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AUTH.NAME AUTHOR AFFILIATION
TUCKER,H.B. Duke Power Co.
RECIP.NAME RECIPIENT AFFILIATION
DENTON,H.R. Office of Nuclear Reactor Regulation, Director
STOLZ,J.F. Operating Reactors Branch 4

SUBJECT: Forwards response to NRC 850603 request for addl info on NUREG-0737,Item III.D.1, "Performance Testing of Relief & Safety Valves." PORV control circuit components located in cable room & not subj to harsh environ.

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DUKE POWER COMPANY
P.O. BOX 33189
CHARLOTTE, N.C. 28242

HAL B. TUCKER
VICE PRESIDENT
NUCLEAR PRODUCTION

TELEPHONE
(704) 373-4531

October 1, 1985

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Attention: Mr. J. F. Stolz, Chief
Operating Reactors Branch No. 4

Subject: Oconee Nuclear Station
Docket Nos. 50-269, -270, -287

Dear Sir:

By letter dated June 3, 1985, the NRC requested additional information on NUREG-0737, Item III.D.1, "Performance testing of Relief and Safety Valves". My letter of August 6, 1985 advised you of a delay in the submittal of a response.

Please find attached Duke's response for Oconee Nuclear Station.

Very truly yours,

H.B. Tucker / HD

Hal B. Tucker

PFG:slb

Attachment

cc: Dr. J. Nelson Grace, Regional Administrator
U. S. Nuclear Regulatory Commission
Region II
101 Marietta Street, NW, Suite 2900
Atlanta, Georgia 30323

Ms. Helen Nicolaras
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Mr. J. C. Bryant
NRC Resident Inspector
Oconee Nuclear Station

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Duke Power Company
Oconee Nuclear Station
Attachment 1
Response to NRC's
Request For Additional Information
Concerning Performance Testing
Of Relief and Safety Valves

REQUEST 1:

The B&W valve inlet fluid conditions report indicated the SRV and PORV could pass water for extended HPI events. The report indicated water relief would continue until the steam generators were able to remove decay heat with auxiliary feedwater and operator action was taken to secure HPI, but it did not state how long this might be. The EPRI valve test program included water tests of the SRV and PORV but the test report did not state the test duration for the SRV and the test duration for the PORV was short. Provide the following information because long periods of water flow has the potential to damage valve guides, seats, etc. and thus affect valve operability. Make a comparison between the expected duration of water flow conditions through the SRV and PORV in Oconee and the duration of the EPRI water tests to demonstrate operability of the SRV and PORV will not be impaired. If the duration of the water flow conditions expected in Oconee exceed the test times, provide evidence showing the extended water flow conditions will not impair valve operability.

RESPONSE 1:

Potential for valve damage from water flow occurred in the EPRI test program only for specific cases. These cases are not applicable to the Oconee valve applications.

The Dresser 31739A safety valve exhibited stability problems and potential for damage on water flow only for the long inlet piping configuration. All water tests performed with the short inlet configuration exhibited stable behavior. The Oconee inlet piping is shorter than the EPRI short inlet piping and is expected to provide stable performance on water.

The Dresser Model 31533VX-30 PORV exhibited problems on water flow only for the loop seal simulation tests. These tests had the valves open on relatively cold (approximately 100°F) water and transition to hot water for closing. The resulting thermal transient affected valve operability. The Oconee PORV's are mounted directly on the pressurizer with no loop seal and will not be subject to rapid thermal transients.

The EPRI tests demonstrated that operability of neither of the above valves would be affected by water flow.

REQUEST 2:

EPRI tests of Dresser safety valve 31739A showed valve blowdown generally exceeded the design blowdown of 5% regardless of the valve ring settings. B&W report 77-1135671-00 (August 1982), Pressurizer Safety Valve Maximum Allowable Blowdown, indicated that blowdowns of up to 20% are acceptable because natural circulation was not impeded with blowdowns of that magnitude. The report showed, however, that with the larger valve blowdown the pressurizer did fill and liquid was discharged from the SRV. The report recommended safety valve blowdown be limited to less than 20%. Discuss what will be done at Oconee 1, 2, and 3 assure that safety valve blowdown will be less than 20%. Provide test data to demonstrate Oconee SRVs will have less than 20% blowdown. Also, since the report indicated the pressurizer will fill due to the larger blowdown, include liquid discharge due to excessive blowdown in the discussion of question 1.

RESPONSE 2:

The CDI analysis (Reference 1) providing the optimized ring settings predicted a blowdown of 12.6%. This was supported by comparison to EPRI test data. Reference the response to Request 6 & 7 for a comparison to test data.

REQUEST 3:

The B&W valve inlet fluid condition report identified Oconee 1, 2, and 3 as being covered by the cold overpressure protection section of the report. The B&W report identified the conditions at the PORV inlet as low pressure steam because operator action could be used to mitigate the transient at 10 min and longer than 10 min was required to fill the pressurizer. Water solid operation of the system never occurs. Since no low pressure steam tests were performed for the PORVs, confirm that the high pressure steam tests demonstrate operability for the low pressure steam case for both opening and closing of PORVs.

RESPONSE 3:

Oconee performs a PORV Operability Test, (PT/0/A/201/04), at 45 psig of steam prior to each start-up.

In addition, the PORV is tested at Wyle Labs at 50 psig, 500 psig and 2200 psig regularly after maintenance is performed. These tests have adequately demonstrated PORV opening and closing under low pressure steam conditions.

REQUEST 4:

The backpressures expected for the SRVs and PORVs in Oconee 1, 2, and 3 were not discussed in the plant submittal. Since the backpressure could affect valve operability, discuss the expected backpressures for the SRVs and PORVs and demonstrate that the expected backpressures in Oconee were enveloped by the EPRI tests.

RESPONSE 4:

Based on analysis performed by Duke, the expected worst case backpressure for the safety valves is 578 psia which was enveloped by the test data. Reference the response to Question 6 & 7 for a comparison to test data.

The PORV backpressure would be a maximum when the safety valves are also open, since they share a common discharge pipe. EPRI Wylie test 10-DR-15, 760 psia, would bound the upper and EPRI Marshall tests 6 through 10, 170-175 psia, bound the lower case. Valve performance in all of the above tests was satisfactory.

VALVE LOADING SUMMARY VS EPRI TEST VALVES

Largest Loading Combination Compared

Units 1 & 2

VALVE (Flange)	LOADING COMBINATION	PREDICTED VALUE	LOADING COMBINATION	PREDICTED VALUE	EPRI STEADY STATE TEST LOAD
PORV (Inlet)	Normal	2921 ft-lbs[1]	UPS2	3985 ft-lbs[1]	2125 ft-lbs
PORV (Outlet)	Normal	2080 ft-lbs	UPS2	2397 ft-lbs[1]	2125 ft-lbs
SRV's					
RC-67 (Inlet)	Normal	1036 ft-lbs	UPS2	10,657 ft-lbs	20,144 ft-lbs
RC-67 (Outlet)	Normal	541 ft-lbs	UPS2	4,653 ft-lbs	20,144 ft-lbs
RC-68 (Inlet)	Normal	544 ft-lbs	UPS2	5,031 ft-lbs	20,144 ft-lbs
RC-68 (Outlet)	Normal	215 ft-lbs	UPS2	1,602 ft-lbs	20,144 ft-lbs

Unit 3

VALVE	LOADING COMBINATION	PREDICTED VALUE	LOADING COMBINATION	PREDICTED VALUE	EPRI STEADY STATE TEST LOAD
PORV (Inlet)	Normal	402 ft-lbs	UPS2	1,480 ft-lbs	2,125 ft-lbs
PORV (Outlet)	Normal	155 ft-lbs	FAULTED	816 ft-lbs	2,125 ft-lbs
SRV's					
RC-67 (Inlet)	Normal	864 ft-lbs	UPS2	10,774 ft-lbs	20,144 ft-lbs
RC-67 (Outlet)	Normal	826 ft-lbs	UPS2	4,831 ft-lbs	20,144 ft-lbs
RC-68 (Inlet)	Normal	450 ft-lbs	UPS2	5,247 ft-lbs	20,144 ft-lbs
RC-68 (Outlet)	Normal	294 ft-lbs	UPS2	1,947 ft-lbs	20,144 ft-lbs

Note (1)

The Unit 1 & 2 normal operating moments and the upset moments exceed the EPRI Steady State Test Value for the PORV. The largest component of the upset loading combination is the normal moment. The dynamic transient moment contributes approximately 27% (inlet side) and 13% (outlet side) to the upset loading. All Oconee Units' PORVs have provided twelve years of satisfactory in-service operation with the applied normal operating loads, therefore, these moments are judged satisfactory.

REQUEST 5:

Bending moments are induced on the safety valves and PORV during the time they are required to operate because of discharge loads and thermal expansion of the pressurizer tank and inlet piping. Predicted plant moments were not identified in the plant submittal. Make a comparison between the predicted plant moments with the moments applied to the test valve to demonstrate that the operability of the plant valves will not be impaired.

RESPONSES:

Shown below are (2) valve moment summaries for the inlet and outlet of the PORV and the two SRV's. Actual moments are applicable to Units 1 & 2 and Unit 3.

