' Diesels to the load bank simultaneously. In addition, mechanical interlocks have been added to the Diesels by placing key operated locks on the test breakers. One key is provided for each train, in order to rack in the test breaker the key must be used to unlock the mechanism. The key cannot by removed until the breaker is racked back out, preventing both test breakers from being racked in simultaneously.

Originally, two GE type NGV undervoltage relays per diesel existed in the undervolatage monitoring circuit. These relays monitored via PT's, the voltage on the 4KV ESS buses, one relay monitors voltage between phases 1-2 and the other between phases 2-3. Had the voltage dropped below the relay setpoints on both of these relays, the NGV relays would de-energize and automatically start the diesel engine via additional relay logic. Both relays had to be de-energized to cause an engine start.

This diesel change added an NGV relay to monitor voltage between phases 1 and 3, thereby revising the monitoring circuit so that there are now 3 NGV relays per diesel. The output contacts of these relays are connected in such a way that the de-energization of any 2 of the 3 NGV relays will now cause a diesel start.

The changes indicated in this RFC will reduce the need to parallel the Diesel Generators to a live plant bus for testing purposes and improve the reliability of the on-site power supply. The subject changes do not prevent the system from performing its intended safety function and do not constitute an unreviewed safety question as defined in 10CFR50.59.

DC-12-2435 (Unit #2 Only)

Thermal sleeves were installed at the junction of the 16" diameter elbows and the Steam Generator nozzles in the Feedwater System on Unit #2 of the Donald C. Cook Nuclear Plant. The thermal sleeves were installed to minimize thermal stresses in the elbows.

The feedwater line thermal sleeve modification extends from the vertical pipe reducer through the elbow and into the steam generator nozzle. The nozzle end of the thermal sleeve contains two piston rings (contained in one groove) to seal the annular gap. This promotes a low convective heat transfer coefficient which is beneficial in reducing thermal stresses at the nozzle and pipe inside surfaces.

The nozzle thermal sleeve is 0.38" thick and fabricated from SA-106-GR B. The new thermal sleeve is 0.50" thick and also fabricated from SA-106-GR B. carbon steel. An inconel 600 weld build-up is placed on the pipe reducer to accomodate welding of the new sleeve. This feature provides an improvement in fatigue strength over that of an equivalent carbon steel section.

This change is considered to be safety-related due to the fact that the affected portion of the main feedwater piping, the steam generators, and the thermal sleeves themselves are Seismic Category I components.

Nuclear Safety and Licensing has continuously been involved in the efforts regarding the feedwater elbow cracking problem, the subsequent correspondence between AEP and the NRC, and with regards to the corrective actions taken. Based on the information contained in Attachment No. 2 to our AEP:NRC:00305 submittal and completion of an acceptable seismic analysis, it has been concluded that implementation of this RFC does not constitute an unreviewed safety question as defined in 10CFR50.59 and will, in fact, increase the already high level of safety of the Cook Plant.

DC-12-2447

The existing control grade differential pressure transmitters FFI-210, -220, -230 and -240 at the Donald C. Cook Nuclear Plant were replaced with qualifified N-E13DM Electronic d/p cell transmitters manufactured by The Foxboro Company. These transmitters are used for Auxiliary Feedwater flow indication to Steam Generator loops #1, 2, 3 and 4 respectively. The transmitters were replaced in accordance with the requirements of NUREG-0578 and NUREG-0737.

DC-12-2447 calls for the installation of environmentally qualified (outside containment) Auxiliary Feedwater System flowrate transmitters to achieve full compliance with Part 2 of item II.E.1.2 of NUREG-0737. The requirements for a safety-grade Auxiliary Feedwater System flow indication to each Steam Generator as originally stated in item 2.1.7.b of NUREG-0578, and as clarified by NRC letter from H. R. Denton dated October 30, 1979, have been changed and superceded by the requirements of NUREG-0737. The requirements applicable to the D. C. Cook Plant have been relaxed to require only a single-channel flow indication, instead of redundant class 1E channels. For plants with U-tube steam generators, like the D. C. Cook Plant, Auxiliary Feedwater System flow indication is of secondary importance in assuring Steam Generator cooling capability. This design change is safety related because the Auxiliary Feedwater System is Seismic Class I and is required to function during many design basis accidents and transients. This design change is necessary to provide added assurance that there is adequate capability in the control room to ascertain the actual performance of the Auxiliary Feedwater System when it is called on to perform its intended safety function.

