

EGG-NTA-8030  
Rev. 1

TECHNICAL EVALUATION REPORT  
TMI ACTION--NUREG-0737 (II.D.1)  
POINT BEACH, UNITS 1 AND 2  
DOCKET NOS. 50-266 AND 50-301

C. Y. Yuan  
C. L. Nalezny  
C. P. Fineman  
M. E. Nitzel

December 1988

Idaho National Engineering Laboratory  
EG&G Idaho, Inc.  
Idaho Falls, Idaho 83415

Prepared for the  
U.S. Nuclear Regulatory Commission  
Washington, D.C. 20555  
Under DOE Contract No. DE-AC07-76ID01570  
FIN No. A6492

8902020599 39 m

## ABSTRACT

Light water reactor operators have experienced a number of occurrences of improper performance of safety and relief valves installed in their primary coolant systems. As a result, the authors of NUREG-0578 (TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations) and subsequently NUREG-0737 (Clarification of TMI Action Plan Requirements) recommended that programs be developed and completed which would reevaluate the functional performance capabilities of Pressurized Water Reactor (PWR) safety, relief, and block valves and which would verify the integrity of the piping systems for normal, transient, and accident conditions. This report provides the results of the review of these programs by the Nuclear Regulatory Commission (NRC) and their consultant, EG&G Idaho, Inc. Specifically, this review examined the response of the Licensee for the Point Beach Nuclear Power Plant, Unit 1 and 2, to the requirements of NUREG-0578 and NUREG-0737 and finds that the Licensee provided an acceptable response, reconfirming that the General Design Criteria 14, 15, and 30 of Appendix A to 10 CFR 50 were met.

FIN No. A6492--Evaluation of OR Licensing Actions-NUREG-0737, II.D.1

## CONTENTS

ABSTRACT .....	ii
1. INTRODUCTION .....	1
1.1 Background .....	1
1.2 General Design Criteria and NUREG Requirements .....	1
2. PWR OWNERS' GROUP RELIEF AND SAFETY VALVE PROGRAM .....	4
3. PLANT SPECIFIC SUBMITTAL .....	6
4. REVIEW AND EVALUATION .....	7
4.1 Valves Tested .....	7
4.2 Test Conditions .....	9
4.2.1 FSAR Steam Transients .....	9
4.2.2 FSAR Liquid Transients .....	10
4.2.3 Extended High Pressure Injection Event .....	11
4.2.4 Low Temperature Overpressure Transients .....	11
4.2.5 PORV Block Valve Fluid Conditions .....	11
4.2.6 Test Conditions Summary .....	12
4.3 Operability .....	12
4.3.1 Safety Valves .....	12
4.3.2 Power Operated Relief Valves .....	16
4.3.3 Electric Control Circuitry .....	19
4.3.4 PORV Block Valves .....	19
4.3.5 Operability Summary .....	20
4.4 Piping and Support Evaluation .....	20
4.4.1 Thermal Hydraulic Analysis .....	20
4.4.2 Stress Analysis .....	25
4.4.3 Piping and Support Summary .....	27
5. EVALUATION SUMMARY .....	28
6. REFERENCES .....	30

## FIGURES

1. Crosby 3K6 valve stem position in Test 506 .....	17
2. Crosby 3K6 valve inlet pressure in Test 506 .....	18

## TABLE

1. EPRI Tests on Crosby HB-BP-86 6M6 Safety Valve .....	14
---	----



TECHNICAL EVALUATION REPORT  
TMI ACTION--NUREG-0737 (II.D.1)  
POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2  
DOCKET NOs. 50-266 AND 50-301

1. INTRODUCTION

1.1 Background

Light water reactor experience has included a number of instances of improper performance of relief and safety valves installed in the primary coolant systems. There were instances of valves opening below set pressure, valves opening above set pressure, and valves failing to open or reseal. From these past instances of improper valve performance, it is not known whether they occurred because of a limited qualification of the valve or because of a basic unreliability of the valve design. It is known that the failure of a power-operated relief valve (PORV) to reseal was a significant contributor to the Three Mile Island (TMI-2) sequence of events. These facts led the task force which prepared NUREG-0578 (Reference 1) and, subsequently, NUREG-0737 (Reference 2) to recommend that programs be developed and executed which would reexamine the functional performance capabilities of Pressurized Water Reactor (PWR) safety, relief, and block valves and which would verify the integrity of the piping systems for normal, transient, and accident conditions. These programs were deemed necessary to reconfirm that the General Design Criteria 14, 15, and 30 of Appendix A to Part 50 of the Code of Federal Regulations, 10 CFR, are indeed satisfied.

1.2 General Design Criteria and NUREG Requirements

General Design Criteria 14, 15, and 30 require that (a) the reactor primary coolant pressure boundary be designed, fabricated, and tested so as to have an extremely low probability of abnormal leakage, (b) the reactor coolant system and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions are



not exceeded during normal operation or anticipated transient events, and (c) the components which are part of the reactor coolant pressure boundary shall be constructed to the highest quality standards practical.

To reconfirm the integrity of overpressure protection systems and thereby assure that the General Design Criteria are met, the NUREG-0578 position was issued as a requirement in a letter dated September 13, 1979 by the Division of Licensing (DL), Office of Nuclear Reactor Regulation (NRR), to ALL OPERATING NUCLEAR POWER PLANTS. This requirement has since been incorporated as Item II.D.1 of NUREG-0737, Clarification of TMI Action Plan Requirements (Reference 2), which was issued for implementation on October 31, 1980. As stated in the NUREG reports, each pressurized water reactor Licensee or Applicant shall:

1. Conduct testing to qualify reactor coolant system relief and safety valves under expected operating conditions for design basis transients and accidents.
2. Determine valve expected operating conditions through the use of analyses of accidents and anticipated operational occurrences referenced in Regulatory Guide 1.70, Rev. 2.
3. Choose the single failures such that the dynamic forces on the safety and relief valves are maximized.
4. Use the highest test pressures predicted by conventional safety analysis procedures.
5. Include in the relief and safety valve qualification program the qualification of the associated control circuitry.
6. Provide test data for Nuclear Regulatory Commission (NRC) staff review and evaluation, including criteria for success or failure of valves tested.

7. Submit a correlation or other evidence to substantiate that the valves tested in a generic test program demonstrate the functionability of as-installed primary relief and safety valves. This correlation must show that the test conditions used are equivalent to expected operating and accident conditions as prescribed in the Final Safety Analysis Report (FSAR). The effect of as-built relief and safety valve discharge piping on valve operability must be considered
  
8. Qualify the plant specific safety and relief valve piping and supports by comparing to test data and/or performing appropriate analysis.

## 2. PWR OWNERS' GROUP RELIEF AND SAFETY VALVE PROGRAM

In response to the NUREG requirements previously listed, a group of utilities with PWRs requested the assistance of the Electric Power Research Institute (EPRI) in developing and implementing a generic test program for pressurizer power operated relief valves, safety valves, block valves, and associated piping systems. The Wisconsin Electric Power Co., owner of the Point Beach Nuclear Power Plant, Units 1 and 2, was one of the utilities sponsoring the EPRI Valve Test Program. The results of the program are contained in a group of reports which were transmitted to the NRC by Reference 3. The applicability of these reports is discussed below.

