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LIC-92-011R

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Station P1-137
Washington, DC 20555

Reference:
1. Docket No. 50-285
2. Letter from OPPD (W. G. Gates) to NRC (Document Control Desk) dated June 28, 1991 (LIC-91-181A)
3. Letter from NRC (D. L. Wigginton) to OPPD (W. G. Gates) dated October 31, 1991
4. Letter from OPPD (W. G. Gates) to NRC (Document Control Desk) dated November 27, 1991 (LIC-91-314A)

Gentlemen:

SUBJECT: Additional Information on Main Steam Safety Valve (MSSV) Setpoint Drift

In Reference 2, Omaha Public Power District (OPPD) submitted an application for amendment of Technical Specification 2.1.6 on MSSV setpoints. Reference 4 was submitted to respond to the NRC's request for additional information (Reference 3) concerning the application. In a telephone conference on December 13, 1991, a meeting on January 14, 1992, and subsequent discussions, the NRC requested that OPPD supplement References 2 and 4 with the attached additional information.

If you should have any questions, please contact me.

Sincerely,

W. G. Gates

W. G. Gates
Division Manager
Nuclear Operations

WGG/sel

Attachments

c: LeBoeuf, Lamb, Leiby & MacRae
R. D. Martin, NRC Regional Administrator, Region IV
D. L. Wigginton, NRC Senior Project Manager
R. P. Mullikin, NRC Senior Resident Inspector
S. D. Bloom, NRC Project Engineer

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NRC Request #1: **Provide a sensitivity analysis and results for the loss of load and loss of feedwater events. In addition, provide sequence of events data for the loss of load event. Loss of load cases should include (1) nominal (0%) primary safety valve (PSV) drift and main steam safety valve (MSSV) drift of +5%, (2) PSVs inoperable and MSSV drift of +5%, and (3) PSV drift of +3% and MSSV drift of +3%. Summarize peak primary and secondary system pressure data in a table for all cases that have been discussed.**

OPPD Response #1: Tables 3, 4 and 5 (new tables which were not included with Reference 4) provide a sequence of events for the following loss of load cases:

1. Nominal (0%) PSV setpoint drift and +5% MSSV setpoint drift
2. PSV inoperable (10,000 psia) and +5% MSSV setpoint drift
3. +3% PSV setpoint drift and +3% MSSV setpoint drift

Tables 6 and 7 (new tables which were not included with Reference 4) provide a sequence of events for the following loss of feedwater cases:

4. PSV inoperable (10,000 psia) and +3% MSSV setpoint drift
5. Nominal (0%) PSV setpoint drift and +3% MSSV setpoint drift

Table 8 (new table) provides a summary of the peak system pressures for the key analysis cases.

NRC Request #2: **How are the PSVs modeled for Fort Calhoun Station? What are the actual values for the various input parameters?**

OPPD Response #2: The PSV accumulation and blowdown characteristics are shown on the attached Figure B, Rev. 1 (CESEC Code Version 88120). This revision supplements the Figure B (from CESEC Code Version 85055) provided with Reference 4. For Fort Calhoun Station, the P_{set} and P_{acc} values are both modeled as 2525 psia. The A(1), A(2) and A(3) values are all modeled as 1.0, and the A(4) value is 0.7, in accordance with the manufacturer's recommendation for expected safety valve operation. An EG&G Idaho, Inc. valve test program (EGG-NTA-7634 Rev. 1) determined that the PSV has an opening time of 4 - 5 milliseconds. This prompt opening time would have a minor impact on the peak reactor coolant system (RCS) pressure and no effect on the peak secondary pressure (as evidenced by the loss of feedwater event cases 4 and 5 discussed above).

NRC Request #3: **Provide a more specific location for the RCS and steam generator (SG) peak pressure and calculate the pressure drop in the SG during normal operation.**

OPPD Response #3: The peak pressure locations and calculation methods have been reviewed. The RCS peak pressure is located at each reactor coolant pump (RCP) discharge node near the safety injection nozzle. The CESEC code outputs pressure values for two nodes: 1) the pressurizer steam space and 2) the hotleg where the pressurizer surge line is located. CESEC also calculates the pressure differential (dpsi value) between the hotleg node and the RCP discharge node. To determine the peak RCS pressure, the dpsi value must be manually added to the hot leg node value. The peak pressure results from the evaluation are summarized in Table 8.

