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DUKE POWER COMPANY

POWER BUILDING
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WILLIAM O. PARKER, JR.
VICE PRESIDENT
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TELEPHONE: AREA 704
373-4083

April 10, 1979

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Mr. James P. O'Reilly, Director
U. S. Nuclear Regulatory Commission
Region II
101 Marietta Street, Suite 3100
Atlanta, Georgia 30303

Re: RII:JPO
50-269
50-270
50-287

Dear Mr. O'Reilly:

Please find attached Duke Power Company's response to IE Bulletins 79-05, -05A transmitted by your letters of April 1, 5, 1979, respectively.

Very truly yours,

William O. Parker, Jr.

William O. Parker, Jr. By HBT

RLG:vr
Attachment

A02
CCP

cc: Director, Division of Reactor Operation Inspection
NRC Office of Inspection and Enforcement
Washington, D. C. 20555

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ITEM 1

In addition to the review of the circumstances described in Enclosure 1 of IE Bulletin 79-05, review the enclosed preliminary chronology of the TMI-2 March 28, 1979 incident. This review should be directed toward understanding the sequence of events to ensure against such an accident at your facility(ies).

Response

The information provided in Enclosure 1 of IE Bulletin 79-05, the preliminary chronology of the recent Three Mile Island Unit 2 occurrence provided in Enclosure 1 of IE Bulletin 79-05A, and various other information obtained relative to the March 28, 1979 TMI-2 incident have been reviewed. Based on this effort, it is currently considered that three significant other-than-normal system/component events were involved in the total incident sequence:

(a) Loss of (normal) feedwater
(b) Loss of auxiliary/emergency feedwater
(c) Uncontrolled depressurization of the reactor coolant system

Subsequent operational activities which appear to have aggravated the above events are considered to be categorized as follows:

(a) Failure to maintain Reactor Coolant System pressure and temperature above saturation conditions and assure adequate core cooling
(b) Uncontrolled (automatic) transfer of radioactive gases and/or liquids from the containment

For Oconee Nuclear Station, with regard to the system/component events listed above, loss of main (normal) feedwater is an anticipated transient. The Oconee units incorporate mitigating systems (emergency feedwater, steam generator pressure control, pressurizer pressure control, and reactor protection) to withstand the effect of the loss of main feedwater flow without exceeding the fuel design limits and the Reactor Coolant System (RCS) design pressure as seen in the FSAR analysis of the loss of electric power transient (FSAR Section 14.1.2.8).

The loss of main feedwater causes a reduction in the heat removal in the RCS, a reduction in the steam flow to the turbine, and initiation of emergency feedwater flow to the steam generators. The reduction in the primary system heat removal would result in an increase in RCS pressure and temperature. The pressurizer pressure control system would actuate pressurizer spray flow when the RCS pressure exceeds the spray actuation setpoint (2205 psig). If pressure continues to increase, the pressurizer power operated relief valve (PORV) would open (setpoint of 2270 psig) releasing steam into the quench tank. If RCS pressure continues to increase, a reactor trip would occur on high RCS pressure (setpoint of 2355 psig).

The turbine control and steam generator protection system would be responding approximately simultaneously with the primary system. Turbine trip because of loss of both main feedwater pumps, opening of turbine bypass valves to provide steam dump into the condenser, and opening of the steam generator atmospheric dump valves if the steam pressure exceeds a valve setpoint would occur. The main feedwater pump trip signal actuates signals to start a turbine driven emergency feedwater pump, to close the main feedwater isolation valves, and to open the auxiliary feedwater header isolation valves in order to provide auxiliary flow. The combined automatic action of the pressurizer PORV, reactor trip, turbine trip, steam dump, and auxiliary feedwater flow results in the safe termination of the transient with the reactor at hot shutdown conditions. Feedwater transients which have occurred at Oconee which resulted in reactor trip are addressed in the response to Item 2.

If a failure of the auxiliary feedwater system occurs following the loss of main feedwater flow, the expected response of a unit would be as follows:

(a) Pressurizer spray flow, PORV operation, and reactor trip would follow a similar course as above.

(b) Turbine trip and steam generator pressure control would also follow a similar course as above.

(c) The steam generator would boil dry.

(d) The RCS would heat up due to decay heat generation with the pressure increasing to the point of steam relief through a pressurizer code safety valve.

(e) The subsequent course of the transient would be similar to the course of complete loss of all station power transient, described in FSAR Section 14.1.2.8.3. The results indicate that operator action would have to be taken within 30 to 90 minutes to provide feedwater flow in a controlled manner. The feedwater flow at this time could be provided by manual action by means of the main feedwater pump, the emergency feedwater pump, the emergency feedwater pumps from one of the other units or the auxiliary service water pump, the flow going into the steam generator either through the auxiliary feedwater header or the main feedwater header. In addition to this operator action, operation of either a reactor coolant pump or a high pressure injection pump would be needed to maintain the system in a stable hot shutdown condition.