EPRI developed a plan (Reference 4) for testing PWR safety, relief, and block valves under conditions which bound actual plant operating conditions. EPRI, through the valve manufacturers, identified the valves used in the overpressure protection systems of the participating utilities. Representative valves were selected for testing with a sufficient number of the variable characteristics that their testing would adequately demonstrate the performance of the valves used by utilities (Reference 5). EPRI, through the Nuclear Steam Supply System (NSSS) vendors, evaluated the FSARs of the participating utilities and arrived at a test matrix which bounded the plant transients for which overpressure protection would be required (Reference 6).

EPRI contracted with Westinghouse Electric Corp. to produce a report on the inlet fluid conditions for pressurizer safety and relief valves in Westinghouse designed plants (Reference 7). Since Point Beach, Units 1 and 2, were designed by Westinghouse this report is relevant to this evaluation.

Several test series were sponsored by EPRI. PORVs and block valves were tested at the Duke Power Company Marshall Steam Station located in Terrell, North Carolina. Additional PORV tests were conducted at the Wyle Laboratories Test Facility located in Norco, California. Safety valves were tested at the Combustion Engineering Company, Kressinger Development



Laboratory, located in Windsor, Connecticut. The results for the relief and safety valve tests are reported in Reference 8. The results for the block valves tests are reported in Reference 9.

The primary objective of the EPRI/C-E Valve Test Program was to test each of the various types of primary system safety valves used in PWRs for the full range of fluid conditions under which they may be required to operate. The conditions selected for test (based on analysis) were limited to steam, subcooled water, and steam to water transition. Additional objectives were to (a) obtain valve capacity data, (b) assess hydraulic and structural effects of associated piping on valve operability, and (c) obtain piping response data that could ultimately be used for verifying analytical piping models.

Transmittal of the test results meets the requirement of Item 6 of Section 1.2 to provide test data to the NRC.

### 3. PLANT SPECIFIC SUBMITTAL

The plant specific evaluation of the adequacy of the overpressure protection system for Point Beach, Units 1 and 2, was submitted by Wisconsin Electric Power Co. to the NRC on April 8, 1982 (Reference 11 and 12). Additional information on the plant specific evaluation of the safety and relief valves and safety/relief valve piping and supports was submitted on December 23, 1982 (Reference 13). A request for additional information was transmitted to Wisconsin Power by the NRC on February 12, 1985 (Reference 14). Response to NRC request for additional information and a final evaluation report were submitted by Wisconsin Power on May 16, 1985 (Reference 15). A second request for information was sent to Wisconsin Power on July 2, 1987 (Reference 16). The Licensee responded to this request on August 24, 1987 (Reference 17).

The response of the overpressure protection system to Anticipated Transients Without Scram (ATWS) and the operation of the system during feed and bleed decay heat removal are not considered in this review. Neither the Licensee nor the NRC have evaluated the performance of the system for these events.

#### 4. REVIEW AND EVALUATION

##### 4.1 Valves Tested

The Point Beach, Units 1 and 2, overpressure protection systems are equipped with two (2) safety valves, two (2) PORVs, and two (2) PORV, block valves. The safety valves are 4-in. Crosby Model HB-BP-86, 4K26, spring loaded valves with loop seal internals. The design set pressure is 2485 psig and the rated steam flow capacity is 288,000 lbm/h. The PORVs are Copes-Vulcan Model D-100 globe valves with D-100-160 operators and the opening set pressure of the PORVs is 2335 psig. Unit 1 uses one 3 in. valve with 316 SS stellited plug and 17-4 PH cage and one 2 in. valve with 17-4 PH plug and cage. Unit 2 uses two 2 in. valves with 17-4 PH plug and cage. The 2 in. and 3 in. valves represent the old and new designs of the Copes-Vulcan PORV of the same model. The PORV block valves are 3-in. Velan Model B10-3054B-13M gate valves with Limatorque SMB-000-5 motor operators. The inlet piping to the safety valves include hot loop seals (average temperature is 424°F); the inlet to the PORVs have no loop seals.

The Crosby 4K26 safety valve used at Point Beach, Units 1 and 2, was not specifically tested in the EPRI safety and relief valve testing program. Two similar valves, which were tested by EPRI, are the Crosby HB-BP-86, 3K6 and 6M6 valves. These valves are of the same design but vary in orifice size and flow capacity. A comparison of the size and capacity of these valves is shown below.

<u>Valve</u>	<u>Model</u>	<u>Inlet Diameter (in.)</u>	<u>Outlet Diameter (in.)</u>	<u>Nozzle Bore Diameter (in.)</u>	<u>Rated Flow (lbm/h)</u>
Point Beach	4K26	4	6	1.800	288,000
Test	3K6	3	6	1.536	212,182
Test	6M6	6	6	2.154	420,006

The difference in orifice size only affects the valve capacity but not valve behavior. Other differences, such as body construction and disk holder type and material variations, do not have a significant effect on the valve operability. The valves were tested with a long inlet piping



configuration with loop seals similar to the safety valve installation at Point Beach, Units 1 and 2. The results of the applicable EPRI tests on these valves, therefore, adequately demonstrate the operability of the Point Beach safety valves.

A 3 in. Copes-Vulcan PORV identical to the 3 in. Copes-Vulcan PORV used at Point Beach Unit 1 was tested in the EPRI test program. Two sets of similar tests were conducted on this valve. One set used the 17-4 PH plug and cage and the other used 316 SS stellited plug and 17-4 PH cage. Point Beach uses both the 2 in. and 3 in. valves in its two units. The main differences between the 2 in. and 3 in. valves are in the valve body construction and in the valve plug material. The two different plugs were both used in the tests. The difference in body construction is not expected to have a significant effect on the valve operability. Since the 3 in. valve body may experience a little larger thermal effect than the 2 in. body, using the 3 in. valve in the tests would conservatively represent both the 2 in. and 3 in. valves. Therefore, the EPRI test results of the Copes-Vulcan PORV are directly applicable to the Point Beach PORVs.

The PORV block valve used in the EPRI tests was the Velan Model B10-3054B-13MS gate valve, identical to those used at Point Beach, Units 1 and 2. But the Limitorque operators, SB-00-15 and SMB-00-10, used for the test valves are larger than the SMB-000-5 operator used at Point Beach. However, the maximum torque capacity of the larger operators was not fully used in the tests, because the torque switches of these operators were not set at the highest positions. By comparing the manufacturer's specifications for these operators, it was determined that the SMB-000-5 operator used at Point Beach, Units 1 and 2, is capable of delivering a torque equal to or exceeding those used in the tests. Since the in-plant valves have the same capabilities as the test valves, the applicable EPRI test results can be used to evaluate the operability of the Point Beach PORV block valves.

Based on the above, the valves tested are considered to be representative of the in-plant valves at Point Beach, Units 1 and 2, and to have fulfilled the part of the criteria of Items 1 and 7 as identified in Section 1.2 regarding applicability of the test valves.

## 4.2 Test Conditions

Point Beach, Units 1 and 2, are both two-loop PWRs designed by the Westinghouse Electric Corp. The valve inlet fluid conditions that bound the overpressure transients for Westinghouse designed PWR Plants are identified in Reference 7. The transients considered in this report include FSAR transients, extended high pressure injection, and low temperature overpressurization events. The expected fluid conditions for each of these events and the applicable EPRI tests are discussed in this section.

### 4.2.1 FSAR Steam Transients

The limiting event resulting in steam discharge through the safety valves and steam discharge through both the safety valves and PORVs is the locked rotor accident.