LOAD CASES CONSIDERED (Load Case Abbreviation Name)

(1) Gravity (GRAV)

(2) Thermal: T_{hot} = 500° F and thermal anchor motion (THRM)

(3) Operational Basis Earthquake (OBE)

(4) Safety Relief Valve Discharge: Valves open 1,2,3,RC-67,-68 (SRV)

(5) Power Operated Relief Valve and Safety Relief Valve Discharge:
Valves Open 1,2,3,RC-67.&68; 1,2,3,RC-04 (WATR)

LOADING COMBINATIONS

(1) NORMAL = GRAV + THRM

(2) UPSET = GRAV + THRM + OBE
OR
GRAV + OBE
LARGEST OF TWO SUBCASES

(2) UPS 2 = GRAV + THRM + ENVELOPE (SRV & WATR)
OR
GRAV + ENVELOPE (SRV & WATR)
LARGEST OR TWO SUBCASES

(3) FAULTED = GRAV + THRM + 2X(OBE)
OR
GRAV + 2X (OBE)
LARGEST OF TWO SUBCASES

REQUEST 6:

The Oconee 1, 2, and 3 plant safety valves are Dresser 31739A spring loaded valves which was one of the valves EPRI chose for testing. EPRI testing of the Dresser 31739A valve was performed at various ring settings. The submittal did not identify clearly the applicable EPRI tests which demonstrate operability of the plant safety valves by referencing the appropriate test numbers or providing the current plant ring settings. The submittal mentioned that, "with the 'reference' ring settings selected for the later tests, the valve exceeded rated flow for all tests except one." The reference ring settings referred to in the submittal are identified in the EPRI Test Condition Justification Report as upper, -48, middle, -40, and lower, +11. However, it is not clear from the submittal that these reference ring settings are the same as the current plant ring settings. If the current plant rings settings were not used in the EPRI tests, the results may not be directly applicable to the Oconee 1, 2, and 3 safety valves. Identify the Oconee 1, 2, and 3 safety valve ring settings. If the plant specific ring settings were not tested by EPRI, explain how the expected values for flow capacity, blowdown, and the resulting back pressure corresponding to the plant specific ring settings were extrapolated or calculated from the EPRI test data. Identify these values and evaluate the effect of these values on safety valve behavior.

RESPONSE 6:

See Response to Request 7.

REQUEST 7:

The submittal stated Duke Power Co. was working with valve vendors/consultants to determine optimum safety valve ring settings for Oconee 1, 2, and 3. When the optimum ring settings are identified, provide the settings to be used. If the identified ring settings are different than current ring settings, demonstrate valve operability based on EPRI testing or by providing information similar to that requested in Question 6 if current ring settings differ from those used in EPRI testing.

RESPONSE 7:

Through the B&W Owners Group, an analysis (Reference 1) was performed to optimize safety valve ring settings for the specific conditions of six B&W nuclear plants including Oconee Units 1, 2, and 3. Continuum Dynamics, Inc. (CDI) used the valve dynamic simulation code COUPLE, which was validated against the EPRI safety valve data (Reference 2). The study optimized the safety valve ring settings for the expected range of conditions that occur in B&W plants.

The resulting ring settings for Oconee are:

	Optimum	Current
Upper Ring:	-48 Notches	-48 Notches
Middle Ring:	-50 Notches	-40 Notches
Lower Ring:	+8 Notches	+8 Notches

Comparison to EPRI Tests

EPRI tests 322 and 324 have middle ring settings of -40 and-60, respectively, which bound the optimum Oconee setting of -50. The backpressures were 609 psia and 664 psia, respectively, which exceed the Oconee worst case expected backpressure 578 psia. Both tests provided stable performance, full lift and flow, and had blowdowns of 11.1% and 12.6%, respectively.

Tests 316, 318, and 326 all use the bounding middle ring setting (-40, -40, -60 respectively) backpressures of 195, 195, and 196 psia, respectively. These tests bound the lower backpressure case and demonstrate stable performance with full lift and flow.

Comparison of tests 322 (+11 lower) and 1012 (+3 lower) at a -40 middle ring settings and 324 (+11 lower) and 1011 (+5 lower) at -60 middle ring setting show that performance is not sensitive to lower ring settings. These settings bound the Oconee lower ring settings and all tests demonstrated stable results with full flow. The changes in blowdown observed are indicative of the variation in developed backpressures.

Conclusion

The Oconee safety valve ring settings have been optimized by analysis and shown to provide stable operation and full lift and flow by comparison to EPRI test data.

The Oconee safety valves currently have the reference -40 middle ring settings in use. These are scheduled to be changed to -50 at the next scheduled outage for each unit.

REQUEST 8:

EPRI testing of the Dresser 31739A safety valve with reference ring settings using 400°F water (Test 1114) indicated the valve was not able to relieve the system pressure during the test. In addition the valve only opened to a partial lift position. The B&W valve inlet fluid condition report indicated that 400°F water is a possible safety valve inlet condition for B&W 177-FA plants which include Oconee 1, 2, and 3. The Oconee submittal stated that preliminary system analyses indicated the amount of flow passed in each subcooled water test was sufficient to prevent an overpressure condition in Oconee. Discuss the details of these analyses and/or otherwise demonstrate the ability of the Dresser 31739A safety valve to relieve the system pressure at Oconee 1, 2, and 3 if it must pass 400°F water. Otherwise, discuss what pressure relief system modifications will be implemented to assure an overpressure condition will not arise if the safety valve must pass 400°F water.

RESPONSE 8:

An analysis was performed by Duke to determine whether the Dresser 31739A safety valves would be able to relieve system pressure at Oconee when passing 400°F water. The maximum pressurizer insurge flow rate was calculated for the limiting transient which would involve 400°F water relief. This insurge flow rate was compared to the amount of flow indicated by Test 1114 for subcooled water relief. The test indicated a greater relief flow through two safety valves at 2550 psia than the calculated maximum insurge flow. 2550 psia is only 50 psi above the valve lift setpoint and well below the Reactor Coolant System (RCS) pressure safety limit of 2750 psia. Therefore the Dresser 31739A safety valves are capable of relieving system pressure at Oconee if they must pass 400°F water.

The limiting transient for maximum insurge flow was identified as a steam line break from hot full power with no reactor coolant pump trip and full unthrottled high pressure injection (HPI) flow. This would result in reaching 400°F water relief conditions in the minimum time after reactor trip, thus maximizing the core decay heat. It was assumed that a steam line break caused a RCS cooldown to 400°F, and the pressurizer was then filled to water solid conditions by unthrottled HPI flow. The minimum time to reach this condition was calculated to be 11.3 minutes, but 10 minutes was assumed for conservatism. It was assumed that there was no heat removal from the steam generators at that time, so all of the heat from the core and the four reactor coolant pumps was absorbed by the reactor coolant, causing the fluid to expand and flow out the surge line. This flow was combined with the surge line flow caused by unthrottled HPI to obtain the total maximum calculated surge line flow of 436,500 lbm/hr. EPRI Test 1114 indicates that at least 500,000 lbm/hr would be expected through two safety valves at 2550 psia. Therefore, the relief capacity of the safety valves is adequate for 400°F water.

It should be noted that the calculation was performed with conservative assumptions, e.g., maximum decay heat, maximum injection flow, no steam generator heat removal when relieving water, and no pressurizer PORV available. Furthermore, this limiting scenario is extremely unlikely due to the low probability of the initiating event as well as the explicit procedural guidance provided to the operators to limit RCS repressurization following an overcooling event.

REQUEST 9:

The B&W valve inlet fluid condition report identified a pressurization range 0-65 psi/sec was possible from extended HPI event which include steam, transition, and water conditions at the valve inlet. EPRI testing for transition and water condition, however, included pressurization rates of less then 3 psi/sec. This bounds the lower end of the pressurization range, but not the upper range. If the upper range of the pressurization rates occurs only for steam flow, then the 65 psi/sec rate would be bounded by steam testing conducted by EPRI. Demonstrate for Oconee 1, 2, and 3 that the upper range of the pressurization rates associated with extended HPI events only occurs for steam flow, otherwise, demonstrate the operability of the Dresser 31739A safety valve for transition and water flow with pressurizations rates of approximately 65 psi/sec.

RESPONSE 9:

Valve pressurization rate is not considered to be a significant factor in assuring operability of Oconee's Dresser safety relief valves. The original intention of varying this test parameter was to assure valve operability with maximum forces on the connected piping. Upon reaching its setpoint, the Dresser 31739A safety valve is an extremely fast acting valve - typically providing a combined "simmer" and "pop" time much less than one second. This opening time would correspond to system pressure rise of only 0 - 65 psig during the 0 - 65 psig/sec pressurization rate range as conservatively bounded for MSLB and FWLB events with extended HPI Operation (Reference 3). These pressurization rates were taken from previously performed B&W transient analyses, and measured rates were logged during the EPRI/CE valve tests. No correlation, however, was observed between the valve's ability to relieve and pressurization rate, as was observed for inlet temperature, where the valve did not relieve full design flow at 400°F.

Oconee has no loop seals, so loop seal test results are not directly applicable. However, it can be observed from the series of loop seal tests, (e. g., test numbers 1016, 1017, and 1021, and 1025 from Table 3.1.1c. (Reference 4), that valve performance was not markedly different for two widely different pressurization rates - approximately 2 psig/sec and approximately 300 psig/sec. The only discernable difference was a slightly longer valve opening time of 5.381 sec (combined "simmer" and "pop" times) for the lower pressurization rate in test number 1025 as compared to an opening time of 0.288 sec for the higher pressurization rate in test number 1021. Even less dependence is seen between similar test parameters for test numbers 1016 and 1017. In all loop seal tests, opening "pop" pressure was within safe limits.

Duke has performed scoping calculations which indicate the potential for water solid pressurization rates approaching 65 psig/sec for a scenario involving total loss of feedwater, which we consider to be more realistic than MSLB and FWLB cases with extended HPI. In this scenario, the pressurizer filled water solid, lifting the safety relief valve with nearly 600°F water. It is noted that operator action to manually open the PORV or unblock it if isolated would either prevent SRV operation or certainly minimize the rapid pressurization rate. This would make the valve transient more closely resemble EPRI test numbers 1110. Again, we consider the Loop Seal tests appropriate to show that there is no adverse SRV behavior simply due to higher pressurization rates. These high pressurization rate tests were originally conceived to assure valve operability with maximum focus on the connected piping.

REQUEST 10:

The submittal stated the PORV open setpoint was 2450 psia. The PORV close setpoint was not identified. EPRI testing of the Dresser PORV used in Oconee 1, 2, and 3 has the valve closing at pressures no greater than 2335 psia for steam conditions and 2360 psia for water conditions at the valve inlet. Identify the PORV close setpoint. If the close setpoint for the PORVs in Oconee 1, 2, and 3 is greater than 2360 psia, demonstrate the ability of the Dresser PORV to close at pressures greater than 2360 psia.

RESPONSE 10:

The closing setpoint is 2415 psia for the PORV's. Recent tests conducted at Wyle Labs on the Unit 3 PORV demonstrated valve operability at elevated pressure conditions. Multiple cycles were conducted with steam header pressures of approximately 2600 psig prior to opening and final pressures of 2400 psig after closing. The main disc opened and closed each time.

