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

HAL B. TUCKER
VICE PRESIDENT
NUCLEAR PRODUCTION

TELEPHONE
(704) 373-4531

June 12, 1985

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

Attention: Ms. E. G. Adensam, Chief
Licensing Branch No. 4

Re: McGuire Nuclear Station
Docket Nos. 50-369 and 50-370

Dear Mr. Denton:

Ms. E. G. Adensam's letter of March 11, 1985 transmitted a request for additional information regarding performance testing of relief and safety valves for McGuire Nuclear Station.

The attached response addresses the specific concerns of the staff regarding the relief and safety valves.

Very truly yours,

H. B. Tucker /JBD

Hal B. Tucker

JBD/glb

Attachment

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

Mr. Darl Hood, Project Manager
Division of Project Management
Office of Nuclear Regulatory Commission
Washington, D. C. 20555

NRC Resident Inspector
McGuire Nuclear Station

A046
1/1

REQUEST FOR ADDITIONAL INFORMATION

REGARDING NUREG-0737 ITEM II.D.1

FOR

MCGUIRE

UNITS 1 AND 2

DOCKET NOS.: 50-369 AND 50-370

QUESTIONS RELATED TO THE SELECTION OF TRANSIENTS AND VALVE INLET AND DOWNSTREAM CONDITIONS

Question 1

The Westinghouse inlet fluid conditions report (Ref. 1) identifies McGuire 1 and 2 as one of the plants not being covered by the report with respect to the cold overpressurization event. The McGuire 1 and 2 submittals (Refs. 2, 3 and 4) however, state that review of the cold overpressure fluid conditions are represented by the expected inlet fluid conditions for the 4-loop cold overpressurization event as provided in the Westinghouse report. Provide additional detail and discussion on how the McGuire 1 and 2 cold overpressure transient and Power Operated Relief Valve (PORV) inlet conditions were determined to be represented by the Westinghouse inlet fluid conditions report.

Response

The Westinghouse Inlet Fluid Condition Report (NP-2296-LD) identifies McGuire 1 & 2 as plants for which the cold overpressurization conditions do not apply. The reason for this is that Westinghouse did not perform the specific system design and analysis. However, Duke designed the McGuire 1 & 2 Low Temperature Overpressurization Protection System (LTOPS) based on the requirements of the generic bounding analysis (Refs. A & B below) which were performed by Westinghouse for the Westinghouse Owners Group in which Duke participated.

References

A. Pressure Mitigating Systems Transient Analysis Results, Westinghouse Electric Corporation for the Westinghouse Owners Group on Reactor Coolant System Overpressurization, July, 1977.

B. Supplement to the July, 1977 Report, Pressure Mitigating Systems Transient Analysis Results, Westinghouse Electric Corporation for the Westinghouse Owners Group on Reactor Coolant System Overpressurization, September, 1977.

Question 2

In valve operability discussions on cold overpressurization transients, your submittals (Refs. 2, 3 and 4) only identify conditions for water discharge transients. According to the Westinghouse valve inlet fluid conditions report (Ref. 1), however, the PORVs are expected to operate over a range of steam, steam-water, and water conditions because of the potential presence of a steam bubble in the pressurizer and water solid operations. To indicate whether the PORVs operate for all cold overpressure events, discuss the range of fluid conditions expected for the expected types of fluid discharge and identify the test data that demonstrate operability for the low pressure steam case for both opening and closing of the PORVs.

Response

The Control Components PORV is power actuated to open and to close against system pressure. The valve does not rely on system pressure to act as a motive force to assist in valve operation for either closing or opening. The valve is also reverse seated so that increased system pressure requires increased opening force. The valve operator has been designed to open the valve against the worst case loading condition which is maximum system pressure. For valve closing, the operator design provides more closing force (air pressure plus spring force) than is available for opening.

In the EPRI program, the valve was opened at test pressures as high as 2760 psia on steam and 2540 psia on water (higher than the valve setpoint of 2350 psia). Two low pressure water tests were also run at 475 and 524 psia. The valve opened and closed in each case.