The safety valves are predicted to experience a peak pressure of 2682 psia and a pressurization rate of 240 psi/s (Reference 7). The maximum developed backpressure at the safety valve outlet ranges from 546 psia to 635 psia among the four safety valves in Point Beach, Units 1 and 2. The average loop seal temperature was calculated to be 424°F (Reference 15).

No steam tests directly applicable to the Point Beach safety valves were found in the EPRI tests on the Crosby 3K6 safety valve. Two steam tests (No. 506 and 508) were performed using the manufacturer recommended ring settings and a drained loop seal. The peak pressures at valve opening were 2709 psia in Test 506 and 2508 psia in Test 508, and the pressurization rates were less than 4.1 psi/s. The peak backpressures were over 455 psia. The pressurization rates, backpressure, and the peak pressure were less severe than those expected in Point Beach, Units 1 and 2. These tests cannot be considered directly applicable to the in-plant valves because they were run with a drained loop seal instead of the hot loop seals used at Point Beach. But, since the drained loop seal tests represent a less severe valve discharge condition than the filled loop seal case, any valve discharge problem encountered in the drained loop seal tests will most probably occur with a filled loop seal.

Among the EPRI tests performed on the 6M6 valve, Tests 1415 and 1419 were run with a hot loop seal and manufacturer recommended ring settings. The peak pressures in these tests were greater than 2675 psia, and the pressurization rate was 350 psi/s. The backpressure of 255 psia was less than that of the in-plant valve (565 psia). Since the maximum backpressure does not develop until after the loop seal is discharged and full steam flow conditions achieved, a cold water loop seal test (Test 929), with a peak backpressure of 710 psia, will be used to demonstrate valve operability with respect to backpressure. The pressurization rate during Test 929 was 319 psi/s which also bounds the plant response. Based on the above comparison, it is concluded that results of Tests 1415, 1419, and 929 on the 6M6 safety valve are representative of the Point Beach safety valves.

When both the safety valve and PORV are actuated in a FSAR transient resulting in steam flow, the maximum pressure and pressurization rate are predicted to be 2573 psia and 202 psi/s, respectively (Reference 7). In the EPRI tests on the Copes-Vulcan relief valve, the maximum pressure at valve opening was 2715 psia which bounds the predicted pressure at Point Beach. The backpressure developed at the outlet of the PORVs is not an important consideration for the air operated PORVs used at Point Beach. The air operated PORV is not sensitive to backpressure (Reference 6). Therefore, the EPRI test inlet fluid conditions for the PORV in steam discharge are representative of the plant specific transient conditions.

#### 4.2.2 FSAR Liquid Transients

The most limiting transient resulting in liquid discharge through the safety valves and PORVs is the feedline break accident. The feedline break event for Point Beach, Units 1 and 2, was not addressed in the Westinghouse report on valve inlet fluid conditions (Reference 7). According to the Licensee in Reference 15, a loss of normal feedwater from a pipe break, pump failure, or valve malfunction was analyzed and reported in Section 14.1.10 of the Point Beach FSAR. The results of the analysis showed that no water discharge through the safety valve or PORV would occur. Therefore, water discharge through the valves is not expected in a FSAR transient for the Point Beach plant.



#### 4.2.3 Extended High Pressure Injection Event

The limiting extended high pressure injection event is the spurious actuation of the safety injection system at power. According to the Westinghouse analysis in Reference 7, no fluid discharge is expected through either the safety valve or PORV.

#### 4.2.4 Low Temperature Overpressurization Transient

Only the PORVs are used for low temperature overpressure protection (LTOP). The safety valves are not affected in this transient. The plant specific range of potential fluid conditions for low temperature overpressure events were presented in Reference 15. For water discharge, the peak inlet pressure is up to approximately 2350 psia and liquid temperatures from 70 to 350°F. For steam/liquid discharge the inlet pressure ranges from 400 to 2350 psia and the liquid temperature is the associated saturation temperature. If there is a steam bubble in the pressurizer, the inlet pressure is up to 2350 psia and the temperature up to 650°F.

There were two low pressure and temperature water tests performed on the Copes-Vulcan PORV with stellite plug and 17-4 PH cage similar to the in-plant valves. The tests were conducted at an inlet pressure of 675 psia and at temperatures of 105 and 442°F, respectively. The high pressure/temperature tests on the Copes-Vulcan PORV were discussed in Section 4.2.1. These inlet fluid conditions of the EPRI tests adequately envelop the expected inlet fluid conditions of Point Beach, Units 1 and 2.

#### 4.2.5 PORV Block Valve Fluid Conditions

The PORV block valves are required to operate over the same range of fluid conditions as the PORVs. In the EPRI tests, the block valve was only tested at full pressure (to 2500 psia) steam conditions. The operability of the block valves under water flow conditions was not directly addressed in the EPRI tests. However, the Westinghouse gate valve closing tests (Reference 9) demonstrated that the required torque to open or close the

valve depended almost entirely on the differential pressure across the valve disk and was insensitive to the momentum load. Therefore, the required force is nearly independent of the type of flow (i.e., water or steam). Furthermore, according to friction tests done by Westinghouse on a stellite coated specimen, the friction coefficient between stellite surfaces is approximately the same for steam and water tests. In some instances, the friction coefficient in water is lower than in steam. The Velan block valves have stellite coated disk and seats. The force required to overcome disk friction in steam is essentially equal to the force required in water. Therefore, the steam tests are adequate to demonstrate the operability of the block valves for expected water conditions.

#### 4.2.6 Test Conditions Summary

The test sequences and analyses described above demonstrate that the test conditions bound the conditions for the plant values. They also verify that Items 2 and 4 of Section 1.2 were met, in that conditions for the operational occurrences were determined and the highest predicted pressures were chosen for the test. The part of Item 7, which requires showing that the test conditions are equivalent to conditions prescribed in the FSAR, was also met.

### 4.3 Operability

#### 4.3.1 Safety Valves

The Point Beach safety valves are expected to pass steam only. Steam discharge tests (No. 506, 508, 1415, 1419) performed on Crosby 3K6 and 6M6 safety valves were discussed in Section 4.2.1. The tests directly applicable to the Point Beach safety valves are the water seal discharge tests (No. 1415 and 1419) on the 6M6 safety valve. The valve opened within  $\pm 2\%$  of the design set pressure and closed with 5.1 to 9.4% blowdown. Rated flow was achieved at 3% accumulation with valve lift positions at 92 to 94% of rated lift. In Test 929, the cold loop seal test used to bound valve performance with high backpressure, the valve had stable performance on steam and closed with 5.1% blowdown adequately demonstrating valve operability at high backpressures.

The valve in Test 1415 performed stably, but in Test 1419 it did not perform very well. In Test 1419, the valve chattered on closing and the test was terminated after the valve was manually opened to stop the chatter. This result does not indicate a valve closing problem for the Point Beach safety valve since an identical test (Test 1415) already demonstrated that the valve performed satisfactorily and exhibited no sign of instability. The closing chatter in Test 1419 may be a result of the repeated actuation of the valve in loop seal and water discharge tests. As shown in Table 4.3.1 on the next page, the 6M6 test valve was subjected to seventeen steam, water and transition tests. In the first four or five tests, the valve fluttered and chattered during loop seal discharge but stabilized and closed successfully. After Test 913, there were four instances in which the test was terminated due to chattering on closing. Galled guiding surfaces and damaged internal parts were found during inspection and the damaged parts were refurbished or replaced before the next test started. The test results showed that the valve performed well after each repair, but the closing chatter recurred in a subsequent test. Test 1415 was performed immediately after valve maintenance and the valve performed stably. The next test (Test 1419) encountered chatter in closing even though it was a repeat of Test 1415 at similar fluid conditions. This suggests that inspection and maintenance are important to the continued operability of this valve. Therefore, the Licensee should inspect the safety valves after each lift involving loop seal or water discharge and a formal procedure should be developed and incorporated into the plant operating procedures or licensing documents such as the plant technical specifications.