During one cycle at elevated pressures, the pilot disc failed to reseat tightly although it closed sufficiently to allow main disc closure. The cause was later determined to be loose metal particles that interfered with the pilot disc to pilot bushing guide clearances. The source of the particles appeared to be a rough machined surface just above the guided area on the new pilot bushing. The problem was corrected prior to returning the valve to Oconee. This appears to have been an isolated problem that was not associated with the elevated pressure test.

REQUEST 11:

NUREG-0737 Item II.D.1 required the plant-specific PORV control circuitry be qualified for design-basis transients and accidents. Please provide information which demonstrates this requirement has been fulfilled.

RESPONSE 11:

The PORV control circuit components are located in the cable room and are not subjected to any harsh environment. The control circuit components are fully qualified for the area in which they are located.

REQUEST 12:

For many of the steam tests with the short inlet configuration the Dresser 31739A valve failed to achieve rated lift and/or flow. Even with the reference ring settings, the valve failed to achieve rated lift and/or flow during three tests (Nos. 320, 322, and 1104a). Address this problem and discuss what measures will be taken in Oconee 1, 2, and 3 to assure the valves operate as designed.

RESPONSE 12:

All of the three short inlet configuration tests noted (320, 322, 1104a) used a middle ring setting of -40. The recommended Oconee setting of -50 provides a stronger lifting force and is expected to provide full lift for all conditions. Current middle ring settings of -40 at Oconee are not considered to be a problem because of these test results including full flow capability.

Test number 320 was the only one that provided less than rated steam flow. The decreased lift seen is a direct result of the excessive backpressure (866 psia) that was developed. The other two tests provided in excess of 100% rated flow with only partial lift. For both tests, the backpressures (609 psia and 600 psia) exceeded the Oconee worst case backpressure of 578 psia.

REQUEST 13:

The B&W valve inlet fluid condition report indicated that transition and liquid flow could exist for the PORV for extended HPI events (steam line and feedwater line breaks). The same flow conditions will also exist for the block valve. The EPRI block valve test program, however, did not test the block valve with fluid media other than steam. The Westinghouse Gate Valve Closure Testing Program did include water tests but the test program report did not provide specific test results. Since it is conceivable the EMOV would have to operate with liquid flows, discuss EMOV block valve operability with Oconee expected liquid flow conditions and provide specific test data.

RESPONSE 13:

The PWR utilities stated their position on additional block valve testing in the July 24, 1981 letter from Mr. R. C. Youngdahl to Mr. Harold Denton. That letter stated that no further block valve testing would be done beyond the full flow, full pressure steam testing performed at Marshall Steam Station. The reasons given included: 1) small break LOCA analyses have been performed for each plant and isolation of stuck open relief is not required for safe shutdown, block valve operability is therefore not a safety issue, 2) the probability of a stuck open relief valve is low, and 3) results of the Marshall tests have provided sufficient information to address valve operability.

As stated in the original submittal, the Oconee block valve has been modified to take advantage of the information learned from the EPRI tests. The primary modification was having the valve close on a stem travel limit rather than on torque so that full motor stall torque is available if difficulty is encountered while closing.

The final EPRI Westinghouse valve test (Reference 3) used a Limitorque SB-00-15 operator set to close on torque. The valve successfully closed with a torque switch setting less than maximum. Oconee uses the same operator-valve combination with the operator set on limit so that more operator closing force (i.e., full stall torque) is available.

In comparing valve operability on water versus steam, the two main factors in determining required thrust are the seating friction and the differential pressure (DP) across the valve disc. No specific data is available comparing seating friction in water versus steam. However, published data (based on proprietary information) from operator and valve manufacturers always uses a lower friction factor for water than is used for steam.

Considering differential pressure, water would present no higher DP than the steam test pressures. Block valve closure is a relatively slow motion, 6-10 seconds, that causes no water hammer effects. Maximum valve thrust requirements occur close to the full close position where flow is minimal and DP is highest.

Based on the operator modification, the above discussion, and the EPRI test results, Duke Power believes that operability for the PORV block has been demonstrated for all expected operating conditions.

REQUEST 14:

Block valve testing by EPRI was only performed in the horizontal position. The EPRI block valve test report indicated that B&W plants generally have the block valve installed in a vertical configuration. The submittal did not state the plant specific installation of the block valves in Oconee 1, 2, and 3. Identify the plant specific installation configuration of the block valves. If different than horizontal, discuss the effect of installation configuration on the operability of the Oconee valves.

RESPONSE 14:

The PORV block valves for Oconee 1, 2, and 3 are installed in vertical runs of pipe. The valves are fully operable in this installation configuration. An articulated stem to disc connection design insures that the disc is self aligning in any orientation.

The only installation restriction indicated by the manufacturer (Westinghouse) is that "valve installation with stem below horizontal is not permitted". The restriction is directed at operability of the Limtorque operator which is oriented to prevent lubricant from draining into the limit switch enclosure.

REQUEST 15:

Dresser Industries, the manufacturer of the Oconee PORV, wrote a letter to Metropolitan Edison Co. in March 1976 warning that the PORV block valve should be kept closed when reactor coolant system pressure is below 1000 psig to avoid damaging the PORV disk and seat by steam wirecutting. The EPRI program data indicates that the Dresser PORV was successfully tested on water at pressures in the 500-900 psig range. Steam testing at lower pressures was not performed. Each EPRI test sequence was initiated with a valve where disk and seat were in excellent conditon, which may not be representative of the condition of the Dresser PORV as routinely placed in service at Oconee. The recommendation made by Dresser that the PORV be isolated at pressures lower than 1000 psi would seem to preclude the use of the PORV for low temperatures overpressure protection of the reactor vessel. Explain whether the Dresser recommendation or a modification of it will be followed to prevent damage to the disk and seat from steam wirecutting or provide details of tests performed since the March 1976 letter that demonstrate that such precautions are unnecessary.

RESPONSE 15:

The Dresser recommendations were based on original design requirements which did not require PORV leak tightness in low pressure applications. Those recommendations are not associated with valve operability, therefore, Duke Power does not isolate the PORV unless indications (i.e., discharge RTD's Quench Tank temperature and level, and acoustic monitoring devices) show the valve is leaking. Duke has completed specific modifications (stronger main and pilot disc springs) that have improved the leak tight performance of these valves at low pressure conditions. These modifications have been completed on Units 1 and 2 and will be completed on Unit 3 by November 1985. In addition, the PORV disc and seats are normally maintained each refueling outage by lapping or replacement so they are in an acceptable condition for seat tightness.

REQUEST 16:

The submittal did not discuss the thermal hydraulic analysis of the safety/relief valve piping system. To allow for a complete evaluation of the methods used and the results obtained from the thermal hydraulic analysis, provide a discussion on the thermal hydraulic analysis that contains at least the following information:

(a) Evidence that the analysis was performed on the fluid transient cases producing the maximum loading on the safety/PORV piping system. The cases should bound all steam, steam to water, and water flow transient conditions for the safety and PORV valves.

(b) A detailed description of the methods used to perform this analysis. This includes a description of methods used to generate fluid pressures and momenta as a function of time and methods used to calculate the resulting fluid forces on the system. Identify the computer programs used for the analysis and how these programs were verified.

(c) Identification of important parameters used in the thermal hydraulic analysis and rationale for their selection. These include peak pressure and pressurization rate, valve opening time, and fluid conditions at valve opening.

(d) An explanation of the method used to treat valve resistances in the analysis. Report the valve flow rates that correspond to the resistances used. Because the ASME Code requires derating of the safety valves to 90% of actual flow capacity, the safety valve analysis should be based on flows equal to 111% of the valve flow rating, unless another flow rate can be justified. Provide information explaining how derating of the safety valves was handled and describe methods used to establish flow rates for the safety valves and PORVs in the analysis.

(e) A discussion of the sequence of opening of the safety valves that was used to produce worst case loading conditions.

(f) A sketch of the thermal hydraulic model showing the size and number of fluid control volumes.

(g) A copy of the thermal hydraulic analysis report as well as a copy of the EPRI report referenced in the submittal, Dynamic Loading on Pressurizer Safety and Relief Valve Discharge Line Due to Valve Actuation, September 22, 1982.

RESPONSE 16:

(a) Thermal hydraulic analysis for Oconee was performed for the following cases: lifting of the safety valves on steam, lifting of the PORV on steam, and lifting of the safety valves on water immediately after the pressurizer goes solid venting steam through the PORV. The surge line flow rate into the pressurizer for all cases was 220 lbm/sec. Comparison of this surgeline flow rate with those in Reference 6 for B&W units shows it to be conservative by a considerable margin. Oconee has two safety valves and one PORV. The specific transient cases include simultaneous lifting of both safety valves on steam without PORV operation, lifting of the PORV alone on steam, and simultaneous lifting of both safety valves on water following steam and water venting through the PORV. The cases analyzed for Oconee therefore bound all possible conditions leading to transient loading of the downstream pressurizer SRV and PORV piping.

(b) The thermal hydraulic analysis was performed using the computer code RELAP5/MOD1 (Reference 7). Fluid forces on the system were determined from the RELAP5 output using the computer program REPIPE, (Reference 8). The details of how each code operates to generate fluid pressures, moments, and the resulting forces may be found in these references. Qualification of RELAP5 to preform the required calculation was part of the EPRI program, and the results are reported in Reference 9. REPIPE is a proprietary product of Control Data Corporation and has been in general use for computing forces as a result of fluid transients for several years. It has been verified by Control Data Corporation against hand calculations.