Because the valve is power actuated and does not rely on system pressure to operate, the high pressure EPRI tests bound all other operating conditions and demonstrate valve operability for all cases.

Question 3

Results from the EPRI tests on the Crosby safety valves indicate that the test blowdowns exceeded the design value of 5% for both "as installed" and "lowered" ring settings. If the blowdowns expected for McGuire 1 and 2 also exceed 5%, the higher blowdowns could cause a rise in presurizer water level such that water may reach the safety valve inlet line and result in a steam-water flow situation. Also, the pressure might be sufficiently decreased such that adequate cooling might not be achieved for decay heat removal. Discuss these consequences of higher blowdowns if increased blowdowns are expected.

Response

The McGuire safety valves use the reference typical plant ring settings provided by Crosby. EPRI tests at these representative ring settings produced blowdowns that ranged up to 9 percent.

Westinghouse was requested to analyze the affects of blowdown greater than 5 percent. Using the Loftran code and the reference four loop plant design, blowdowns up to 14 percent were analyzed. The results showed no significant effects on the safety analyses, i.e., no safety limits are violated.

QUESTIONS RELATED TO VALVE OPERABILITY

Question 4

The EPRI Test Conditions Report (Ref. 5) stated that a method of demonstrating applicability of the inlet piping for verifying the safety valve stability is to compare the total pressure drop of the inlet piping for the plant safety valve with the total pressure drop of the inlet piping for the EPRI test valve. The total inlet piping pressure drop is comprised of a frictional and acoustic wave component evaluated under steam conditions. Provide a discussion of the applicability of the test inlet piping for demonstrating the safety valve stability in McGuire 1 and 2.

Response

The McGuire safety valve inlet piping is shorter in length than the corresponding 6M6 loop seal pipe used by EPRI. Analysis of the total inlet pressure drop (frictional and acoustic wave) using the EPRI developed method (Guide For Application Of Valve Test Program Results, Rev. 2) demonstrates that the total McGuire drop is less than the corresponding EPRI test pipe. The McGuire safety valve should operate with greater stability than the EPRI test valve.

The above pressure drop analysis is for steam performance but is also applicable to the McGuire valves with loop seals. The valve opening "pop" and resulting pressure drop occurs at the end of the water loop seal passage through the valve.

Comparison of the McGuire loop seal volume to the EPRI test also shows the McGuire volume to be less. Valve effects related to loop seal passage will therefore be of a shorter duration and have less affect on the valve and piping system.

Question 5

The Westinghouse inlet fluid conditions report (Ref. 1) stated that liquid flow could exist through the PORV for the FSAR feedline break event and the extended high pressure injection event. Liquid PORV flow is also predicted for the cold overpressurization event. These same flow conditions will also exist for the Block Valve. The EPRI/Marshall Block Valve Report (Ref. 6) did not test the block valves with fluid media other than steam. The Westinghouse Gate Valve Closure Testing Program (Ref. 7) did include tests with water; however, the information presented in the report did not provide specific test results. Since it is conceivable that the electric motor operated valve (EMOV) could be expected to operate with liquid flows, discuss block valve operability with expected liquid flow conditions and provide specific test data.

Response

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 (i.e., water tests) 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 a 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, 3) results of the Marshall tests have provided sufficient information to address valve operability.

As shown in the original submittal, the McGuire PORV block valve has undergone substantial full scale testing first by Duke and then as part of the EPRI program. The submittal described significant design changes made to increase valve closing force and reduce internal friction. All of the above testing performed after the modification was successful.

In comparing valve operability on water versus steam, the two main factors in determining required thrust are the friction factor and the differential pressure (DP) across the valve disc. No specific data is available comparing water to steam friction factors. However, published data (based on proprietary information) from operator and valve manufacturers always uses a lower 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 secs, 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. This indicates that flow rate is not a consideration. The conclusion that flow rate is not a factor is also supported by the Westinghouse Gate Valve Closure Test Report.