Tests 506 and 508 were performed on the Crosby 3K6 valve with a drained loop seal. As noted in Section 4.2.1, several parameters in these tests were less severe than those expected at the plant. Review of these tests is appropriate, however, because of problems with the valve during the tests. In Test 506, the valve missed the setpoint by 200 psig and experienced flutter during closing. Prior to Test 508, the valve adjusting bolt was raised by 2.3 flats to decrease the setpressure by an estimated 161 psi. The valve opened at 2507 psia but chattered during closing. The valve was manually opened to terminate the chatter and the test.



TABLE 4.3.1 EPRI TESTS ON CROSBY HB-BP-86 6M6 SAFETY VALVE

Seqn No.	Test No.	Ring Setting	Test Type	Stability	Leakage	
					Pre (gpm)	Post (gpm)
1	903	1	Steam	Stable	0	0
2	906a,b,c	1	L.S.	Stable	0	0
3	908	1	L.S.	f/c	0	0
4	910	1	L.S.	f/c	0	0
5	913	2	L.S.	f/c	0	1.0
6	914a,b,c	2	L.S. Transition	Terminated	0	Large
7	917	3	L.S.	f/c	0	0
8	920	3	L.S.	Terminated	0	0
9	923	3	L.S.	f/c	0	0
10	926a,b,c,d	3	Transition	Stable	0.36	0.08
11	929	4	L.S.	f/c	0	0
12	931a,b	4	L.S. Transition	c	0	0
13	932	4	Water	Terminated	0	--
14	1406	4	L.S.	f/c	0	0.63
15	1411	4	Steam	Stable	0.76	0.37
16	1415	4	L.S.	Stable	0	0
17	1419	4	L.S.	Terminated	0	1.5

c--chatter

f/c--flutter/chatter

L.S.--loop seal

Ring setting--four different sets of ring settings were tested. Actual ring positions not shown.

Terminated--Test terminated after valve was manually opened to stop chatter.

The situation with these two 3K6 tests is similar to the two 6M6 tests discussed above. Prior to Test 506, the valve was refurbished. During the test the valve, although it fluttered on closing, did not chatter and was able to close without operator intervention. Before Test 508, only the setpoint pressure was adjusted. According to the test report no internal parts were refurbished. In the test the valve chattered on closing and the operator manually terminated the test by opening the valve. These tests results reinforce the conclusion above that the Licensee should inspect the safety valves after each lift involving loop seal or water discharge to ensure proper operation during subsequent operation.

The blowdown in these tests (5.1 to 9.4%) were in excess of the 5% value specified by the valve manufacturer and the ASME Code. Westinghouse performed an analysis, "Safety Valve Contingency Analysis in support of the EPRI Safety/Relief Valve Testing Program--Volume 3: Westinghouse Systems," EPRI NP-2047-LD, October 1981, on the effects of increased blowdown and concluded that no adverse effects on plant safety occurred in that the reactor core remained covered. Therefore, the amount of increased blowdown occurred in the Crosby 6M6 steam tests is considered acceptable.

A bending moment induced at the outlet flange of the Crosby 3K6 safety valve during the EPRI tests was 133,000 in-lb and the valve performance was not affected. This bending moment is higher than the maximum bending moment of 124,000 in-lb calculated for the Point Beach safety valves (Reference 15). This indicates that the moment loading on the safety valve does not affect the operability of the Point Beach safety valves.

The stability of the plant safety valves was assessed by comparing the inlet piping pressure drop for the plant and EPRI test facility on valve opening and closing. For valve opening the plant pressure drop was calculated to be 373 psid compared to pressure drops of 391 and 263 psid for the Crosby 3K6 and 6M6 test valves, respectively. In addition, in References 18 and 19, data was provided that showed the Crosby 3K6 valve opened stably during tests with an opening pressure drop between 432 and 462 psid. This indicated the plant valves should be as stable as the test valves during opening. During closing, the plant pressure rise was calculated to be 221 psid compared to a pressure rise of 194 psid for the

3K6 valve and 181 psid for the 6M6 valve. Thus, the plant pressure rise is 13.9% greater than the pressure rise determined for the EPRI test facility. For two reasons, however, it is concluded the plant valves should operate stably during valve closing. First, the 3K6 valve was stable during valve opening in tests with an inlet pressure drop greater than that measured during the EPRI tests. This indicates the pressure difference in the EPRI facility is not necessarily bounding with respect to acceptable valve operation. Secondly, as shown in Figures 4.3.1-1 and 4.3.1-2, the 3K6 valve closed stably in Test 506 even though the pressure rise on valve closure was approximately 400 psid. These figures were taken from Reference 20.

#### 4.3.2 Power Operated Relief Valve

Steam discharge through the Point Beach PORV is predicted for the FSAR transients. No liquid discharge is expected except for the low temperature overpressurization event. The EPRI tests indicated that the valve opened and closed on demand and within the required opening and closing time of 2.0 s. The lowest steam flow rate observed in the tests (255,600 lbm/h) is much higher than the rated flow of 210,000 lbm/h for the Point Beach PORVs.

The maximum bending moment induced on the discharge flange of the PORV during the EPRI tests was 43,000 in-lb. The operability of the valve was not affected by the applied load. The predicted maximum bending moment on one of the Point Beach PORVs associated with the combined effect of dead weight, SSE, and valve discharge loads is 45,810 in-lb. This exceeds the maximum bending moment tested by approximately 7%. The calculated bending moments for the other three valves are near 27,000 in-lb, which is well below the test value of 43,000 in-lb. Also, the 43,000 in-lb bending moment was only the highest bending moment applied in the EPRI tests. It does not represent the actual limit beyond which valve operability will be impaired. Since the amount the plant bending moment exceeds the test bending moment is relatively small, and the bending moment was calculated for a conservative load combination, the higher value predicted for one of the valves is considered acceptable. Thus the operability of the Point Beach PORVs is demonstrated.



TE : 4/29/82  
TIME : 10/7/23

EPRI/CE VALVE TEST  
SEQ/TEST NO. : 5/CK-02-02/506  
VALVE MFG. : CROSBY  
SERIAL NO. : NONE  
TEST DATE: 8/11/81  
TEST TIME: 5:7:36

DATA ACQUISITION PROGRAM REV. 12.11  
READINGS PER SECOND: 10000/ PLOT INC. : 0.0000 SEC.