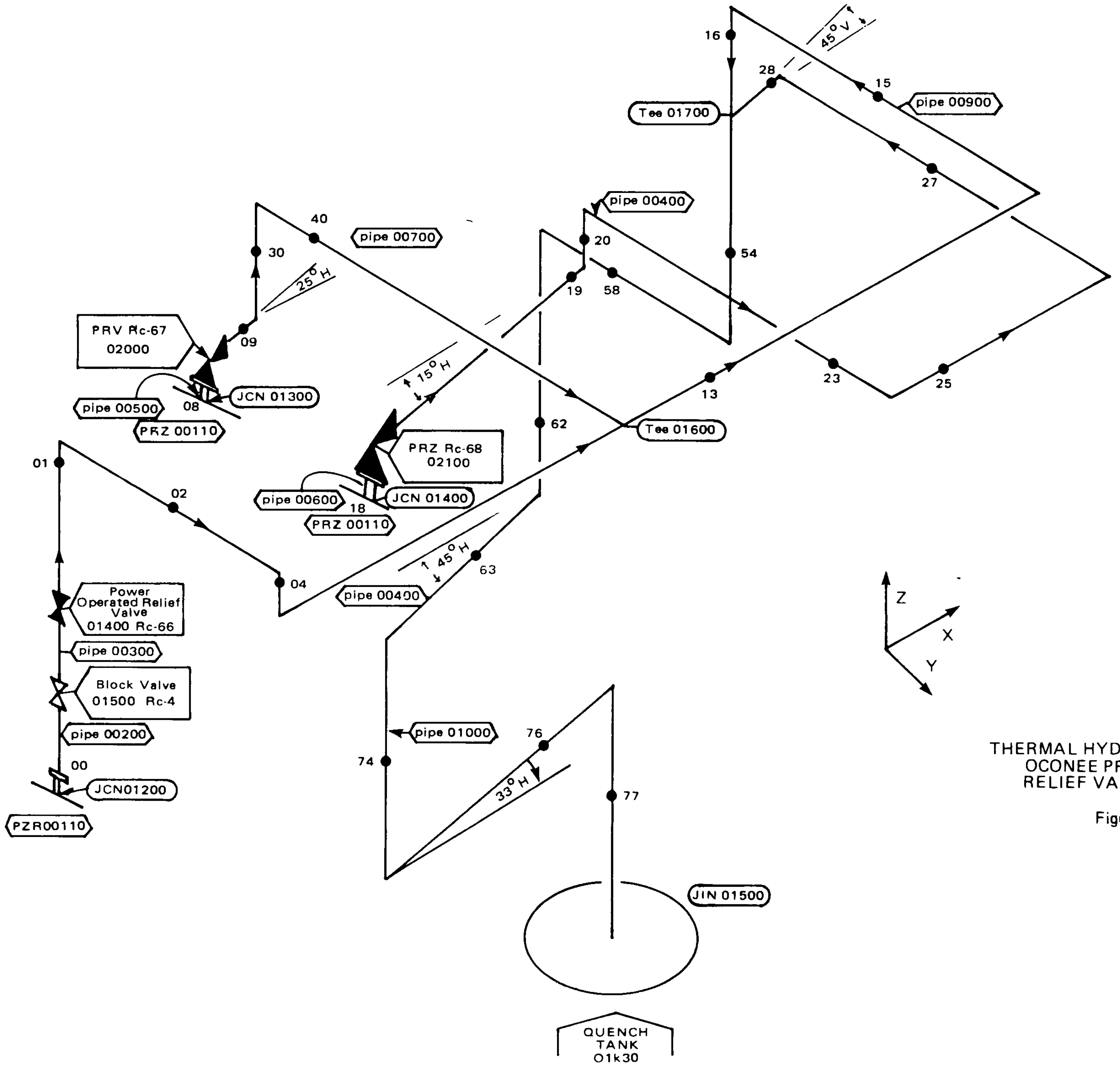
(c) Since action of the pressurizer pressure relief system occurs in response to an insurge into the pressurizer as a result of a temperature increase in the primary coolant, during our analysis the flow rate through the pressurizer surge line was considered to be the most important parameter. Peak pressure and pressurization rate are a consequence of the insurge rate. As noted in response to part (a) above, this insurge rate was selected conservatively. Valve opening time of 15 milliseconds was used for the PORV. As shown by EPRI test data and station performance information, these opening times are conservatively fast compared to actual valve performance. Fluid conditions at valve opening are as noted in the response to part (a), above.

(d) Each valve was treated as a simple adjustable orifice, with the maximum opening area corresponding to drawing dimensions or other vendor information. The options selected in RELAP5 include the abrupt area change model and the choking model at the valve seat. The orifice area was assumed to increase linearly during valve opening time. The approximate maximum steam flow rates which resulted from these assumptions in the analysis were 100 lbm/sec for each safety valve and 30 lbm/sec for the PORV, and the maximum water flow rates which resulted from these assumption were 240 lbm/sec for each safety valve and 70 lbm/sec for the PORV. The rated steam flow rate for the safety valves is 82.7 lbm/sec; therefore, the flow rate selected for the analysis is 18% higher than rated. The experimentally determined flow rate for water relief through the safety valves is approximately 240 lbm/sec. (Reference 10, test no. 1107). The flow rates for the PORV were found to be of no consequence to the analysis because the longer stroke time of the PORV precludes the development of significant transient forces in the downstream piping during opening of the PORV.

(e) The two safety valves were assumed to open simultaneously for both the water flow and the steam flow cases. This produced the maximum change in flow velocity downstream, and therefore the maximum loading on the piping system.

(f) In order to satisfy the Courant limit for the time step size selected (0.01 millisecond), piping volumes were selected to be two feet long or less. The requested sketch is attached as Figure 1.

(g) The thermal hydraulic analysis is documented in Duke Power Company calculation OSC 1692, dated August 24, 1982, which is available for inspection at our Charlotte office. There is no formal report of the thermal hydraulic analysis available for distribution. We are unable to locate the report requested in the NRC question, however, we believe it refers to a preliminary version of Reference 9. EPRI reports are available from the Research Reports Center, P. O. 50490, Palo Alto, CA 94303.



THERMAL HYDRAULIC MODEL
OCONEE PRESSURIZER
RELIEF VALVE SYSTEM

Figure 1

REQUEST 17:

The submittal indicated that a structural analysis of the safety/PORV valve piping system has been conducted, but does not present details of the analysis. To allow for a complete evaluation of the methods used and results obtained from the structural analysis, please provide reports containing at least the following information:

a. Identify the computer programs used for the analysis and how these programs were verified.

b. An identification of the load combinations performed in the analysis together with the allowable stress limits for each load combination. Differentiate between load combinations used in the piping upstream and downstream of the valve. Explain the mathematical methods used to perform the load combinations. It is not clear from the submittal whether the 1967 USAS B31.1 Code or the 1980 ASME Code was used to define acceptable piping stress levels. Identify the piping stress criteria used in the analysis. If the ASME Code was used, state which class was used.

c. Provide a table comparing the calculated stress with the allowable stress for the most highly loaded pipes.

d. An evaluation of the results of the structural analysis. The submittal stated an evaluation of the piping, in accordance with the 1967 USAS B31.1 code with loading conditions that include the new transients, found piping stresses slightly exceeding B31.1 allowable stresses. It also stated modifications are planned in order to reduce the piping system stresses. Identify the overstressed locations and describe the planned modifications.

e. A sketch of the structural model showing lumped mass locations, pipe sizes, and application points of fluid forces.

f. A copy of the structural analysis report as well as a copy of the EPRI report referenced in the submittal, Determination of As-Tested Bending Moments Acting on Test Valve Discharge Flanges.

RESPONSE 17:

(a) The primary analysis program used for the analysis of the Pressurizer Relief Valve Discharge System was SUPERPIPE, a proprietary product of Impell Corporation.

SUPERPIPE has been thoroughly verified for a comprehensive set of sample problems. This has included benchmarking by EDS against the ASME Sample Problems 1 and 6 contained in ASME publication "Pressure Vessel and Piping 1972, Computer Program Verification," and against a Class 1 sample problem contained in ASME publication "Sample Analysis of a Piping System, Class 1 Nuclear," 1972. Extensive benchmarking has also been performed by EDS against the programs, PISOL1A and PISOL3A which are well recognized and utilized throughout the industry. Additionally, the program has been benchmarked by EDS against the programs such as NUPIPE, ADLPIPE, PIPESD and EDSGAP. SUPERPIPE has been used on a number of domestic and foreign plants. These include South Texas, McGuire 1, and San Onofre 1 and 2 (United States); Tihange 2 (Belgium); Kernkraftwerk Kruemmel, and Kernkraftwerk Pillipsburg (Germany); Kernkraftwerk Iran (Iran); Almaraz, Cofrentes and Valdecaballeros (Spain); and, Leibstadt (Switzerland).

(b) Load Cases Considered:

(1) Gravity (GRAV)
(2) Static Internal Pressure P = 700 PSI (PRESS)
(3) Thermal, T_{hot} = 500° F (THRM)
(4) Operational Basis Earthquake (OBE)
(5) Safety Relief Valve Discharge, Valves Open: 1, 2, 3, RC-67&68 (SRV)
(6) Power Operated Relief Valve and Safety Relief Valve Discharge, Valves Open: 1, 2, 3, RC-67&68, 1, 2,3RC-04 (WATR)
(7) Thermal Anchor Motion: Pressurizer Thermal Growth (TAM)

Loading Combinations

(1) Normal Operating Conditions:
Primary: GRAV + PRESS
Secondary: THRM + TAM
Primary + Secondary: GRAV + PRESS + THEM + TAM

(2) Upset Conditions:
UPSET: GRAV + PRESS + OBE
UPS2: GRAV + PRESS + ABSOLUTE ENVELOPE (SRV & WATR)

(3) Faulted Conditions:
Faulted: GRAV + PRESS + 2XOBE

Identical loading combination used upstream and downstream of all valves.

Analysis Code of Record

ANSI 1967 USAS B31.1 Code

ANSI 1969 USAS B31.7 Code

(c) CALCULATED MAXIMUM STRESSES VS ALLOWABLE STRESSES

UNITS 1 & 2

LOAD CASE	LOCATION (NODE)	CALCULATED STRESS (PSI)	ALLOWABLE (PSI)	LOAD COMBINATION
PRIMARY	85	11,113	14,550	GRAV + PRESS
SECONDARY	35B	28,549[1]	27,075	THRM + TAM
PRIMARY & SECONDARY	35B	34,176	41,625	GRAV + PRESS + THRM + TAM
UPSET	85	13,037	17,460	GRAV + PRESS + OBE
UPS2	85	20,925	21,180	GRAV + PRESS + ENVELOPE (SRV + WATR)
FAULTED	85	14,961	18,200	GRAV + PRESS + 2XOBE

NOTE (1): The Code permits qualification of the Primary and Secondary Load Case in lieu of the Secndary Load Case when the calculated Secondary Stress exceeds the Secondary Allowable Value.