The SG peak pressure is located at the top of the tube sheet. For conservatism, it is assumed that the CESEC code calculates the SG pressure at the steam outlet nozzle. The pressure drop from the tube sheet to the steam outlet nozzle (neglecting feedwater inlet pressure drops) has been conservatively calculated at 14.4 psia. A normal water level of 32.1 feet in the SG will provide a 10.6 psia hydrostatic head. The hydrostatic head pressure is reduced by 3.4 psia due to pressure losses from the steam separators and other areas. This results in a pressure drop of 7.2 psia between the support plate and the outlet nozzle. For conservatism, this value was doubled and a 14.4 psia pressure drop was used in the evaluation. The peak secondary pressure obtained by manually adding 14.4 psia to the output value from the CESEC code for steam generator pressure is shown in Table 8.

There is a small pressure drop of approximately 2-3 psia from the steam outlet nozzle to the MSSVs, which will not significantly change the MSSV response to secondary pressure transients. The figures furnished with Reference 4 are representative of the RCS and SG responses. The manual additions to the CESEC output values noted above must be performed in order to obtain each system's peak pressure.

NRC Request #4: **Review the pressurizer steam space available during the transients to ensure that the pressurizer does not become water-solid.**

OPPD Response #4: The pressurizer is divided into a water space and steam space which allows the fluids to exist in a non-equilibrium state, depending on the transient event. The pressurizer was confirmed to maintain a steam space in all of the analysis cases. The minimum steam space conservatively calculated during transient Cases 1 through 6 (Table 8) was 30.7%. The feedwater line break, while not a design basis event for Fort Calhoun Station, was also reviewed to determine the minimum steam space during the transient. The minimum steam space identified in Case 7 (Table 8) was 25.5%.

NRC Request #5: **Review and explain the use of the term "significantly" in the discussion and justification section of the amendment request (Reference 2).**

OPPD Response #5: Reference 2 stated: "...peak steam generator pressure would fall significantly below the Safety Limit and design basis acceptance criteria of 1100 psia, as specified in the Updated Safety Analysis Report Section 14.10." In this context, the use of the term "significantly" was inappropriate. Significant is generally defined as a 10% or larger change in the magnitude of a result.

For the loss of main feedwater case with inoperable PSVs and a MSSV drift of +3%, the change in peak secondary pressure is approximately 29 psia (i.e., peak pressure of 1081 psia minus the current USAR peak pressure of 1052 psia = 29 psia) due to the increase in allowable setpoint drift. These pressures do not include the 14.4 psia adjustment described in Response #3. This provides a less than significant margin to the peak secondary system acceptance criteria of 1100 psia.

Although the change in setpoint drift did reduce the margin between the analyzed peak system pressure and the acceptance criterion of 1100 psia, sufficient safety margin is still provided.

NRC Request #6: **Provide more information on the manual trip discussion. Why were the cases run?**

OPPD Response #6: A series of manual trip cases was run to evaluate the system response to a normal reactor trip. The margin to the engineered safety features (ESF) actuation point was noted for each case. It was determined that a -4% MSSV setpoint drift could potentially cause an inadvertent ESF challenge. For conservatism, the allowable setpoint drift was limited to -2%. Of the applicable Licensee Event Reports written by OPPD (76-19, 77-24, 82-20, 84-02, 85-06, 87-03, 88-23, 90-04 and 92-04), none was for a MSSV setpoint drift in the negative direction. Thus, the proposed negative MSSV setpoint drift value should not have an adverse impact on plant safety.

TABLE 3

FORT CALHOUN
SEQUENCE OF EVENTS FOR THE LOSS OF LOAD EVENT
TO MAXIMIZE CALCULATED RCS PEAK PRESSURE

NOMINAL (+0%) PRIMARY DRIFT/+5% SECONDARY DRIFT

Time (sec)	Event	Setpoint or Value
0.0	Loss of Secondary Load	----
9.395	MSSV's Begin to Open	1066 psia
9.665	High Pressurizer Pressure Trip Setpoint is reached	2422 psia
10.165	CEA's Begin to Drop Into the Core	----
10.165	PSV Begins to Open	2525 psia
11.376	Maximum RCS Pressure	2595 psia
12.821	Maximum Steam Generator Pressure	1107.4 psia *

* This case was not used as a basis for the license application change request. This case was adjusted from the Reference 2 submittal to account for the Steam Generator head pressure term.