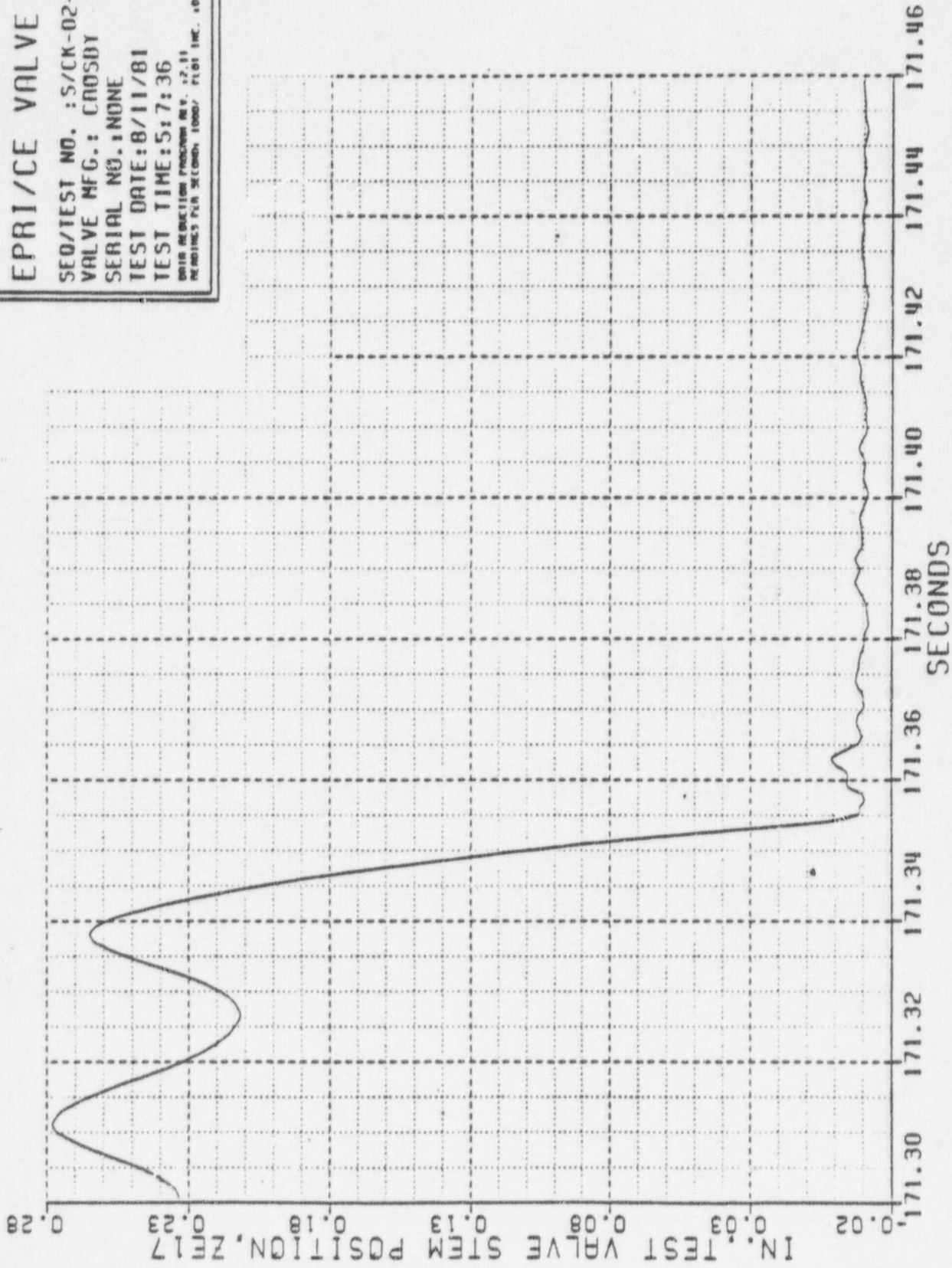
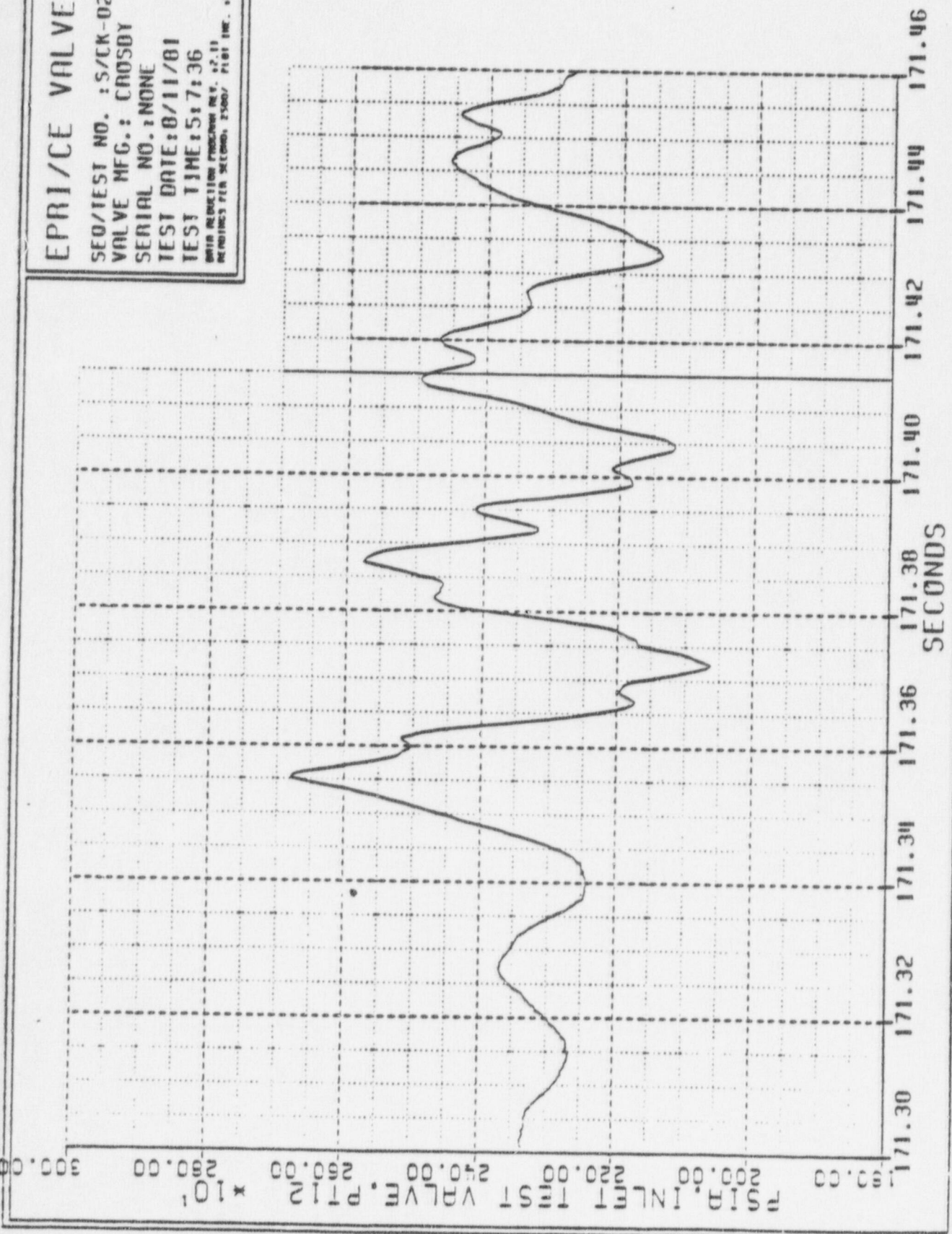


Figure 4.3.1-1 Crosby 3K6 valve stem position in Test 506.