CALCULATED MAXIMUM STRESSES VS ALLOWABLE STRESS

UNIT 3

LOAD CASE	LOCATION (NODE)	CALCULATED STRESS (PSI)	ALLOWABLE (PSI)	LOAD COMBINATION
PRIMARY	95B	10,243	14,550	GRAV + PRESS
SECONDARY	35B	27,021	27,075	THRM + TAM
PRIMARY & SECONDARY	35B	37,264	41,625	GRAV + PRESS + THRM + TAM
UPSET	85	11,377	17,460	GRAV + PRESS + OBE
UPS2	85	19,574	21,180	GRAV + PRESS + ENVELOPE (SRV & WATR)
FAULTED	85	15,656	18,200	GRAV + PRESS + 2XOBE

Allowable Explanation

LOAD CASE	ALLOWABLE EXPLANATION	ALLOWABLE VALUE	REF. CODE
PRIMARY	S_h @ 500° F	14,550 PSI	USAS B31.1 (1967)
SECONDARY	S_a @ 500° F	27,075 PSI	USAS B31.1 (1967)
PRIMARY & SECONDARY	$S_h + S_a$ @ 500° F	41,625 PSI	USAS B31.1 (1967)
UPSET	$1.2S_h$ @ 500° F	17,460 PSI	USAS B31.1 (1967)
UPS2	$1.2S_h$ @ 150° F	21,180 PSI	USAS B31.1 (1967)
FAULTED	S_y @ 500° F	18,200 PSI	USAS B31.7 (1969)

NOTE (1)

$$S_a = F\ (1.25\ S_c + .25\ S_h)$$

Where F = 1 For Operating Cycles < 7,000

(d) Results of Structural Analysis

The analysis of the Pressurizer Relief Valve System for Oconee Nuclear Station was divided into two parts. Part One included the analysis of the Unit 1 & 2 systems, Part Two was the analysis of the Unit 3 system. The reason for the separate analyses was due to geometrical differences in the system layouts and differences between support schemes. The results of the analyses indicated that support modifications were needed so that piping stresses would meet code allowables. The Unit 1 & 2 systems required twelve support modifications. The Unit 3 system required seventeen support modifications. The modifications included the installation of several new supports per unit, the changing of variable and constant spring supports to rigid supports, the relocation of several rigid supports, and the replacement of welded pipe attachments. All modifications to the Pressurizer Relief Valve Discharge System are now complete and installed at Oconee Nuclear Station Units 1, 2, & 3. As a result of these modifications, the current piping stresses are below code allowables as shown in Part (c) above. The preliminary computer analyses defining the slightly overstressed piping locations prior to modifications were not retained since the modifications are now completed. However, the results of the preliminary analysis were reviewed and the piping system was determined to be operable for the new loading condition, prior to support modifications.

(e) The 'As-Built' analysis isometrics of the Units 1 & 3 Pressurizer Relief Valve systems are attached as Figures 2 and 3. The Unit 1 isometric is applicable to both Units 1 & 2. The computer program 'SUPERPIPE' automatically generates lumped mass points. Masses are lumped at points of discontinuity and at a maximum of "L" in straight pipe, as defined below:

PIPE SIZE	SCHEDULE	"L" (INCHES)
12"	STD	88
8"	40	75
6"	40	66
4"	40	55

Dynamic transient blowdown forces are applied at the tangent points of elbows in the direction of the straight pipe axis.

(F) The structural analysis of the Pressurizer Relief Valve Discharge System is located in calculation No.(s) OSC 1313-06 (Units 1 & 2) and OSC 1351-06 (Unit 3). Copies of these calculations are not included in this submittal due to the bulk of the material. However, these calculations are on file at Duke Power Company offices in Charlotte, North Carolina and readily available to the Nuclear Regulatory Commission.

Attached is a copy of the EPRI Report, "Determination of As-Tested Bending Moments Acting on Test Valve Discharge Flanges."

FIGURE 2

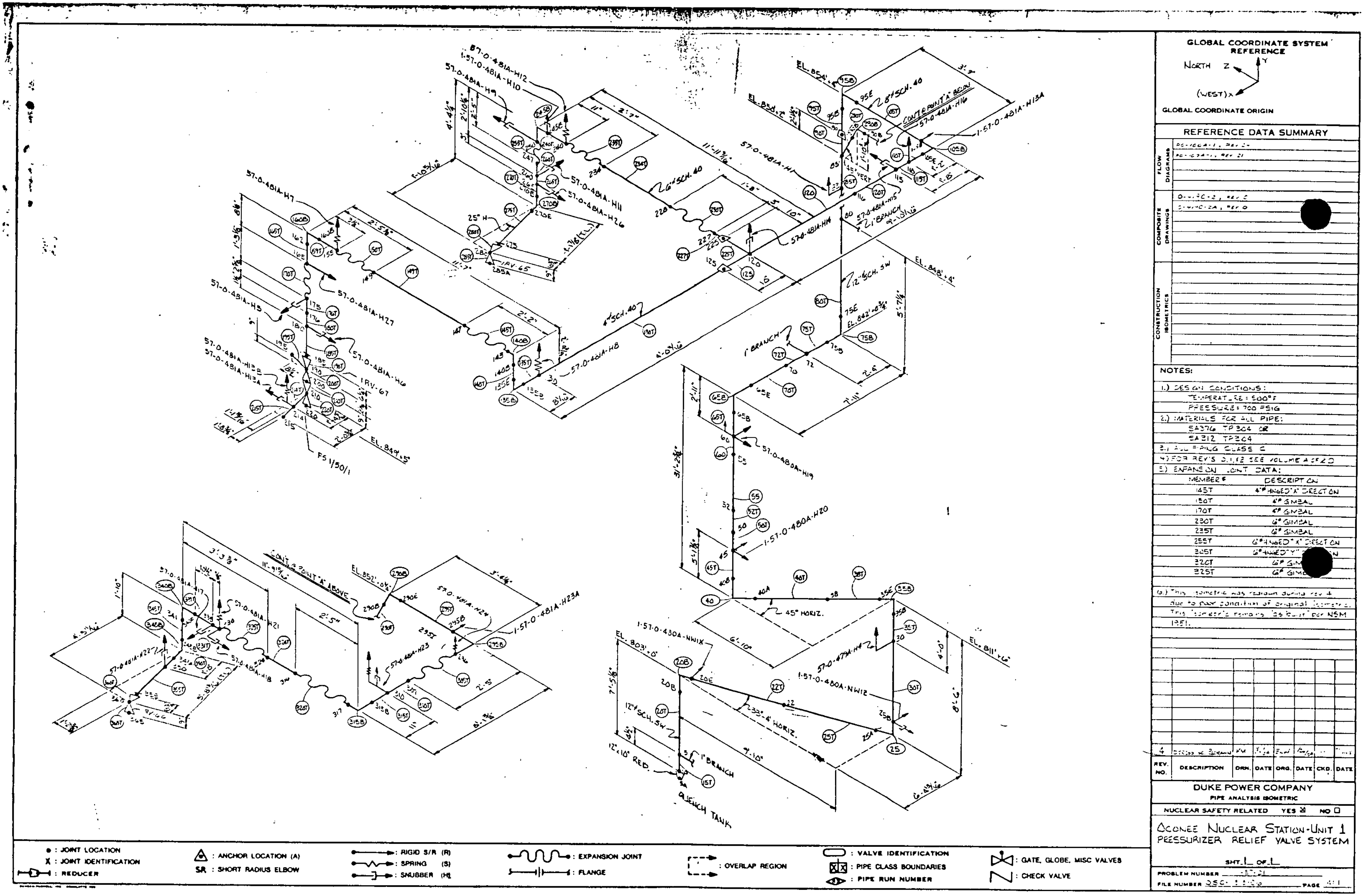
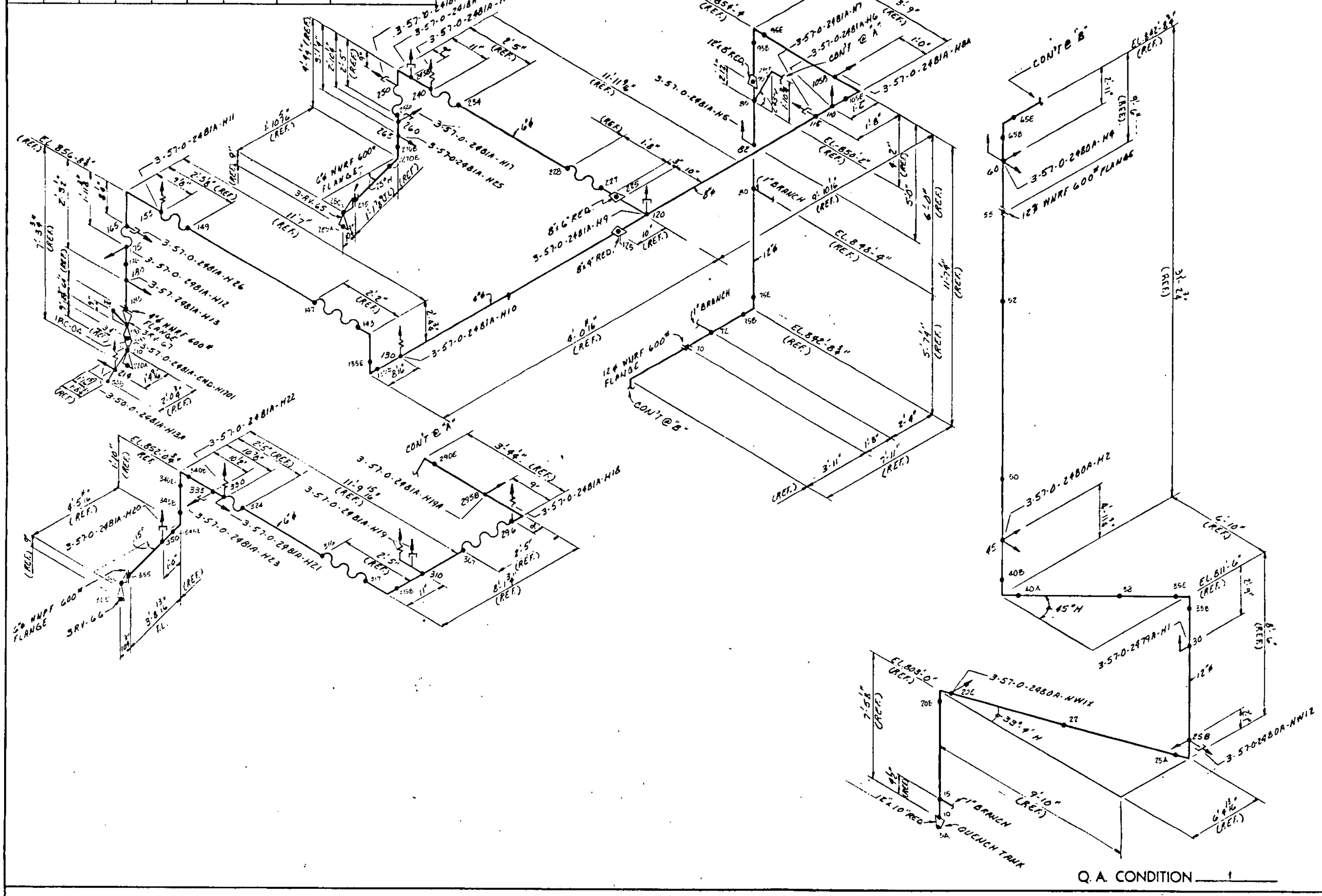