In real plant scenarios the block valve DP on water would be less than the steam test DP of 2450 psig. The PORV opens at 2335 psig and resets at 2315 psig. For system pressures above these settings the PORV and the block valve would normally be required open relieving excess pressure. Block valve closure at 2315 psig requires 5.5 percent less closure force than at 2450 psig. Any further reduction in pressure continues to directly reduce operator closure force requirements.

Operator output force provides an additional justification for valve operability. During the valve testing, Duke established the minimum operator torque setting that provided full closure against 2450 psig steam. The operator was then set to provide a closing force 75 percent above that setting.

Based on the valve modifications and testing performed and the above discussions, PORV block valve operability for all fluid conditions is demonstrated.

Question 6

Bending moments are induced on the safety valves and PORVs during the time they are required to operate because of discharge loads and thermal expansion

of the pressurizer tank and inlet piping. Compare the predicted plant moments with the moments applied to the tested valves to demonstrate that the operability of the valves will not be impaired.

Response

The operability of safety valves was assessed by comparing valve end moments to those obtained during blowdown testing. Allowable lateral bending moment was taken to be 298,000 in-lb. The allowable bending moment is an envelope of the maximum moments from the EPRI tests that most closely represent the McGuire S/RV System. The actual end moment was found to be 295,000 in-lb. Thus, safety valve operability is insured.

The operability of the PORVs and the stop valves was also verified by qualification analysis. This analysis indicated that these valves are also acceptable.

Question 7

The Westinghouse Valve Inlet Fluid Conditions Report (Ref. 1) states that liquid discharge could be expected through the safety valves for both the feedline break and extended high pressure injection events. The EPRI 6M6 test safety valve experienced some chatter and flutter while discharging liquid at certain ring settings. Testing was terminated after observing chattering to minimize valve damage. Inspection revealed some valve damage which was presumably caused by the valve chatter and flutter. Liquid discharge for McGuire 1 and 2 may conceivably occur for longer periods of time than the EPRI testing. Thus, longer periods of valve chattering may cause severe valve damage. Discuss the implications this may have on operability and reliability of the McGuire 1 and 2 safety valves. Identify any actions that will be taken to inspect for valve damage following safety valve lift events.

Response

The two potential scenarios for water relief through the Crosby safety valves at McGuire are the feedline break and the extended high pressure injection (HPI) from power transients. Both of these accidents are analyzed in Chapter 15 of the McGuire FSAR using the conservative assumptions set forth in Regulatory Guide 1.70. For both transients, water relief through the safety valves is a direct result of extended HPI operation. For the feedline break transient, HPI is initiated on a low steam line pressure signal in the affected steam generator subsequent to reactor trip. For the extended HPI from power transient, HPI is assumed to be spuriously activated with continued operation until operator action occurs. During both of these transients, water relief through the safety valves is not predicted until after approximately 25 minutes of continuous HPI operation. This provides ample time for the operator to diagnose the transient and terminate HPI in order to prevent the primary system from reaching a water solid condition.

Duke is also participating in the Westinghouse Owners Group program to develop Emergency Response Guidelines. Duke uses these guidelines to develop in-house

procedures which continue to improve operators awareness and response to transients such as above.

Additional justification is provided by the conservative manner in which accident analyses are performed. No credit is taken for pressurizer relief through the PORVs. It is reasonable to expect that operation of the PORV's would significantly reduce the potential for water relief through the safety valves.

A final justifying item is operation of the HPI pumps themselves. In July, 1980, Westinghouse identified a potentially reportable item concerning insufficient HPI pump flow at higher pressures. Investigation by Duke of the McGuire pumps indicated that as pressures approach the safety valve setpoints, insufficient flow was developed for proper pump operation. The problem was addressed by adding a bypass line to the system. Duke's analysis shows that the HPI pumps may or may not lift the safety valves depending on the variables in the system and in the valve setpoints. This condition was reported to the NRC under the guidelines of 10CFR50.55e, reports number SD-369/80-07, 370/80-06. It is unlikely that the McGuire HPI pumps would cause sustained chatter or significant damage to the pressurizer safety valve in the event that HPI operation was not terminated.