DATE: 10/10/49

# EPRI/CE VALVE TEST

SEQ/TEST NO.: S/CK-02-02/506  
 VALVE MFG.: CROSBY  
 SERIAL NO.: NONE  
 TEST DATE: 8/11/81  
 TEST TIME: 5:7:36  
DATA ACQUISITION PROGRAM REV. 12.11  
 RECORDS PER SECOND: 2500/ 1181 INCH. x 8.0000 SEC.



EPRI FORM 100-1000 (10/78)

EPRI

Figure 4.3.1-2 Crosby 3K6 valve inlet pressure in Test 506.

#### 4.3.3 Electric Control Circuitry

NUREG-0737 II.D.1 required qualification of the associated control circuitry as part of the safety and relief valve qualification task. The specific electric circuits under consideration are the control circuits of the PORVs. Meeting the licensing requirements of 10 CFR 50.49 for this circuitry is considered satisfactory and specific testing per NUREG-0737 requirement is not required. According to the Licensee the environmental qualification of the PORV control circuitry was reviewed and found to be in compliance with the requirements of 10 CFR 50.49 by the NRC (Reference 21). Therefore, the requirements of NUREG-0737 regarding the qualification of PORV control circuitry is considered satisfied.

#### 4.3.4 PORV Block Valves

The Velan PORV block valve was cycled 21 times against full steam flow in the EPRI testing program. Steam pressure upstream of the block valve varied from 2440 to 2500 psia during the opening cycles and between 2340 and 2410 psia during the closing cycles. The stroke times of the test valve were 9.7 s to 9.9 s, which are within the required stroke time of 10.0 s. Tests for water flow through the Velan block valve were not performed in the EPRI test program. As explained in Section 4.2.5 of this report, the valve behavior under water flow conditions is expected to be similar to that of the full pressure steam tests. Thus, the operability of the valves for liquid flow condition was indirectly demonstrated.

The Point Beach PORV block valves use a smaller Limitorque operator (SMB-000-5) than the SB-00-15 and SMB-00-10 operators used in the EPRI tests. In Reference 15, the Licensee discussed why the EPRI test results were adequate to demonstrate operability of the plant block valve even though the plant valve operator is smaller than those tested. The torque switch of the plant SMB-000-5 operator is set at 3.0. The SMB-000-5 operator delivers a torque of 100 ft-lb with this torque switch setting. A number of tests were performed on the Velan valve at lowered torque switch settings to investigate valve operability at reduced operator torque. It was found that the test valve opened and closed satisfactorily even when the



torque switch in the SB-00-15 or the SMB-00-10 operator was set at 1.0, which corresponded to a torque of 82 ft-lb (Reference 9). Based on the results of the EPRI tests, the torque provided by the SMB-000-5 operator is more than adequate to assure the operability of the Point Beach block valve.

#### 4.3.5 Operability Summary

The above discussion and test results demonstrate that the Point Beach PORVs, PORV block valves, and safety valves would operate satisfactorily under the expected operating and accident conditions. Therefore, the part of Item 1 of Section 1.2 of this report, which requires conducting tests to qualify the valves, Item 5, which requires qualification of the associated control circuits, and the part of Item 7, which requires that the effect of discharge piping on operability be considered, were met provided the Licensee documents a formal procedure for the inspection of the safety valves as discussed in Section 4.3.1.

### 4.4 Piping and Support Evaluation

This evaluation covers the piping and supports upstream and downstream of the safety valves and PORVs extending from the pressurizer nozzle to the pressurizer relief tank. The piping was designed for deadweight, internal pressure, thermal expansion, earthquake and safety relief valve discharge conditions. The calculation of the time histories of hydraulic forces due to valve discharge, the method of structural analysis, and the load combinations and stress evaluations are discussed below.

#### 4.4.1 Thermal Hydraulic Analysis

Pressurizer fluid conditions were selected for use in the thermal hydraulic analysis such that the calculated valve discharge forces would bound the forces for any FSAR and HPI events, including the single failure that would maximize the forces on the valve. The peak pressurizer pressure and pressurization rate used in the thermal hydraulic analysis were 2778 psia and 297 psi/s, respectively. These conditions exceed those calculated for Westinghouse two-loop plants as shown in Reference 7. The loop seal

liquid was assumed to be at a pressure of 2778 psia with temperatures ranging from approximately 200°F at the safety valve inlets to 650°F at the steam/water interface. The temperature distribution was based on a heat balance for the insulated box surrounding the loop seal piping. In the analysis, water above 350°F was assumed to flash to steam across the safety valve. The remaining water was distributed downstream of the safety valves, as discussed in Reference 22, to determine the size of the water slug. As an additional conservatism, the temperature distribution used in the water slug downstream of the safety valves was assumed to be that of the discharge piping (148 to 210°F) instead of that calculated for the loop seal temperature profile. The forces from the discharge of the loop seal water under the above conditions would bound those from other possible conditions at the plant.

The PORVs are used for low pressure overpressure protection at Point Beach, Units 1 and 2, but conditions representative of this transient (water discharge) were not analyzed. The PORVs were only subjected to steam discharge conditions. This raised a concern about whether the conditions analyzed would bound the forces the PORV piping would be subjected to during a LTOP transient. This was a concern because the PORV liquid flow rate at the pressures and temperatures possible during an LTOP transient at Point Beach, Units 1 and 2, (see Section 4.2.4) is much greater than the full steam flow rate. When liquid at these temperatures and flow rates was discharged by the PORV, it could flash in the downstream piping and the two-phase mixture could impose significant loads on the piping. Depending on the amount of flashing, the LTOP loads could exceed the steam discharge loads. Use of hand calculations to bound the LTOP load condition was not successful because of the many variables that could affect the load calculation: PORV liquid flow rate, fluid temperature, downstream piping pressure transient, and the amount of flashing and the resulting quality of the two-phase mixture. Because LTOP transient conditions were not analyzed, there is a potential problem regarding the Point Beach, Units 1 and 2, discharge piping; however, this is not considered by the NRC staff to be in the scope of the Item II.D.1 review. Therefore, this issue will be reviewed separately, at a later time, and will not impact the NUREG-0737, Item II.D.1, review for Point Beach, Units 1 and 2.

The thermal hydraulic analysis for Point Beach, Units 1 and 2, was completed using only one valve actuation sequence. The valve actuation sequence analyzed assumed both the safety valves and PORVs opened simultaneously at a pressure of 2778 psia. In Reference 17, the Licensee provided additional justification on why this sequence was considered to produce the maximum piping loads. For the safety valve discharge piping (up to the point where it joins the relief system common discharge header) it was noted that the maximum forces were calculated to occur within the first 0.075 s of the transient. At this time the PORVs were less than 10% open and their discharge had little effect on the system. Therefore, assuming the PORVs opened at the same time as the safety valves had little influence on the calculated piping loads in this part of the system. Also, the peak loads in the common discharge header occur within the first 0.24 s when the PORVs were less than half open. Based on these considerations it can be concluded that the peak forces in the discharge piping from the exit of the safety valves to where it enters the quench tank are a result of the safety valve discharge of the loop seal water. Assuming the PORVs discharged simultaneously with the safety valves did not result in a significant reduction in the calculated loads because they were less than half open when the peak loads in this portion of the system were calculated.