GLOBAL COORDINATE SYSTEM REFERENCE
NORTH Z
(WEST) X
GLOBAL COORDINATE ORIGIN
REFERENCE DATA SUMMARY
FLOW DIAGRAMS
COMPOSITE DRAWINGS
CONSTRUCTION ISOMETRICS
NOTES:
1.) DESIGN CONDITIONS:
TEMPERATURE: 500°F
PRESSURE: 700 PSIG
2.) MATERIALS FOR ALL PIPE:
SA376 TP304 OR
SA312 TP304
5) EXPANSION JOINT DATA:
MEMBER # DESCRIPTION
145T
150T 6" GIMBAL
170T 6" GIMBAL
230T 6" GIMBAL
235T 6" GIMBAL
REV. NO. DESCRIPTION DRN. DATE ORG. DATE CKD. DATE
DUKE POWER COMPANY
PIPE ANALYSIS ISOMETRIC
NUCLEAR SAFETY RELATED YES NO
OCONEE NUCLEAR STATION-UNIT 1
PRESSURIZER RELIEF VALVE SYSTEM
SHT. 1 OF 1
PROBLEM NUMBER
FILE NUMBER
PAGE
JOINT LOCATION
JOINT IDENTIFICATION
REDUCER
ANCHOR LOCATION (A)
SHORT RADIUS ELBOW
RIGID S/R (R)
SPRING (S)
SNUBBER (H)
EXPANSION JOINT
FLANGE
OVERLAP REGION
VALVE IDENTIFICATION
PIPE CLASS BOUNDARIES
PIPE RUN NUMBER
GATE, GLOBE, MISC VALVES
CHECK VALVE
QUENCH TANK
CONT'D POINT "A" BELOW
CONT'D POINT "A" ABOVE
EL. 854'-6"
EL. 852'-0 1/4"
EL. 848'-4"
EL. 849'-5"
EL. 811'-6"
EL. 803'-0"
12"x10" RED.
12" SCH. SW
4" SCH. 40
6" SCH. 40
8" SCH. 40
1" BRANCH
45° HORIZ.
1RV-65
1RV-67

FIGURE 3

TABLE 1								
SYS.	LINE	CLASS	DESIGN		PIPE SPEC.	MATERIAL		PIPE SCHEDULE
			TEMP. °F	PRESS PSIG		PIPE	INSULATION	
57	1	C	500	700	601.3	SA 376 TP 304	N/A	4", 6" & 8" SCH. 40 12" SCH. 40S



Q.A. CONDITION 1

DWG. NO. 0-3RB-357001-01 REV. 0

GLOBAL COORDINATE SYSTEM REFERENCE

GLOBAL COORDINATE ORIGIN

REFERENCE DRAWINGS

CIVIL DRAWINGS		
PIPING DRAWINGS	0-2491C-2	REV.
	0-2491C-3	REV. 0
FLOW DIAGRAMS	PO 100A-1	REV. 23
	PO-107A-1	REV. 20

NOTES:

1. This drawing shows the location of pipe supports relative to the piping system and should be used for pipe support erection only. All other information and all elevations are for reference and piping analysis use only.
2. The support/restraint calculation number(s) corresponding to this problem is ______.
3. The piping analysis calculation number(s) corresponding to this problem is OSC-1351-06.
4. Tolerances on S/R locations shall be in accordance with spec. ______, unless noted otherwise.
5. All piping shown on this (set of) isometric drawing(s) is located in, and all S/R's are attached to the Reactor Building ______, unless noted otherwise.
6. For the applicable QA Condition for eac S/R, see the individual hanger sketch.

REV. NO.	DESCRIPTION	DRN / DATE	PAG CK / DATE	SRG CK / DATE	APPR / DATE
0	ISSUED				

DUKE POWER COMPANY
OCONEE NUCLEAR STATION

REACTOR BUILDING UNIT 3
PIPING ANALYSIS & S/R ISOMETRIC
SYSTEM 57 PROBLEM 3-57-01
PRESSURIZER RELIEF VALVE SYSTEM

DRAWN ______ DATE ______ MTR INSP ______ WAIVED ______ DATE ______
PAG CK ______ DATE ______ RELEC INSP ______ WAIVED ______ DATE ______
SRG CK ______ DATE ______ APPR ______ DATE ______

DWG NO. 0-3RB-357001-01 REV. 0

NEW PIPING	ANCHOR LOCATION	RIGID S/R	EXPANSION JOINT	DCP LOCATION	GATE, GLOBE, MISC VALVES
EXISTING PIPING	REDUCER	SPRING	FLANGE	X DCP IDENTIFICATION	CHECK VALVE
		SNUBBER		LINE NUMBERS	

SECTION 3

DETERMINATION OF AS-TESTED BENDING MOMENTS ACTING ON TEST VALVE DISCHARGE FLANGES

3.1 BENDING MOMENT DURING VALVE OPENING AND CLOSING

One of the criteria which must be evaluated for demonstration of safety valve operability is the effect of discharge piping loadings on the mechanical stroking ability of safety valve internals. The loads imposed on the safety valves during this test program had no measureable effect on valve operability. The maximum recorded bending moment acting on the safety valve discharge flange is reported for each valve test in Table 3-1. These values are as-tested bending moments and do not constitute a maximum allowable moment above which the valve will no longer function.

A schematic of the test valve and discharge piping system is shown in Figure 3-1.

The bending moments reported in Table 3-1 are calculated by multiplying the vertical force at the second discharge elbow times the horizontal distance to the valve discharge flange. In Figure 3-1, the moment equation is expressed as M = (WE 32 + 33Y)L. The expression (WE 32 + 33Y) reflects the vertical summation of two load cell readings at the second elbow. The vertical support at this elbow is shown in Figure 3-2 and consists of an A-frame with a load cell in each leg of the A-frame. This vertical load is recorded continuously throughout each test. The load cell data, along with valve stem position, are presented in Figure 3- through Figure 3- . The stem positionplots are used to determine the time at which the valve opens and closes.

The bending moments listed in Table 3-1 are based on the value of WE 32 + 33Y just before the valve opens and just after the valve closes. The loads recorded at the second elbow support at these times consist of dead weight, initial bolt up, and thermal expansion loads. All of these loads are transmitted back to the test valve and develop bending moments at the valve discharge flange. These bending moments act about the horizontal, out of plane Z axis in Figure 3-1. This direction of bending is as severe or more severe than any other plane of bending so that these allowable moment values are recommended to be considered the as-tested limit for all moment directions.

An inspection of moment values in Table 3-1 indicates that recorded moments are generally higher for test series 900 through 1400 than they are for the earlier test series. In the earlier series, the second elbow vertical support contained a snubber in each leg of the A-frame. Snubbers were installed to minimize the effects of thermal expansion due to discharge piping heatup when the safety valves discharge. On some tests, the snubbers would lock and then relax slowly resulting in high thermal expansion loads. In other tests, the snubbers would relax more quickly resulting in lower thermal expansion loads. This snubber behavior is the reason for the wide range of moment values in several of the earlier test series.

Prior to the 900 series tests, the snubbers were replaced by rigid links. The rigid links resist discharge piping thermal expansion thereby imposing higher loads on the safety valve during the 900 and subsequent test series.

3.2 BENDING MOMENT DURING VALVE TEST TRANSIENT

An effort has been made to determine the moments imposed on the test valve while the valve is open and flowing. This effort has included both periods of valve instability and valve steady-state open flow. When the valve is open, hydrodynamic forces are acting on the valve and discharge piping supports. When these forces are resisted at the second elbow vertical support, only a portion of the load is transmitted back to the valve. Sufficient test data are not available to separate ~~aparate~~ out these portions of load, so the second elbow vertical forces are not applicable for the dynamic moment calculation.

The test valve support station data has also been evaluated to determine the dynamic moment acting on the safety valves. As shown in Figure 3-1, the test valve is supported in the horizontal direction by two parallel support links located just below the test valve inlet flange. There is a load cell in each of the support link load paths. These load cells, labled WE 28 and WE 29, resist horizontal forces at the valve station and also form a moment resisting couple which limits valve body rotation in order to protect the inlet piping. The valve station support is shown in detail in Figure 3-3 and Figure 3-4. Test data for WE 28 and WE 29 has been reviewed and indicates that large moments are developed at the valve support station. At the same time for any specific test, however, the test data WE 32 + 33Y indicates that the loads in the discharge system are quite small. The apparent reason for this difference is that a large portion of the bending loads recorded at the valve station are due to the inlet piping. Moments in the inlet piping are resisted at the valve station and are not transmitted through the valve body. This test data is therefore not applicable for the determination of test valve bending moments.

For these reasons, the bending moments on the test valve during valve actuation and steady-state flow have not been determined. The moment values listed in Table 3-1 reflect only the moment just prior to valve opening and just after valve closing.