In response to the question of actions taken following a safety valve lift, McGuire station directives require operating transients, such as a safety valve lift, be investigated and documented by the Reactor Engineer. Appropriate action would be taken to assess the valve condition depending on the nature of the occurrence and the investigation made.

Question 8

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

Response

Components in PORV control circuitry are seismically and environmentally qualified for design basis transients and accidents as described in McGuire FSAR Sections 3.10 and 3.11.

Question 9

The McGuire 1 plant safety valves are Crosby 6M6 and were tested by EPRI. EPRI testing of the 6M6 was performed at various ring settings. Your submittals (Refs. 2, 3, and 4) did not provide details discussing the applicable EPRI tests which demonstrate the operability of the plant safety valves. Your submittals did not provide the present McGuire 1 and 2 safety valve ring settings. If the plant current ring settings were not used in the EPRI tests,

the results may not be directly applicable to the McGuire 1 and 2 safety valves. Identify the McGuire 1 and 2 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 backpressure corresponding to the plant-specific ring settings were extrapolated or calculated from the EPRI test data. Identify these values so determined, and evaluate the effects of these values on the behavior of the safety valves.

Response

Crosby safety valve guide ring settings are recorded in two ways. Settings used in the field and stamped on the valve flange are relative to the "highest locked position", which is the upper limit of travel. The position of the ring is determined by tracking the number of notches the ring has been lowered from this locked position and is always a negative number. This setting is valve specific and provides for easy setting in the field. Another method used internally by Crosby and for the EPRI tests is to determine ring height relative to the level position. The level position is defined as that position where the bottom face of the adjusting ring is at the same horizontal plane as the bottom face of the disc ring. Ring positions below level are generally minus (-) and above level are positive (+). For the lower ring, the highest locked position coincides with the level position; therefore, both plant as stamped and test settings are directly comparable.

Seventeen EPRI tests were performed on the Crosby 6M6 valve with the long inlet pipe configuration. Ten of the tests (Nos. 903 to 926) were performed with "lowered" ring settings in order to increase valve opening time. The other seven tests were performed with ring settings typical of current plant settings including McGuire. Crosby recommends that only these last seven tests be used for performance comparison to McGuire. Crosby states that the same methodology was used to determine ring settings for the McGuire valves as for the EPRI valve in the typical plant series of tests. McGuire safety valve performance should be similar to the EPRI valve performance in the last seven tests.

Five tests (929, 1406, 1411, 1415, 1419) of the seven were steam tests. The valve demonstrated stable operation on steam at opening, during discharge, and at closing for all but one test. In test 1419, which had test conditions identical to the three previous tests, the valve chattered on closure. Acoustic wave pressure calculations (Reference Question 4) show that the McGuire worst case inlet configuration provides more margin to stability than does the EPRI test configuration. Valve chatter on closure is not expected to occur for McGuire.

For all the five steam tests, flow exceeded rated at the required 3 percent accumulation. It should be noted that the valve did not archieve rated lift during these tests. Crosby attributed this to a lift stop setting that combined with thermal growth in the valve, mechanically limited the lift to less than rated. This is supported by the data in that as accumulation increased from 3 to 6 percent, lift did not increase.

The safety valve ring settings for the McGuire 1 & 2 safety valves are as follows:

Valve Tag #	Serial Number	Set Pressure	Stamped Settings Noz. Ring	Stamped Settings Guide Ring	Level Position*	Guide Ring Notches Below Level
1NC-1	N56925-00-0001	2485	-18	-275	-145	-130
1NC-2	N56925-00-0002	2485	-18	-275	-158	-117
1NC-3	N56925-00-0003	2485	-18	-275	-159	-116
2NC-1	N56925-00-0004	2485	-18	-275	-152	-123
2NC-2	N56925-00-0005	2485	-18	-275	-165	-110
2NC-3	N56925-00-0006	2485	-18	-275	-169	-106
Spare 1	N56925-00-0007	2485	-18	-230	-158	-72
Spare 2	N56925-00-0008	2485	-18	-230	-154	-76
Spare 3	N56925-00-0009	2485	-18	-230	-168	-62

*Referenced to the highest locked position.