The peak loads on the PORV discharge piping, from the valve exit to the point where it joins the common discharge header, were calculated to occur within the first 0.119 s of the transient. The PORVs are less than 15% open at this point. The Licensee stated that the timing of the peak load is consistent with the passage of the loop seal in the safety valve discharge piping and, because the PORV were less than 15% open, the peak load in this part of the system was not significantly influenced by the PORV actuation. If the forces from the PORV actuation were significant, a higher load would have been calculated later in the transient as the PORV continued to open. Therefore, the peak loading induced on this portion of the piping comes from the safety valve discharge piping.



One concern not directly addressed by the Licensee is the affect of the safety valve actuation on the backpressure in the PORV discharge piping. This has the potential to reduce the loads because the higher backpressure could reduce the flow velocity in the piping downstream of the PORVs. This could be significant at Point Beach, Units 1 and 2, because of the high backpressures generated during the safety valve discharge (640 psia). The data in Reference 20 was reviewed to determine how rapidly the backpressure builds up in the safety valve discharge piping. This would give an estimate of the backpressure affecting the PORV actuation. For Test 526, the backpressure at the safety valve outlet was less than 200 psia for the first 1.5 s of the test. The backpressure in the PORV discharge piping would be even less. Therefore, the contribution from the safety valve discharge to the backpressure in the PORV downstream piping is relatively small even after the PORVs have fully opened and are at full flow. This, in conjunction with the fact the PORVs were assumed to actuate at 2778 psia, 428 psi above their actual setpoint, would indicate the calculated piping loads in the PORV discharge piping would not be larger if the PORVs were assumed to open and the safety valves assumed to stay closed.

The thermal hydraulic analysis was performed using the RELAP5/MOD1 computer code. The ability of RELAP5/MOD1 to calculate the thermal hydraulic transient was verified through simulations of EPRI/CE SRV tests, as documented in Reference 22. Force time histories on the piping system at changes in flow direction were generated from RELAP5/MOD1 output using the REFORC program. The REFORC code was also previously reviewed. It was found to yield acceptable results for load cases such as were analyzed.

The valve flow rates used in the analysis were reviewed. In Reference 15, it was stated the valve rated flow rate was used for the safety valves and PORVs. Because the PORVs do not have loop seals, use of the PORV rated flow is reasonable because the loads from the valve actuation do not constitute a large part of the overall piping load. Also, as noted above, the peak loads in the PORV discharge piping are due to forces transmitted from the safety valve piping during the passage of the loop seal. When questioned further on the flow rates used in the analysis, the Licensee stated in Reference 17 that the calculated safety valve flow rate

varied from 122 to 111% of the rated flow over the first 0.11 s. The Licensee did not clarify why the information given in the two responses was different but the calculation of greater than rated flows was probably due to the high pressure (2778 psia) modeled at valve opening. The flow decreased as the simulated pressurizer pressure decreased. The Licensee noted the loop seal slug reached maximum velocity prior to the calculated flow dropping below 111% of the rated flow and the momentum would not be significantly affected by the decrease in driving flow. Also, the peak loads in the discharge piping occurred within 0.119 s for the piping upstream of the relief system common discharge header and within 0.24 s at the entrance to the relief tank. Therefore, for a major portion of the system the peak loads occurred before the calculated flow rate dropped below the valve theoretical flow rate. The Licensee also noted that for the forces calculated on the common discharge header, the influence of the PORV flow merging with the safety valve flow, as they enter the common header, more than compensated for the reduction in driving force on the loop seal slug due to the decreased safety valve flow. It should also be noted that the measured flows during the applicable EPRI tests were less than 109% of rated flow. Based on this discussion, the calculated flow rates used in the analysis are considered reasonable.

In Reference 15, it was stated that the model nodalization tried to be detailed enough to prevent underestimation of the piping forces due to numerical smearing. The volume size was decreased in regions where hydrodynamic behavior was expected to change rapidly and the control volume size was maintained less than or equal to the loop seal volume, which is adequate. Valve opening times were 20 ms for the safety valves and 0.8 s for the PORVs. The opening time of the safety valves is representative of the opening times measured in the EPRI tests. The PORV opening time, however, is about 60% longer than the opening times measured in the EPRI tests. The Licensee evaluated the impact of using a valve opening time of 0.49 s, which is representative of the opening times measured in the EPRI tests, by considering the axial forces generated on the upstream and downstream PORV piping for each valve opening time. For the downstream piping, the calculated loads increased by only 1%, and upstream the total

load increased from 10 to 22 lbf for the faster opening time. These differences are not significant. Based on this information the thermal hydraulic analysis is considered acceptable.

#### 4.4.2 Stress Analysis

In the piping and support evaluation, the safety valve and PORV piping between the pressurizer nozzles and the pressure relief tank were analyzed. The requirements of the ANSI B31.1 Power Piping Code, 1967 edition, with stress intensification factors from the 1973 edition were used as the governing code for the piping. The governing structural code for the support analyses was the AISC Code, 8th Edition. Load combinations used in the analyses were consistent with the EPRI guidelines. The piping was analyzed for thermal expansion, pressure, weight, earthquake, plant operational thermal and pressure transients, and safety valve and PORV discharges.

The structural analysis for the safety valve and PORV piping was performed using the Impell Corporation computer code SUPERPIPE. SUPERPIPE performs static, dynamic response spectra, and transient dynamic analyses. It also performs the required load combinations, code verifications, and support load calculations. The SUPERPIPE code was found to be verified in an acceptable manner.

Because the only case the Licensee analyzed was a combined safety valve/PORV discharge (i.e., he did not analyze a separate PORV actuation case), the results of an upset load combination, whereby the normal, operational basis earthquake, and PORV discharge are combined, could not be analyzed. In response to a question in Reference 16, the Licensee reviewed the results of their piping analysis and concluded the results of the faulted load combination analyzed bounded the upset load combination. The Licensee justified this position in Reference 17. He stated that for the piping downstream of the safety valves and PORVs the stresses were dominated by the passage of the loop seal water during the safety valve discharge. Because the peak stresses in the PORV discharge piping could be attributed to the passage of the loop seals from the safety valves and the calculated



stresses decreased once the loop seal passed, even though the PORVs were still opening, the Licensee concluded the piping stresses downstream of the PORVs would not be greater if the PORVs were calculated to open alone. As noted above, this reasoning was considered acceptable. For the piping upstream of the PORVs, the Licensee evaluated the piping stresses due to a modified upset load combination against the upset allowable,  $1.2 S_h$ . In this case, the PORV discharge loads were replaced by the loads calculated during the safety valve/PORV transient analyzed by the Licensee. The PORV upstream piping met this allowable except for the area near the PORVs. The higher stresses in this area could be directly attributed to the passage of the loop seal from the safety valves. Therefore, had the case where only the PORVs actuated been analyzed, the loads would have met the  $1.2 S_h$  allowable. This discussion is adequate to justify not analyzing an upset load combination directly.

As previously mentioned, the piping analysis was performed in accordance with the requirements of the 1967 edition of the ANSI Power Piping Code. The load combination equations and stress limits used for the evaluation of the piping stresses upstream and downstream of the safety valves and PORVs are consistent with the EPRI guidelines. The first analysis of the piping systems by the Licensee's consultant in 1982 showed severe overstress conditions would exist as a result of a transient load application. The safety valve inlet piping was enclosed in insulated boxes to raise the loop seal water temperature and reduce the severity of the transient loads. Several pipe supports were modified and/or added to reduce stresses. The modified system was reanalyzed and the results showed all piping stresses were within allowable limits except for one point on the Unit 2 discharge piping near the relief tank. The stress for the combined thermal expansion plus sustained loads was 42,405 psi while the allowable limit is 41,740 psi. Although, technically, the governing piping code was not satisfied, this overstress is only 1.5%. The Licensee noted several conservative assumptions were used in the analysis which would increase the stresses for this load case. Thus, it is concluded this overstress is acceptable for this specific case and that the actual operating stresses in the area of concern will not cause a loss of function of the piping.