TABLE 3-1

TEST	VALVE	(in-lbs) OPENING MOMENT	(in-lbs) CLOSING MOMENT
201	Dresser ~~6x8~~ 31709NA	55,000.	137,500.
302	Dresser ~~2-1/2x6~~ 31735A	80,113.	94,250.
304		75,400.	94,250.
306		75,400.	84,825.
308		80,113.	98,963.
310		84,825.	103,675.
312		75,400.	98,963.
314		75,400.	94,250.
316		84,825.	89,538.
318		84,825.	94,250.
320		84,825.	103,675.
322		80,113.	103,675.
324		75,400.	89,538.
326		98,963.	84,825.
328		65,975.	89,538.
403	Crosby ~~3x6~~ 3K6	N/A	142,500.
406		85,500.	123,500.
408		85,500.	123,500.
411		85,500.	114,000.
415		0.	28,500.
416		19,000.	9,500.
419		19,000.	9,500.
422		19,000.	19,000.
425		14,250.	9,500.
428		0.	2,850.
431		32,300.	14,250.
435		24,700.	N/A
438		7,600.	19,000.
441		161,500.	152,000.
442		133,000.	104,500.
506		41,300.	59,000.
508		5,900.	5,900.

TABLE 3-1 (Continued)

TEST	VALVE	(in-lbs) OPENING MOMENT	(in-lbs) CLOSING MOMENT
516	Crosby ~~3x6~~ 3K6	41,300.	56,050.
517		41,300.	59,000.
525		70,800.	70,800.
526		53,100.	147,500.
529		64,900.	64,900.
532		59,000.	59,000.
535		47,200.	59,000.
536		47,200.	59,000.
537		53,100.	64,900.
603	Dresser ~~6x8~~ 31709NA	68,250.	91,000.
606		81,900.	91,000.
611		68,250.	95,550.
614		86,450.	100,100.
615		68,250.	100,100.
618		63,700.	91,000.
620		77,350.	95,550.
623		100,100.	77,350.
625		91,000.	N/A
628		81,900.	81,900.
630		100,100.	77,350.
703	Target Rock 69C	51,750.	143,750.
706		57,500.	230,000.
709		57,500.	258,750.
712		80,500.	N/A
714		54,625.	201,250.
717		58,650.	230,000.
719		56,350.	74,750.
722		52,900.	54,625.
723		53,475.	54,625.
803	Crosby/Framatome 6M6	59,750.	65,725.
806		59,750.	101,575.
808		59,750.	134,438.

TABLE 3-1 (Continued)

TEST	VALVE	(in-lbs) OPENING MOMENT	(in-lbs) CLOSING MOMENT
811	Crosby /Framatome 6M6	59,750.	179,250.
814		59,750.	250,950.
817		47,800.	268,875.
819		56,763.	155,350.
822		59,750.	239,000.
825		55,568.	N/A
828		47,800.	256,925.
831		47,800.	47,800.
903	Crosby 6M6	215,100.	35,850.
906		256,925.	53,775.
908		298,750.	29,875.
910		209,125.	71,700.
913		239,000.	59,750.
914		203,150.	83,650.
917		227,050.	71,700.
920		215,100.	101,575.
923		179,250.	89,625.
926		89,625.	95,650.
929		179,250.	89,625.
931		161,325.	N/A
932		107,550.	17,925.
1003	Dresser ~~2-1/2x6~~ 31739A	145,625	52,425.
1005		163,100.	99,025.
1008		49,513.	64,075.
1011		241,738.	75,725.
1012		64,075.	69,900.
1016		186,400.	52,425.
1017		186,400.	145,625.
1018		0.	49,513.
1021		157,275.	52,425.
1025		157,275.	17,475.
1027		131,063	N/A

TABLE 3-1 (Continued)

TEST	VALVE	(in-lbs) OPENING MOMENT	(in-lbs) CLOSING MOMENT
1030	Dresser ~~2-1/2x6~~ 31739 A	87,375.	58,250.
1104		230,913.	56,550.
1107		226,200.	9,425.
1110		169,650.	4,713
1112		158,340.	18,850.
1114		84,825.	N/A
1202	Crosby ~~6x8~~ 6N8	336,700.	527,800.
1203		245,700.	682,500.
1205		254,800.	627,900.
1207		300,300.	655,200.
1208		427,700.	473,200.
1209		291,200.	518,700.
1211		354,900.	591,500.
1213		364,000.	518,700.
1305	Dresser ~~6x8~~ 31709 NA	163,800.	200,200.
1308		163,800.	473,200.
1311		427,700.	445,900.
1406	Crosby 6M6	35,850.	286,800.
1411		107,550.	239,000.
1415		59,750.	268,875.
1419		23,900.	256,925.