The Nuclear Safety and Licensing Section has reviewed this design change in light of our responses to NUREG-0578 and NUREG-0737 and finds that the scope of work covered by this design change is consistent with both the NRC requirements and our commitments thereto. In accordance with our response to item II.E.1.2 in our letter No. AEP:NRC:00398 it is required that this work be completed in both Units 1 and 2 by July 1, 1981.

The required Technical Specification changes have already been submitted to the NRC by our letter No. AEP:NRC:00449 and incorporate the Auxiliary Feedwater System flow indication function with the Steam Generator narrow range water level indication for meeting the NRC redundancy requirement. The Steam Generator wide range water level indication mentioned in NUREG-0737 is included in the proposed Technical Specification to serve only as a backup to the Auxiliary Feedwater System flow indication channel in the event the latter becomes inoperable. The Technical Specifications were issued in Amendment #49 for Unit #1 and in Amendment #34 for Unit #2.

DC-12-2447 does not create a substantial safety hazard nor does it constitute an unreviewed safety question as defined in 10CFR50.59.

DC-12-2451

This design change provides redundant and continuous Control Room monitoring of containment water level and containment sump water level of each unit of the D. C. Cook Nuclear Plant. The installation was performed in conformance to the requirements of NUREG-0578 as revised by NUREG-0737.

Two independent narrow range level indication channels (NLI-311 and NLA-310 were installed in each unit to measure lower containment sump water level. These channels extend from the bottom of the sump at an elevation of 589'8" to the top of the sump at an elevation of 599'8". Included in the NLA-310 channel is a low level alarm and a high level alarm which are set at an elevation of 590'4" and 598' respectively.

Two independent wide range level indication channels (NLI-320 and NLI-321) were installed in each unit to measure lower containment water level. These channels extend from the lower containment floor at an elevation of 399'3" to an elevation of 614'0". This level is equivalent to 600,000 gallons of water.

The addition of the above indications removed the requirement for the recirculation sump level indicating lights (ILI-100 through ILI-105) and associated equipment which has been removed. The displays for the new level indication channels are mounted on the RHR panel in the Control Room in place of the recirculation sump level indicating lights.

The subject RFC is considered to be safety related because the new instrumentation systems are to be procured and installed as safety grade equipment for accident monitoring use. As such the system (all equipment involved) must meet all appropriate requirements for Class 1E systems such as:

a) Environmental qualification,
b) Seismic qualification,
c) Physical separation requirements (per Regulatory Guide 1.75),
d) Emergency bus power supplies,
e) Train orientation of the equipment,
f) Protection from high energy line breaks (pipe whip, jet impingement, etc.) and missiles,
g) Testability provisions.

This RFC also incorporates the existing sump water level alarms into the new system and as such the interfacing with these alarms must now be treated as ESF equipment (formerly Balance of Plant). An overlap of 5 inches is provided between the narrow and the wide range monitors. All transmitters are to be installed on the outer side of the crane wall. In this design change, safety grade isolation devices will be used as an interface between the safety-grade portion and the display portion of the system where the latter is of Balance of Plant design. Such an arrangement complies with provision made for Class 1E redundant systems in which physical separation of power source is demanded up to and including the isolation device.

On May 23, 1980 the NRC issued a "Memorandum and Order" concerning environmental qualification of safety-related electrical equipment. The requirements of this order as applied to the subject design change (which calls for purchasing new equipment) means environmental qualification must be in accordance with the provisions of IEEE-323-1974. Clearly the IEEE-323-1974 requirement applies not only to the transmitters but to any other new equipment purchased for this design change.

This safety review is conducted on the design change compliance to NUREG-0737 and concludes that the proposed changes do not create a substantial safety hazard nor involve an unreviewed safety question as defined by 10CFR50.59.