The supports were analyzed to the requirements of the AISC Code, 8th Edition. AISC limits were used for normal and occasional loads and 1.33 times AISC limits were used for the faulted loads. In Reference 17, the Licensee clarified the support load combinations presented in Reference 15. This information verified acceptable load combinations were used in the analysis. Reference 17 also provided a comparison of the calculated and allowable support loads. This comparison showed code allowables were met for all supports. Information in Reference 17 also demonstrated the factors of safety required by IE Bulletin 79-02 were maintained for all supports using concrete anchor bolts. A safety factor of 4.0 and 5.0 was used for wedge type anchors and sleeve type anchors, respectively, to establish allowable loads for all load combinations.

#### 4.4.3 Piping and Support Summary

The analysis discussed above, demonstrating that a bounding case was chosen for the piping configuration, verifies Item 3 of Section 1.2 was met. In addition, the analysis of the piping and support system verifies that Item 8 of Section 1.2 was met.

## 5. EVALUATION SUMMARY

The Licensee for the Point Beach, Units 1 and 2, provided an acceptable response to the requirements of NUREG-0737, and thereby reconfirmed that the General Design Criteria 14, 15, and 30 of Appendix A to 10 CFR 50 were met. The rationale for this conclusion is given below.

The Wisconsin Electric and Power Co. participated in the development and execution of an acceptable relief and safety valve test program designed to qualify the operability of prototypical valves and to demonstrate that their operation would not invalidate the integrity of the associated equipment and piping. The subsequent tests were successfully completed under operating conditions which by analysis bounded the most probable maximum forces expected from anticipated design basis events. The generic test results and piping analyses showed that the valves tested functioned correctly and safely for all relevant steam discharge events specified in the test program and that the pressure boundary component design criteria were not exceeded. Analysis and review of the test results and the Licensee's justifications indicated direct applicability of the prototypical valve and valve performances to the in-plant valves and systems intended to be covered by the generic test program. The plant specific piping also was shown by analysis to be acceptable.

The NRC's acceptance of the safety valves is contingent upon the Licensee recognizing the potential effects of chatter on valve operability and developing a method to ensure continued, reliable safety valve operation. This would include developing procedures for inspection and maintenance of the safety valves following each valve actuation involving loop seal or water discharge and incorporating these into the plant operating procedures.

Thus, the requirements of Item II.D.1 of NUREG-0737 were met (Items 1-8 in Paragraph 1.2) and, thereby demonstrate by testing and analysis, that the reactor primary coolant pressure boundary will have a low probability of



abnormal leakage (General Design Criterion No. 14) and that the reactor primary coolant pressure boundary and its associated components (piping, valves, and supports) were designed with sufficient margin such that design conditions are not exceeded during relief/safety valve events (General Design Criterion No. 15). Furthermore, the prototypical tests and the successful performance of the valves and associated components demonstrated that this equipment was constructed in accordance with high quality standards (General Design Criterion No. 30).

## 6. REFERENCES

1. TMI Lessons Learned Task Force Status Report and Short-Term Recommendations, NUREG-0578, July 1979.
2. Clarification of TMI Action Plan Requirements, NUREG-0737, November 1980.
3. D. P. Hoffman, Consumers Power Co., letter to H. Denton, NRC, "Transmittal of PWR Safety and Relief Valve Test Program Reports," September 30, 1982.
4. EPRI Plan for Performance Testing of PWR Safety and Relief Valves, July 1980.
5. EPRI PWR Safety and Relief Valve Test Program Valve Selection/Justification Report, EPRI NP-2292, January 1983.
6. EPRI PWR Safety and Relief Valve Test Program Test Condition Justification Report, EPRI NP-2460, January 1983.
7. Valve Inlet Fluid Conditions for Pressurizer Safety and Relief Valves in Westinghouse-Designed Plants, EPRI NP-2296, January 1983.
8. EPRI PWR Safety and Relief Test Program Safety and Relief Valve Test Report, EPRI NP-2628-SR, December 1982.
9. R. C. Youngdahl, Consumers Power Co., letter to H. Denton, NRC, "Submittal of PWR Valve Data Package," June 1, 1982.
10. EPRI PWR Safety and Relief Valve Test Program Guide for Application of Valve Test Program Results to Plant-Specific Evaluations, Revision 2, Interim Report, July 1982.
11. C. W. Fay, Wisconsin Electric Power Co. to H. R. Denton, NRC, "Preliminary Evaluation of PWR Safety and Relief Valve Test Program Results" March 1982.
12. C. W. Fay, Wisconsin Electric Power Co. to H. R. Denton, NRC, "Further Response to NUREG-0737, Item II.D.1, Point Beach Nuclear Plant, Units 1 and 2," April 8, 1982.
13. C. W. Fay, Wisconsin Electric Power Co. to H. R. Denton, NRC, "Further Response to NUREG-0737, Item II.D.1, Relief and Safety Valve Testing, Point Beach Nuclear Plant, Units 1 and 2," December 1982.
14. NRC Request for Additional Information, February 12, 1985.
15. R. W. Britt, Wisconsin Electric Power Co. to H. R. Denton NRC, "NUREG-0737, Item II.D.1, Performance Testing of Relief and Safety Valves, Point Beach Nuclear Plant, Unit 1 and 2," May 16, 1985.

16. D. W. Wagner, NRC, letter to C. W. Fay, Wisconsin Electric Power Co., "Request for Additional Information - NUREG-0737, Item II.D.1, Performance Testing of Relief and Safety Valves (TACS44608 & 44609)," July 12, 1987.
17. C. W. Fay, Wisconsin Electric Power Co. to NRC Document Control Desk, "Docket NOS. 50-266 and 50-301, NUREG-0737 Item II.D.1, Performance Testing of Relief and Safety Valves, Point Beach Nuclear Plant," August 24, 1985.
18. R. W. Koher, Rochester Gas and Electric Corp., letter to NRC Document Control Desk, "NUREG-0737, Item II.D.1 - Performance Testing of Relief and Safety Valves," June 2, 1987.
19. R. W. Koher, Rochester Gas and Electric Corp., letter to NRC Document Control Desk, "NUREG-0737, Item II.D.1 - Performance Testing of Relief and Safety Valves," June 4, 1987.
20. W. R. Hocking, et al., EPRI/CE Safety Valve Test Report, Volume 5 of 10, TEST RESULTS FOR CROSBY VALVE, MODEL HB-BP-86, 3K6, Interim Report, July 1982.
21. C. W. Fay, Wisconsin Electric Power Co. letter to H. R. Denton, NRC, "Resolution of Safety Evaluation Reports for Environmental Qualification of Safety Related Electrical Equipment, Point Beach Nuclear Plant, Units 1 and 2, (Item 2 of System V in Enclosure 2), November 23, 1983.
22. Application of RELAP5/MOD1 for Calculation of Safety and Relief Valve Discharge Piping Hydrodynamic Loads, EPRI-2479, December 1982.