Actions taken to assure the availability of auxiliary feedwater are addressed in the responses to Items 5, 7, 8, 10 and 11.

An uncontrolled depressurization of the primary system could occur if a pressurizer relief valve (or valves) is (are) postulated to stick open either during normal operation of a unit or during pressure relief in the event of a transient such as those discussed above. The transient would progress similarly to a small break LOCA. That is, the RCS would depressurize, the reactor would trip on low RCS pressure, (if not already tripped, for example, on high RCS pressure) and ECCS would actuate sequentially (HPI, core flood, and LPI), depending on the degree of depressurization. In addition, the containment cooling and isolation would be initiated if Reactor Building pressure reaches 4 psi. Core uncovering would not occur with the actuation and operation of minimum safeguard systems. The transient is effectively terminated by operator action placing the ECCS in recirculation mode and providing long term decay heat removal capability.

ITEM 1
(Continued)

An incident at Oconee involving a stuck open pressurizer relief valve is addressed in the response to Item 2.

With regard to the operational activities which appear to have adversely contributed to the sequence of events on March 28, 1979 at TMI-2, the responses to Items 3 and 4 address actions taken to assure that, in the event of a similar occurrence at Oconee, RCS pressure and temperature will be maintained above saturation conditions and adequate core cooling will be provided. Actions taken to assure that inadvertent transfer of radioactive gases or liquids from the containment does not occur are addressed in the response to Item 9.

Additional information relative to safe operation of Oconee based on an assessment of the TMI-2 incident and as requested by IE Bulletin 79-05A is provided in the responses to Items 5, 6, 10, 11 and 12.

ITEM 2

Review any transients similar to the Davis-Besse event (Enclosure 2 of IE Bulletin 79-05) and any others which contain similar elements from the enclosed chronology (Enclosure 1) which have occurred at your facility(ies). If any significant deviations from expected performance are identified in your review, provide details and an analysis of the safety significance together with a description of any corrective actions taken. Reference may be made to previous information provided to the NRC, if appropriate, in responding to this item.

Response

Based on initial information relative to the recent Three Mile Island Unit 2 occurrence, Duke Power Company initiated on March 29, 1979 a review regarding similar transients at Oconee Nuclear Station. On March 30, 1979, a summary of this early review was provided verbally to NRC/OIE, Region II. Subsequently, the review of Oconee transients was continued, particularly to address additional TMI-2 information as such became available. At the present time, Oconee transients considered applicable for purpose of the subject review are categorized as follows:

(a) Feedwater Transients Resulting in Reactor Trip
(b) Pressurizer Relief Valve Stuck Open
(c) Loss of Offsite Power

With regard to feedwater transients resulting in reactor trip, Oconee has experienced approximately 42 such incidents as tabulated below:

UNIT	YEAR						
	1973	1974	1975	1976	1977	1978	1979
1	11	1	3	3	2	2	0
2	4	1	4	1	0	3	0
3	N/A	2	1	1	0	2	1

As can be seen, the greatest number of these transients (per unit, per year) occurred during the initial operation of Unit 1 in 1973. Subsequent experience is consistent with classification of this event as one of moderate frequency.

Eleven of the above 42 incidents occurred at or near full power (Unit 1-7, Unit 2-2, Unit 3-2) and demonstrate the ability of the Oconee units to safely respond to such events. Several feedwater transients which resulted in reactor trip have been identified however as involving deviations from expected performance. These and transients in categories (b) and (c) are summarized, in chronological order of occurrence, below:

(1) On January 4, 1974 while operating at 75% full power, Unit 2 tripped due to a loss of off-site electrical power. The reactor coolant pumps (RCP) tripped, and natural circulation cooling was established. RCP seal injection and component cooling were lost for approximately 31 seconds at the

time of the trip. Both were again lost for 15 seconds about 25 minutes after the trip. Subsequently, because pressurizer level was increasing due to excessive makeup flow, an attempt was made to initiate letdown flow, but no flow was indicated. High Pressure Injection (HPI) was secured, and all seal return valves closed in order to reduce makeup volume. A leak was discovered which was the result of a blown gasket on the upstream side of the letdown flow indicator. The letdown line was isolated to control leakage, and the emergency makeup valves were closed. During this time, HPI was turned on again for approximately a minute, then secured again. When the seal return valves were closed, RCP seal cavity pressure went to system pressure. Seal injection flow resumed about 20 minutes later when HPI was once again started.

No design or Technical Specification limits were exceeded during this transient, and the event was not considered to have any safety significance. Hardware and procedural changes were made, however, to provide better monitoring and control during future similar incidents.

(2) On June 13, 1975 while Unit 3 was operating at 15% full power, a feedwater transient resulted in an RCS pressure transient which resulted in the pressurizer power operated relief valve (PORV) opening. The PORV failed to close when pressure decreased and the subsequent RCS depressurization was terminated by closure of the PORV block valve by operator action. Additional information regarding this incident is provided in Mr. William O. Parker's letters of June 27, 1975 and August 8, 1975 to Mr. Norman C. Moseley, Director, NRC/OIE, Region II - see Enclosure 2-1.