DC-12-2452

A redundant level indication channel was installed on each unit's Condensate Storage Tank. These changes were necessary to comply with the "Additional Short Term Recommendation No. 1" of the post-TMI requirements for the Auxiliary Feedwater System in the NRC's October 30, 1979 letter. The new electronic level monitoring channel consists of a differential pressure transmitter connected to the Condensate Storage Tank drain line through its own sensing line with its output signal connected to a 0-100% level meter. This system is redundant to the existing Condensate Storage Tank level monitoring system in accordance with the NRC requirement. The piping connection at the Condensate Storage Tank drain line is Seismic Class II, consistent with Condensate Storage Tank classification and is Class III beyond this connection. This level monitoring channel is not safety grade equipment.

Since the Condensate Storage Tank inventory is necessary for the automatic actuation of the Auxiliary Feedwater System (as its primary water source) and that some Seismic Class II equipment is affected by this method of monitoring that inventory, this design change is considered to be safety interface. Although this design change is safety interface, the entire Condensate Storage Tank level monitoring system (new and existing) is Balance of Plant equipment.

The new level monitor has its power derived from the vital instrument buses (CRID II, circuit 4) with appropriate isolating devices at the Class 1E/Balance of Plant interface. The sensing line to the new differential pressure transmitter is heat traced for freeze protection. The heat tracing circuit derives its power from a Balance of Plant source (600V bus 11BMC and MCC 1AB-B) and is load shed. This is consistent with the requirements for Balance of Plant equipment. The Seismic Class II/Class III sensing line interface at the Condensate Storage Tank does not require any new seismic analysis to be performed.

The Nuclear Safety and Licensing (NS&L) Section has also reviewed this design change in light of our commitments made in response to the NRC in AEP:NRC:00300, 00307C and 00307D and their June 1, 1981 Safety Evaluation Report. This review shows that this design change fulfills those commitments in an acceptable manner. As such, the Nuclear Safety and Licensing section has no reason to object to the changes being implemented under the subject design change.

RFC DC-12-2452 does not create a substantial safety hazard nor does it constitute an unreviewed safety question as defined in 10CFR50.59.

DC-12-2460

Three seismically and environmentally tested mercoid pressure switches were installed in parallel with one another in each Auxiliary Feedwater Pump Suction piping circuit. Thus there is a total of 18 mercoid snap action type pressure switches with their associated piping, electrical wiring, and electrical relays. The trip circuitry for each pump is totally independent of any other pump's mercoid pressure switch low suction pressure trip circuit.

Each mercoid is calibrated and wired such that a pressure $\leq$ 3.84 PSIG will close the contacts to energize a HFA relay, and give an alarm/annunciation in the Control Room. If only one mercoid of the three per pump operates due to low suction pressure, there is no trip function for that pump, only an alarm/annunciation in the Control Room.

The circuit wiring is of a 2 out of 3 logic for the associated breaker (or Turbine trip & throttle valve for the Turbine Driven Auxiliary Feedpump) to trip. A combination of any two (or all 3) mercoid pressure switches being activated by low suction header pressure will trip open the associated breaker for that pump. For the Auxiliary Feedwater pumps, the solenoid would de-energize and the trip and throttle valve would trip closed on the 2 out of 3 logic.

There is also an agastat time delay of > 5 seconds (nominal 5.5 seconds) after the 2 (or 3) of 3 logic energizes the agastat coil before the trip circuit resumes operation. This change was made to further ensure that the Auxiliary Feedpumps are not tripped due to spurious or short transitory pressure surges such as during pump starts. Thus there will be no pump circuit breaker or trip and throttle valve trips unless the inadequate suction pressure on 2 of 3 (or 3 of 3) Mercoid Pressure Switches remains below 3.84 PSIG for more than 5 seconds. If adequate suction pressure is restored to 2 (or 3) of the 3 Mercoid Switches before the 5 second time delay lapses, the trip circuit is automatically reset and there will be no trip. However, if suction pressure falls below 3.84 PSIG for any length of time, the annunciator will alarm and must be reset.