QUESTIONS RELATED TO THE THERMAL HYDRAULIC ANALYSIS OF THE INLET AND DISCHARGE PIPING

Question 10

Your submittals (Refs. 2, 3, and 4) state that a thermal hydraulic analysis of the safety/relief 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 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 over time and methods used to calculate 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) Identify where a copy of the EDS Nuclear, Inc. thermal analysis report may be obtained.

Response

(a) The safety valve system used at the McGuire station contains a loop seal to minimize operational safety valve leakage. In a system containing a water loop seal, the highest forces in the downstream piping are produced by the passage of the loop seal through the piping. There is therefore only a single case of interest for McGuire, that of a nominal valve lift

on steam wherein the loop seal passes through the valve and impacts on the downstream elbows and reducers in the piping system. This analysis is performed using fluid conditions associated with the worst case design basis event causing primary system overpressurization.

(b) The original analysis for this transient, performed in 1979, used the computer code EDSFLOW (Reference A below), which is a proprietary version of RELAP4/MOD5 (Reference B below). The manner in which fluid pressures and momenta were generated is therefore well known to NRC. Fluid forces were determined using the computer code FRCON4 (Reference C below), which operates on the output of EDSFLOW. The methods used were based on determination of the wave force due to fluid acceleration and the control surface forces due to flow resistance, calculated from the changes of momentum from control volume to control volume.

Following completion of the safety valve tests sponsored by EPRI at Combustion Engineering in 1982, a verification of the analysis tools used for McGuire was performed (Reference D below). It was found that the earlier work underestimated the loads immediately downstream of the safety valves due to dispersal of the water slug by the equilibrium models used in the analysis code, though loads further downstream were predicted conservatively. Modifications to the analysis as a result of this verification resulted in conservative values of loading for use in structural analysis.

(c) For the analysis, the worst case design basis pressurization transient reported in the McGuire FSAR was used. Valve opening time was set to 20 milliseconds. As indicated in the answer to (a) above, the fluid conditions at valve opening involved the passage through the valve of the loop seal water slug.

(d) Because the McGuire station analysis worst case depends on the passage of the water slug, it was necessary to assume a flow rate for the purposes of accelerating the slug and producing a conservative measure of the loads. When compared to the later EPRI test of the identical valve used at McGuire under prototypical lift conditions with a loop seal, it was found that the analysis used a flow rate equal to 125% of the actual valve performance. It is therefore concluded that the issue of valve flow rate and water slug acceleration was handled in a conservative manner.

(e) The analysis assumed simultaneous actuation of all safety and relief valves. Sensitivity studies indicate that calculated loads are insensitive to this assumption.

(f) The thermal hydraulic model sketch is shown in Attachment A.

(g) The report is available at DPCo/Design Engineering Department.

References

A. "EDSFLOW: Computer Program for Transient Thermal Hydraulic Analysis," EDS Nuclear, Inc.

B. "RELAP4/MOD5, A Computer Program for Transient Thermal Hydraulic Analysis of nuclear Reactors and Related Systems," ANCR-NUREG-1335, Idaho National Engineering Laboratory, September, 1976.

C. "Computer Program FRCON4 for Calculation of Force Histories from the RELAP Thermal Hydraulic Programs," Rev. 1, EDS Nuclear, Inc., August, 1978.

D. EDS Report No. 01-0092-1210, "Evaluation of EDS Nuclear Pressurizer Safety and Relief Valve System Analysis Methods," October, 1982.