FIGURE 3-1

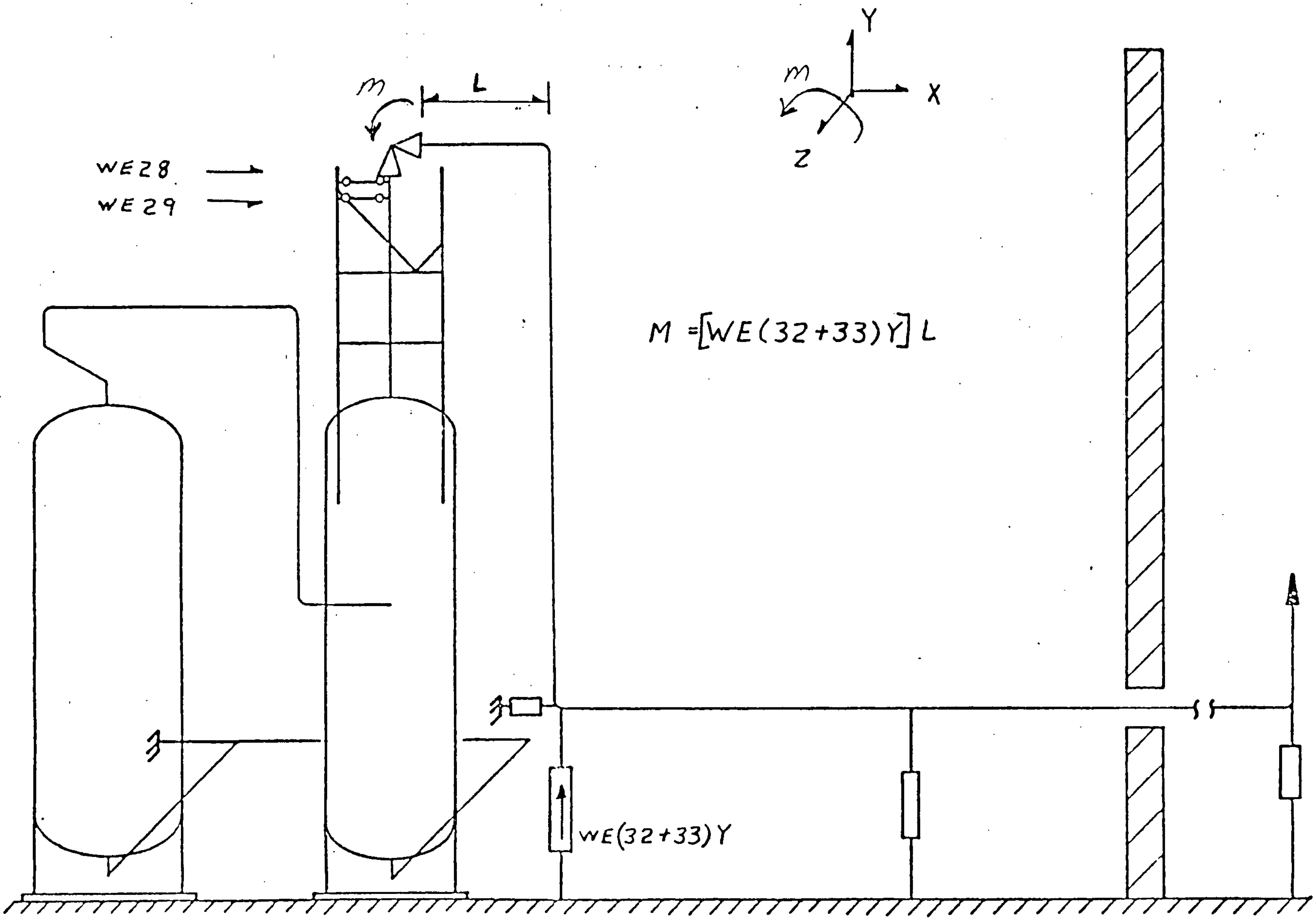
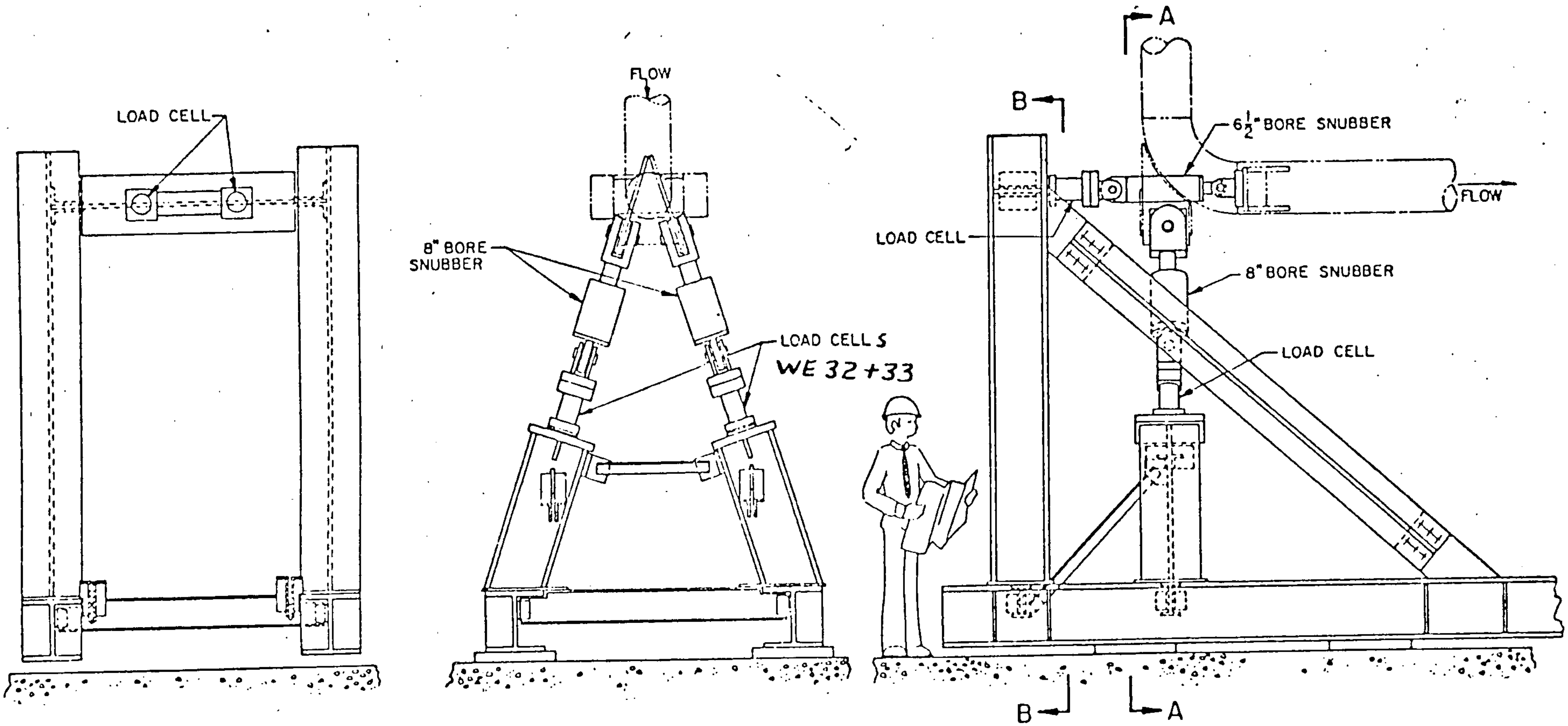
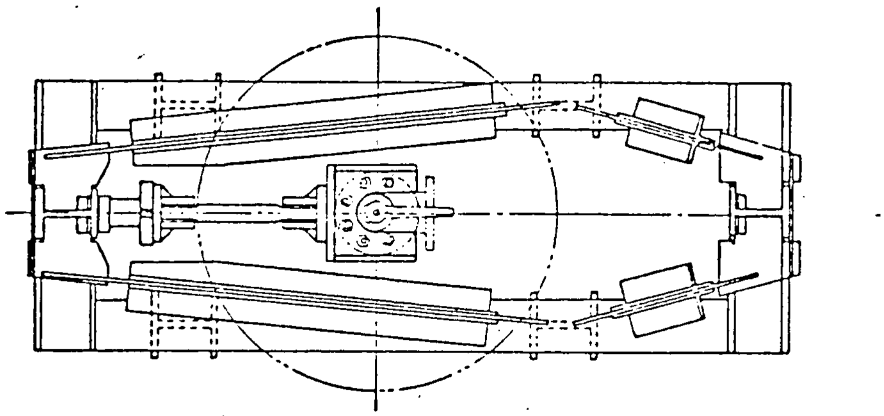
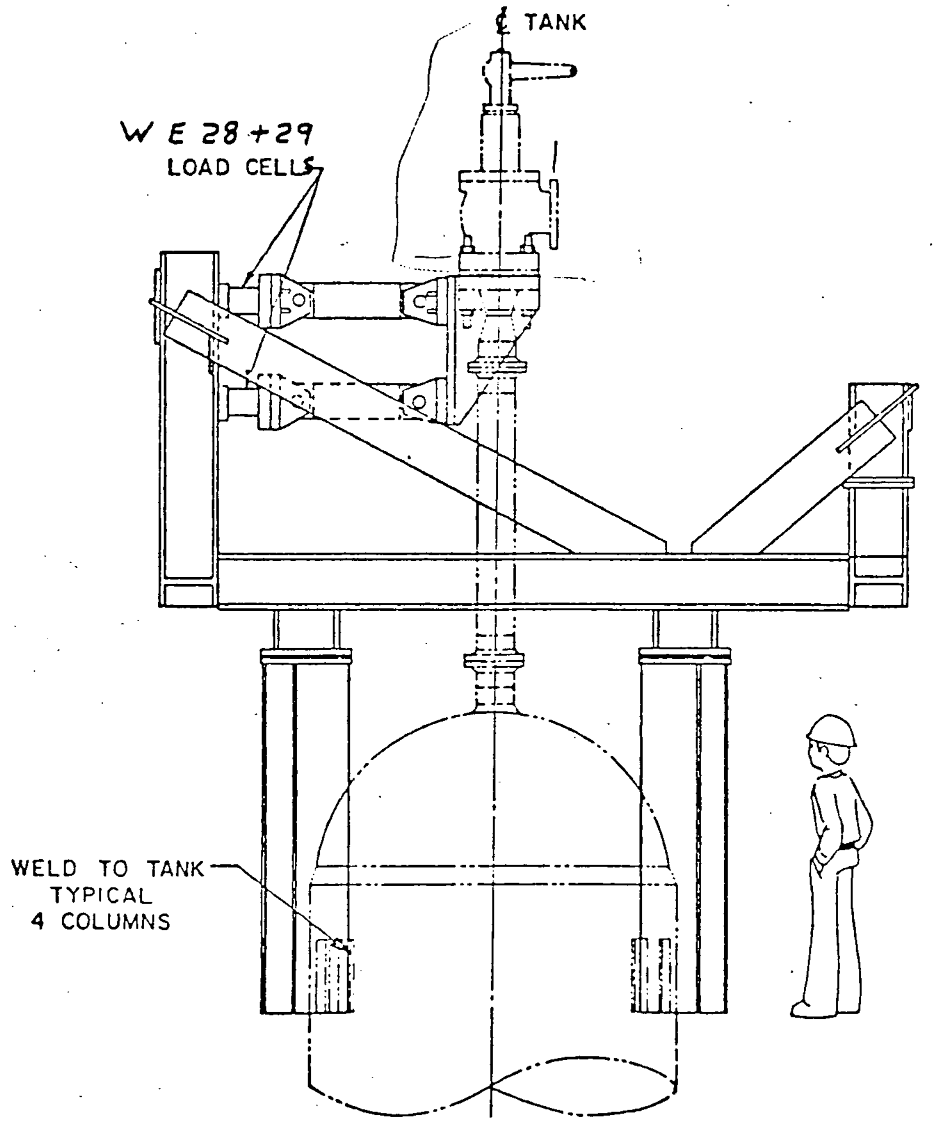


FIGURE 3-2



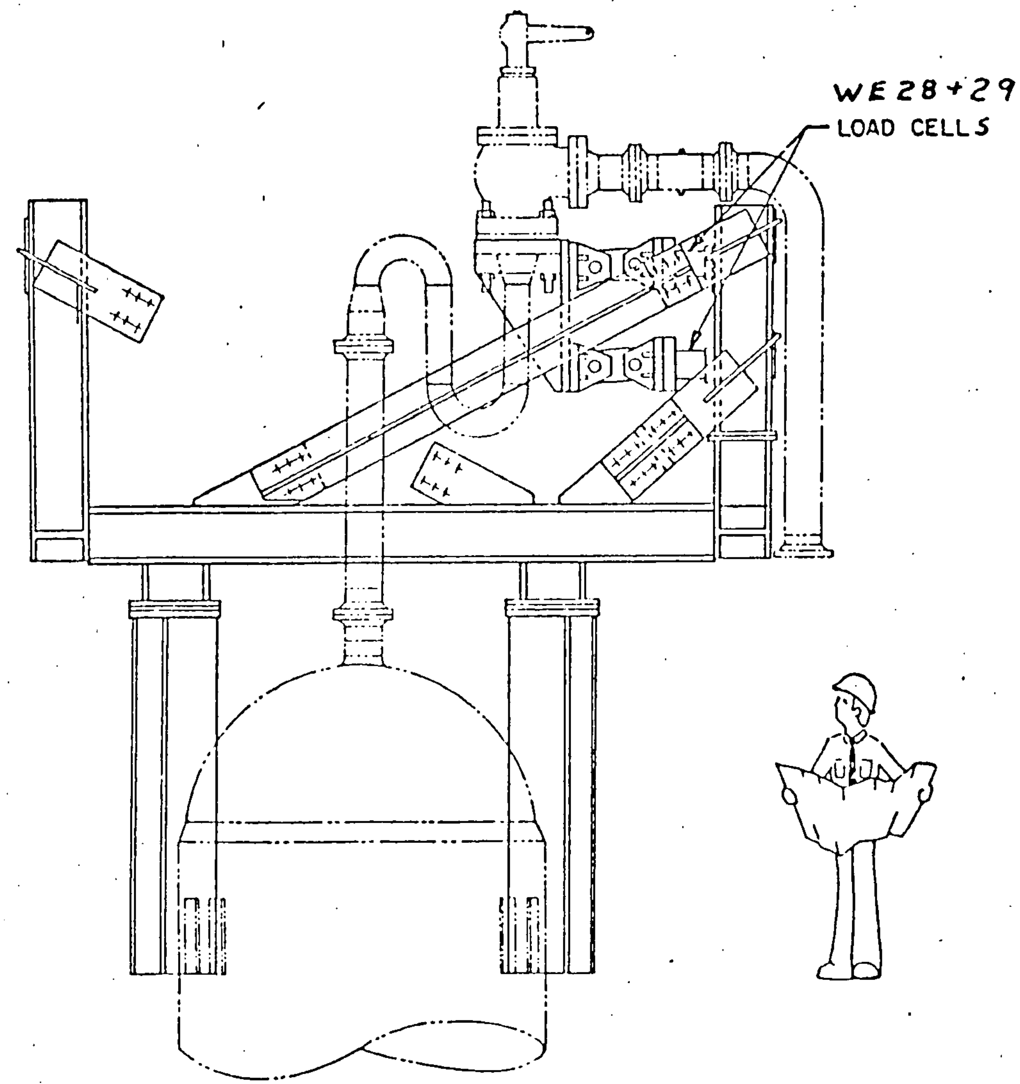
SECTION B-B SECTION A-A SECOND ELBOW PIPE SUPPORT ASS'Y





UPPER TEST STAND ASS'Y / SAFETY VALVE

FIGURE 3-3



UPPER TEST STAND ASS'Y /
SAFETY VALVE WITH LOOP SEAL

FIGURE 3-4

DATE :3/9.‿2
TIME :23/54/51

FIGURE 3-5

POWER

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