This RFC is considered to be safety related because the Auxiliary Feedwater System is required to function during many design basis accidents, including the small break LOCA and secondary pipe ruptures. The Auxiliary Feedwater System is a safety grade system included as part of Cook Plant's engineered safety features. We committed to installing this pump trip on both Units 1 & 2 by January 1, 1981 in response to the NRC recommendations for Auxiliary Feedwater System following their review of the TMI-2 accident.

The Nuclear Safety & Licensing Section's review shows that this RFC is being implemented in a manner that is consistent with the Cook Plant design basis for safety grade protective functions. This automatic trip is a safeguards pump protective function and not a part of the pump actuation logic. The following items have been considered in this RFC:

a) The design includes an independent trip for each pump with a five second time delay to account for spurious tripping (i.e., pumps will be tripped individually),

b) A single failure will not cause the loss of the Auxiliary Feedwater System function,

c) The trip functions are being installed on a train oriented basis and as such diverse power supplies and independence are included,

d) Cables and circuits are being installed as Class 1E and will be routed independently and be high energy line break protected,

e) No separate bypass feature is being installed since it could potentially defeat the purpose of the pump protection on low suction pressure,

f) With a standing auto-start signal (pump still required to function) while regaining adequate suction pressure after a trip on low suction pressure, the operator can restart the pump by manipulating the control switch,

g) Appropriate indications and alarms are being provided in the main control room and failure of these will not affect any essential functions,

h) An appropriate means of testing each trip circuit will be provided (3-way valve, venting sensing line pressure to test),

i) All sensing lines, valves, switches and cabling will be installed as Seismic Class I and qualified for their appropriate operating environment.

The low suction pressure trip setpoint will be calculated conservatively and account for the five second time delay in a manner which precludes possible pump damage during the period of time from when the setpoint is reached to the actual pump trip. This setpoint calculation will consider both the primary (Condensate Storage Tank) and back-up (Essential Service Water) water sources as well as any instrument inaccuracies. Preventing pump damage during plant transients and accidents is the principal concern of this RFC.

RFC DC-12-2460 does not create a substantial safety hazard nor does it constitute an unreviewed safety question as defined in 10CFR50.59. This RFC will provide an adequate level of pump protection and will not, in any way, adversely affect the health and safety of the public.

DC-12-2462

A Reactor Coolant Vent System was installed in both units of the Donald C. Cook Nuclear Plant to fulfill the requirements of NUREG-0737 Item II.B.1.

The Reactor Coolant Vent System is comprised of the Reactor Head Vent System and the Pressurizer Vent System. It has been designed to vent a volume of Hydrogen approximately equal to one-half of the reactor coolant system volume in one hour at system design pressure and temperature.

Each of these subsystems consists of two parallel flow paths one inch in size, with redundant isolation valves in each flow path. A 3/8" orifice has been installed upstream of the isolation valves to limit the flow in the case of a break downstream of the orifices to within the capacity of one centrifugal charging pump. A break of a RCS Vent Line upstream of the orifices would result in a small LOCA not greater than one inch in diameter. This type of break has been analyzed in WCAP-9600 and would behave similarly to the hot leg break presented in this report. Therefore, a break in the vent line would not result in a calculated core uncovery. A locked open hand valve has been installed upstream of the 3/8" orifices.

The isolation valves are DC powered, fail closed, solenoid valves with stem position switches. These valves can be operated from the control room. They will be normally closed during plant operation. Indicating lights will be installed in the control room so the operators will know the valve position. These valves will be qualified to IEEE-323-1974, IEEE-344-1975 and IEEE-383-1972. RTD assemblies have been added downstream of the solenoid valves to detect leakage through these valves. These RTD assemblies will set off an alarm in the control room if leakage through the valves should occur.

The Reactor Vessel Head Vent connects to a part-length control rod drive mechanism housing located near the center of the reactor head. The pressurizer vent is connected to the pressurizer relief line. The possibility of reactor coolant pressure boundary leakage is minimized because of the two isolation valves in series. Isolation valves in one flow path are powered by Train A and the valves in the second flow path are powered by Train B.