QUESTIONS RELATED TO THE STRUCTURAL ANALYSIS OF THE INLET AND DISCHARGE PIPING

Question 11

Your submittals (Refs. 2, 3, and 4) state 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:

(a) A detailed description of the methods used to perform the analysis. Identify the computer programs used for the analysis and how these programs were verified.

(b) A description of the method used to apply the fluid forces to the structural model. Since the forces acting on a typical pipe segment are composed of a net, or "wave," force and opposing "blowdown" forces, describe the methods for handling both types of forces.

(c) A description of methods used to model supports, the pressurizer and relief tank connections, and the safety valve bonnet assemblies and PORV actuator.

(d) An identification of the load combinations performed in the analysis together with the allowable stress limits. Differentiate between load combinations used in the piping upstream and downstream of the valve. Explain the mathematical methods used to perform the load combinations, and identify the governing codes and standards used to determine piping and support adequacy.

(e) An evaluation of the results of the structural analysis, including identification of overstressed locations and a description of modifications if any.

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

(g) Identify where a copy of the EDS Nuclear, Inc. structural analysis report may be obtained.

Response

(a) McGuire Unit 2

The dynamic structural response for S/RV discharge events was evaluated by a step-by-step direct integration force time history analysis using SUPERPIPE.

The modeled stiffness included the effect of bending, shear, axial and torsional deformations, as well as any changes due to the effects of internal pressure on curved members as required by NB-3687 of the ASME Section III Code. The masses of the pipe, piping components, valves, pipe contents and insulation were considered in forming the mass matrix.

The forcing functions from the thermal-hydraulic analysis were applied at elbows, reducers, and tees.

For the analysis, a damping value of one percent of critical damping was used. This is based on the recommendations of Regulatory Guide 1.61. The modal damping matrix for direct integration analysis assigned arbitrarily for each mode is given as:

$$[c] = \alpha[M] + \beta[K]$$

in which

[M] = mass matrix

[K] = stiffness matrix, which was calculated by considering all rigid supports and shock suppressors (snubbers) in the piping system

α, β = factors which control the amount of damping

The factors α and β are given by:

$$\alpha = \frac{4\pi f_1 f_2 \ (f_2\lambda_2 - f_2\lambda_1)}{f_1^2 - f_2^2}$$

$$\beta = \frac{\lambda_1 f_1 - \lambda_2 f_2}{\pi(f_1^2 - f_2^2)}$$

where

f_1, f_2 = lower and upper response frequencies of the piping system respectively

λ_1, λ_2 = corresponding damping ratios to frequencies f_1, f_2, respectively

The one percent critical damping ratio was assigned to the corresponding frequency at 10 Hz and 100 Hz respectively for f_1 and f_2.

The integration time step for the time history analysis was selected to be fine enough to include the structural response to the highest frequency noted in the load histories. A time step of 0.002 seconds was used, which is considered to be accurate for the evaluation of structural response for a duration of 1.0 second.

For the linear dynamic structural analysis, support stiffness for rigid supports or shock suppressors was assumed to be infinite.

McGuire Unit 1

The analysis methods for Unit 1 is the same as for Unit 2 except for the following:

Yielding of overloaded supports was modeled in the evaluations with an interative linear analysis technique using SUPERPIPE. In the first iteration, the system was modeled with linear elastic supports. Support

stiffnesses were incorporated in order to obtain accurate load distributions and deformations. Support loads from this iteration were evaluated to determine if any supports were overloaded. A detailed evaluation of overloaded supports was performed to determine yield loads and failure deformations. In the second iteration of the analysis, support yielding was modeled by removing these supports from the model and replacing them with their time dependent inelastic resistance functions. Results of the iterative linear analysis were used to evaluate support integrity, pipe functionality, valve operability, and nozzle loads. The program SUPERPIPE was verified in accordance with the methods in the McGuire FSAR, Section 3.9.2.3.