TABLE 4

FORT CALHOUN
SEQUENCE OF EVENTS FOR THE LOSS OF LOAD EVENT
TO MAXIMIZE CALCULATED RCS PEAK PRESSURE

NO PRIMARY SAFETIES/+5% SECONDARY DRIFT

Time (sec)	Event	Setpoint or Value
0.0	Loss of Secondary Load	----
9.395	MSSV's Begin to Open	1066 psia
9.665	High Pressurizer Pressure Trip Setpoint is reached	2422 psia
10.165	CEA's Begin to Drop Into the Core	----
Non operable	PSV Begins to Open	----
12.856	Maximum RCS Pressure	2735 psia
14.228	Maximum Steam Generator Pressure	1107.4 psia *

* This case was not used as a basis for the license application change request. This case was adjusted from the Reference 2 submittal to account for the Steam Generator head pressure term.

TABLE 5

FORT CALHOUN
SEQUENCE OF EVENTS FOR THE LOSS OF LOAD EVENT
TO MAXIMIZE CALCULATED RCS PEAK PRESSURE

+3% PRIMARY DRIFT/+3% SECONDARY DRIFT

Time (sec)	Event	Setpoint or Value
0.0	Loss of Secondary Load	----
8.48	MSSV's Begin to Open	1045 psia
8.889	High Pressurizer Pressure Trip Setpoint is reached	2422 psia
9.395	CEA's Begin to Drop Into the Core	----
10.728	PSV Begins to Open	2575 psia
11.277	Maximum RCS Pressure	2649 psia
13.146	Maximum Steam Generator Pressure	1092.4 psia

TABLE 6

FORT CALHOUN
SEQUENCE OF EVENTS FOR THE LOSS OF FEEDWATER EVENT
TO MAXIMIZE PEAK SECONDARY PRESSURE

NO PRIMARY SAFETIES/+3% SECONDARY DRIFT

Time (sec)	Event	Setpoint or Value
0.0	Loss of Feedwater	----
30.65	High Pressurizer Pressure Trip Setpoint is reached	2422 psia
31.155	CEA's Begin to Drop Into the Core	----
32.60	MSSV's Begin to Open	1045 psia
Non operable	PSV Begins to Open	----
33.258	Maximum RCS Pressure	2541 psia
35.887	Maximum Steam Generator Pressure	1095.4 psia

TABLE 7

FORT CALHOUN
SEQUENCE OF EVENTS FOR THE LOSS OF FEEDWATER EVENT
TO MAXIMIZE CALCULATED RCS PEAK PRESSURE

NOMINAL (0%) PRIMARY DRIFT/+3% SECONDARY DRIFT

Time (sec)	Event	Setpoint or Value
0.0	Loss of Feedwater	----
30.65	High Pressurizer Pressure Trip Setpoint is reached	2422 psia
31.155	CEA's Begin to Drop Into the Core	----
32.60	MSSV's Begin to Open	1045 psia
----	PSV Begins to Open *	----
33.258	Maximum RCS Pressure	2541 psia
35.887	Maximum Steam Generator Pressure	1095.4 psia

* The peak pressurizer pressure (2515 psia) is less than the PSV setpoint pressure (2525 psia), therefore, the primary safety valves do not open during the loss of feedwater transient event. The maximum RCS pressure accounts for the pressure losses in the RCS as discussed in the response to NRC Request #3.

TABLE 8

SUMMARY OF
SAFETY VALVE SETPOINT ANALYSES

CASE	PSV Drift	MSSV Drift	Peak Primary Pressure	Peak Secondary Pressure
• Loss of Load				
1	0%	+5%	2595 psia	1107.4 psia ***
2	NO	+5%	2735 psia	1107.4 psia ***
3	+3%	+3%	2649 psia	1092.4 psia
• Loss of Feedwater				
4	NO	+5%	2543 psia **	1114.0 psia ***
5	NO	+3%	2541 psia	1095.4 psia
6	0%	+3%	2541 psia	1095.4 psia
• Feedwater Line Break*				
7	NO	+3%	2703 psia	1094.4 psia

PSV = Primary Safety Valve
MSSV = Main Steam Safety Valve
NO = Not Operable

* The feedwater line break is bounded by the main steam line break analysis in the Fort Calhoun design basis. The information is provided above only to assist the NRC in the review of the license application and not to modify the license basis for the plant.