Both the Reactor Head Vent and the Pressurizer Vent discharge into the upper volume of the containment at approximate elevation 673'-0", in an area which will provide adequate dilution of any combustible gas.

All piping and equipment used in the Reactor Head Vent from the part-length rod housing to the orifices and all piping and equipment used in the Pressurizer Vent from the pressurizer relief piping to the orifices are designed in accordance with ASME, Section III Class 1 requirements. From the orifices up to the first anchor downstream of the second isolation valve the piping equipment has been designed in accordance with ASME Section III Class 2 requirements. The remainer of the piping is designed to AEP Seismic Class I Level 4.

This RFC is deemed safety related because it involves Seismic Class I equipment and has a potential impact on the plant safety analysis. It was designed and implemented as a direct result of the NRC requirements identified in NUREG-0737 Item II.B.1. The system description and other required documentation was submitted to the NRC on July 15, 1981 in our submitted AEP:NRC:0584.

Based on our review, the implementation of RFC DC-12-2462 does not constitute an unreviewed safety question as defined in 10CFR50.59 nor does it create a substantial safety hazard.

DC-12-2500

Control circuits of certain safety related equipment were modified to prevent changing its emergency mode of operation upon reset of the emergency safeguards (ESF) actuation initiation signal. AEPSC conducted a review of the ESF equipment resets in conformance with the requirements of NRC IE Bulletin 80-06. Our response to the bulletin is documented in our letter of June 20, 1980 (AEP:NRC:00387). The following equipment was modified under this design change:

1) Component Cooling Water Pump Emergency Fans 12-HV-ACCP-2, 12-HV-ACCP-3 control circuits have been modified to allow the fans to continue running after load conservation signal reset.

2) Auxiliary Building Charcoal Filter Dampers 1-HV-AES 1D and 1-HV-AES 2D control circuits were modified to prevent their change of position following reset of Containment Isolation Phase B signal. In addition, a reset push button to defeat the seal in function when it is no longer required has been installed.

3) Containment Air Recirculation Fans 1-HV-CEQ 1 and 1-HV-CEQ 2 control circuits have been modified to prevent the fans from either not starting or tripping following reset of a Containment Isolation Phase B signal. In addition, a white light has been installed at the control switches to indicate that Agastat Timing Relays 62-1 CEQ 1 and 62-1 CEQ 2 are timing.

4) Diesel Generator Test Breakers DGTAB and DGTCD have had their closing circuits modified to prevent the test breakers from reclosing following reset of safety injection or load conservation signal.

The subject RFC is considered to be safety related because the equipment and circuits being modified are Seismic Class I and Class IE, respectively. This ESF equipment is required to function for safe shutdown and mitigation of design basis accidents.

The proposed circuit modification involves the installation of seal-in type circuits in the ESF actuation circuits of the equipment. In addition, the hydrogen skimmer fan delay timers are being converted to DC power operation with an indicating light while the timing is in progress. Also, the seal-in circuit for the ESF equipment room ventilation dampers will be DC powered with an additional component level reset switch (pushbutton) and indicating light to defeat the seal-in when no longer needed. These changes have been reviewed with respect to their impact on the design basis transients and accidents contained in the Cook FSAR and the requirements of IE Bulletin 80-06. Additionally, these changes were reviewed with respect to the operators interface when recovering from a transient or accident that involves resetting of ESF actuation signals such as Phase A or B Containment Isolation and taking manual control of ESF equipment. The results of the review indicate that the changes being implemented under the scope of this RFC are acceptable and consistent with the defense-in-depth philosophy.

RFC DC-12-2500 does not create a substantial safety hazard nor constitutes an unreviewed safety question as defined in 10CFR50.59.

DC-12-2522

A Distributed Ignition System (DIS) which provides additional hydrogen control measures was installed in both units of the Donald C. Cook Nuclear Plant. The purpose of this installation is to provide reasonable assurance that containment integrity would not be threatened by hydrogen explosions following an inadequate core cooling event. The DIS utilizes thermal resistance heating elements (glow plugs) located throughout the containment building. Operation of the DIS will be accomplished by means of manual control switches located in the main control rooms.