(3) On July 12, 1976 while Unit 2 was being shut down in order to repair a main turbine steam leak, the ICS induced an oscillation in feedwater parameters. The feedwater pumps tripped on low feedwater pressure, causing a turbine trip. The trubine trip caused RCS pressure to rise sufficiently to open the pressurizer PORV, relieving pressure to the quench tank. The quench tank rupture disc burst. The PORV reclosed properly when RCS pressure decreased. This RCS transient was of short duration and not observed by the operators who were responding to the turbine trip. The alarm typer, another source of plant equipment status, was out of service. The unit was shut down and turbine repairs were effected, but the quench tank rupture disc was not replaced since its rupture had not been noted. The unit was operated until July 27, 1976, when it was shut down to repair a reactor coolant pump. At that time the burst rupture disc was discovered and replaced.

No design or Technical Specification limits were exceeded during this transient, and the event was not considered to have any safety significante. Operations personnel were subsequently instructed, however, to observe quench tank instrumentation more closely following transients in order to note indications of high quench tank pressure or a burst rupture disc.

ITEM 2
(Continued)

(4) On December 14, 1978, an electrical short in the Unit 1 ICS RCS average temperature (T_{ave}) recorder caused the temperature indication to be approximately 13°F low. To compensate for the low T_{ave} indication, the ICS initiated an increase in power (from approximately 98% full power), but operations personnel had been instructed not to allow power to increase above 99% full power until an earlier problem had been resolved. Therefore, manual control of the reactor was assumed, causing the ICS to switch T_{ave} control from the reactor master to the feedwater master. Feedwater flow decreased to compensate for the -13°F error in the ICS. Upon observing increasing hotleg temperature, decreasing reactor power, and decreasing feedwater flow, operations personnel placed the feedwater master in manual and began increasing feedwater flow. However, before the increasing RCS temperature could be corrected, the reactor tripped on high temperature. Feedwater flow was decreased as rapidly as possible, and the resulting high discharge pressure caused both feedwater pumps to trip. The emergency feedwater pump was started and ran until the feedwater pumps were reset and started. However, the levels in the two steam generators continued to decrease; level in the 1A steam generator reached a low of six inches, while steam generator 1B went dry. Operations personnel opened the feedwater valves and the emergency header block valves in order to feed the steam generators through the emergency feed header. Level was partially restored, although steam generator 1B level remained significantly lower than that of steam generator 1A. This was probably due to the failure of the 1B emergency header block valve to open fully. In order to increase the 1B steam generator level, the emergency feedwater pump was restarted and fed through the emergency header. RCS pressure dropped rapidly due to the quick cooldown of steam generator 1B, causing the feedwater pumps to trip on low suction pressure, and removing feedwater flow from steam generator 1A. Flow was re-established to that steam generator by lining up the emergency feedwater pump to feed it. HPI was initiated when an Engineered Safeguards actuation signal was received due to low RCS pressure. All ES components operated properly.

Additional information regarding this incident is provided in Mr. William O. Parker's letter of January 15, 1979 to Mr. James P. O'Reilly, Director, NRC/OIE, Region II - see Enclosure 2-2.

(5) On December 25, 1978, Unit 1 was at approximately 10% full power and increasing in power following a reactor trip when power to the ICS was lost as a result of blown fuses. When ICS power was lost, both feedwater pumps tripped. The emergency feedwater pump was started, but Control Room instrumentation indicated a discharge pressure of less than 100 PSIG. Personnel were dispatched to increase the discharge pressure to its normal range of 950 to 1000 PSIG. The pump indicated a discharge pressure of 600 PSIG, and it was later determined that the control room instrumentation required approximately five minutes to provide an accurate indication.

Approximately one minute after the feedwater pumps tripped, the reactor tripped on high RCS pressure. When ICS power was lost, the normal feedwater startup header valves began to close and the emergency header block valves opened. Level in steam generator 1A was restored, but 1B went dry. it appears that the block valve failed to open fully. The feedwater pumps were reset and restarted, and flow to the 1B steam generator resumed through the normal feedwater header. The steam generator was dry for approximately 15 minutes.

The reason the emergency header block valve failed to open fully has not been determined. The governor control valve on the emergency feedwater pump has been checked to assure that it is properly set. Operations personnel have been instructed as to actions to take to supply flow to the affected steam generator if flow cannot be established through the startup feed valve and auxiliary feedline immediately after the loss of main feedwater pumps. A procedural change, applicable for all units, has been made requiring operators to bypass the block valve in the event the block valve fails to open. The operator can, from the Control Room, operate one valve to provide emergency feed flow bypassing the block valve to the affected steam generator. The emergency feedwater pump discharge pressure instrument has been adjusted to decrease its response time. This event was not considered to have any safety significance.

ENCLOSURE 2-1