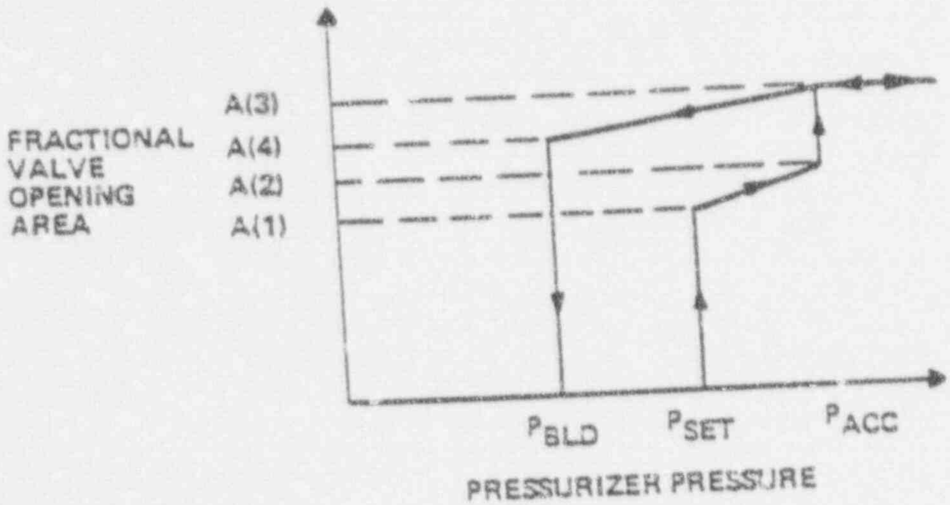
** This case was adjusted from the Reference 2 submittal to account for the dpsi pressure term.

*** This case was not used as a basis for the license application change request. This case was adjusted from the Reference 2 submittal to account for the Steam Generator head pressure term.

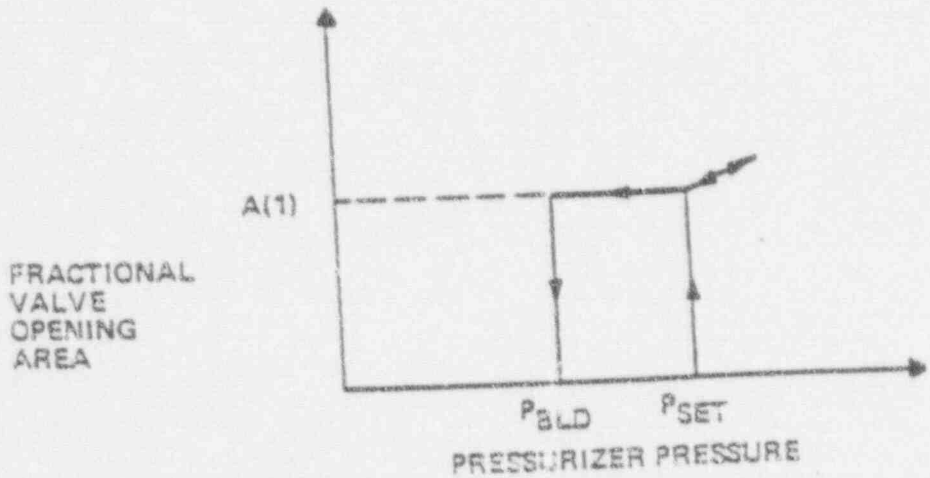
FIGURE B

PRIMARY SAFETY VALVE CHARACTERISTICS

A. PRESSURE REACHES P_{ACC}



B. PRESSURE DOES NOT REACH P_{ACC}



P_{ACC} = ACCUMULATED PRESSURE AT WHICH VALVE FULLY OPENS

P_{SET} = SET PRESSURE AT WHICH VALVE STARTS TO OPEN

P_{BLD} = BLOWDOWN PRESSURE AT WHICH VALVE CLOSES

Rev. 1
12/18/91