The following system description and summary safety evaluation were extracted from our submittal to the NRC AEP:NRC:00500a Attachments 2 and 7, respectively.

The DIS is a two-train system employing seventy (70) igniter assemblies located throughout the containment building. Each train of thirty-five (35) igniter assemblies is further divided into two groups; one group of seventeen (17) assemblies in the general lower volume area including the instrument room, and a second group of eighteen (18) assemblies in the general upper volume area - including the ice condenser upper plenum volume.

Each ignition assembly consists of a General Motors type 7G AC glow plug and a Dongan Electric control power transformer (model 52-20-435) mounted in a sealed box housing. The igniter box is a water tight enclosure meeting NEMA-4 specifications. A copper plate is employed as a heat shield to minimize temperature rise inside the igniter box and a drip shield is utilized to minimize direct water impingement on the thermal element. The transformer is seismically mounted to the igniter box using unistrut. The entire igniter assembly is seismically mounted so as to prevent any possible interferences with safety-related equipment during/after a design basis seismic event.

The normal and emergency power sources for each train of igniters meets Electrical Class 1E specifications and the electrical train separation criteria commensurate with a Class 1E system are maintained in the DIS design. The DIS will be a manual system controllable from the main control room. Two control switches per train are located on auxiliary relay panels A7 and A8 in the main control room. The control switches are of the two-position type, 'off' and 'on', and red and green indicating lights are provided above each switch. Control room annunciation will be provided to indicate loss of power and failure to operate due to hypothetical control circuit equipment malfunctions.

The igniter assembly is a 16" x 12" x 8" enclosure meeting NEMA-4 specifications. The igniter is protected from direct water impingement by a 1/8" steel plate (10" x 18" galvanized steel) drip shield welded to the top of the enclosure. The igniter is mounted to the enclosure through a 6" x 4" x ¼" copper plate to reduce the temperature rise inside the enclosure during periods of combustion. All electrical connections inside the igniter assembly, its associated condulet box, and the two splice boxes per train utilized in the DIS are protected with heat shrink tubing to enhance system performance in an adverse environment. In addition, all DIS cables inside containment are routed in conduit and hence are protected from the environment associated with hydrogen combustion. Access to the interior of the igniter assembly is through a hinged cover plate secured with screws. A bead of silicone rubber has been placed around all bolt holes in the igniter assembly.

Igniter assemblies are distributed throughout the containment to promote combustion of lean hydrogen/air/steam mixtures. The DIS will minimize the potential for hydrogen accumulation and preclude detonations in the unlikely event of a degraded core cooling event similar in nature to the TMI-2 accident involving substantive hydrogen generation. The containment air recirculation/hydrogen skimmer system, in conjuction with upper and lower volume containment sprays, provides sufficient mixing so as to prevent the stratification or pocketing of hydrogen in the various compartments of the containment building.

The DIS is designed to assure combustion of lean hydrogen/air/steam mixtures and hence will minimize the pressure and temperature transients associated with hydrogen combustion. Conservative analyses of the containment response have previously been submitted via our first quarterly report (AEP:NRC:00500). The results of these analyses indicate that deliberate ignition of lean hydrogen mixtures using the DIS will result in pressures below the ultimate strength of the Cook Plant containments. The effects of a hydrogen combustion environment on necessary equipment located inside containment has been evaluated and the results of this evaluation presented in Attachment No. 4 to NRC submittal AEP:NRC:00500a. It is clear from our evaluation that the temperature effects of deliberate hydrogen combustion are less severe than those to which most of the necessary equipment has been qualified (LOCA/MSLB qualification). It has also been shown that the ability to inject emergency core cooling water is not affected by hydrogen combustion.

The extensive plant modifications and enhanced operator training implemented subsequently to the TMI-2 accident have effectively reduced the already low probability of occurrence of events which could result in the generation of substantive amounts of hydrogen at the Cook Plant. The DIS, in conjuction with existing plant equipment, will provide an additional level of mitigation capability for hypothetical events well beyond the design basis of the Cook Units, further enhancing the defense-in-depth philosophy. Installation of the DIS provides further assurance that operation of the Cook Plant will in no way adversely effect the health and safety of the general public.