(b) McGuire Unit 1 and 2

The general method of force history generation was to develop the total forces in the axial direction at opposing components such as bends or tees according to the following equation:

$$F = F_W + F_{CS}$$

where F_W is the wave force (due to the fluid acceleration) and F_{CS} is the control surface force in the direction of F. In general, the wave force component tends to accelerate the entire piping segment whereas the control surface force also tends to differentially expand or contract the segment. The extent of such axial deformation is dependent upon the piping properties and the magnitude of the control surface term, but is generally small for gaseous discharge problems in S/RV piping. Total forces calculated in this fashion are intended for application at the tangent points of each bend. Two total forces are, therefore, calculated at each direction change, or equivalently, two opposing total forces are calculated for each straight segment of piping. Where the piping has two bends back-to-back or the distance of a straight piping segment is relatively small, only a single net force is calculated and F is represented by just the wave force F_W.

(c) McGuire Unit 2

Rigid supports or shock suppressors were modeled as infinitely rigid.

The pressurizer is modeled as a beam with the nozzles connected to the pressurizer centroid using rigid members.

The relief tank connection is modeled as an anchor since the pipe penetrates the tank and is supported at two additional locations inside of the tank.

Safety valve bonnets and PORV actuators are modeled as rigid members with the applicable mass lumped at the bonnet or actuator centroid.

McGuire Unit 1

McGuire Unit 1 pressurizer, relief tank connection, safety valve bonnets and PORV actuators are modeled the same as for Unit 2. The supports are

modeled as linear elastic springs. See reply for question 11.A for yielded support modeling techniques.

(d) McGuire Units 1 and 2

Load combinations and allowable stresses are identical to the original analysis (Ref. FSAR Chapter 3) with the exception of the blowdown loading being included as an emergency loading.

Additionally, for Unit 1 a functionality criteria based on faulted allowables was used as follows:

$$GRAV + PRESS + BLOWDOWN \leq 3Sm, \text{ Class } 1$$

$$GRAV + PRESS + BLOWDOWN \leq 2.4\ Sh, \text{ Class } 2/3$$

Thermal and seismic loads are not included in this functionality review since:

1. Thermal stresses are self-limiting and will not impact functionality.

2. The probability of peak seismic stresses occuring simultaneously with peak blowdown stresses is extremely small.

The piping is assumed to be functional if the gravity, pressure and blowdown stresses < faulted allowable stresses using the Class 1 or 2/3 code equations as applicable. If a Class 2/3 component does not pass this code check, it is checked using Class 1 code equations. If a Class 1 analysis is performed on a Class 2/3 component, a detailed fatigue analysis must generally be performed. The fatigue analysis is not applicable for this one-time level D loading.

GOVERNING PIPING CODES & STANDARDS

1. ASME Boiler and Pressure Vessel Code, Section III, 1971 including Summer and Winter 1971 Addenda.

2. ANSI Code for POWER Piping B31.1.0, 1967.

PIPE SUPPORT CODES AND STANDARDS

(Ref. McGuire FSAR Section 3.9)

(e) McGuire Unit 2

Analysis results show that piping design is acceptable in accordance with NB-3600 of ASME Section III code. Pipe supports for McGuire Unit 2 were redesigned for the increased loads from the blowdown event to satisfy design criteria requiring modification of approximately 9 supports.

McGuire Unit 1

The piping system has been determined to be functional. All portions of the piping and supports in the Class 1 primary coolant boundary were shown to have acceptable stress levels per ASME, Section III.

All portions of the Class 2 piping were shown to meet the functionality criteria except two 3/4" vent lines and the 12" tee closest to the relief tank. Since the system is highly redundant, non-linear analysis would show the load in the 12" tee would redistribute. Strains will be small and significant flow reduction is not expected. The 3/4" vent lines are short cantilever branches and are shown to be overloaded in the liner-elastic analysis due to high accelerations. It is not reasonable to assume failure due to this type loading with a low number of cycles. In addition, failure of the vent lines is not a safety concern.

The relief tank nozzle is overloaded in the axial direction. However, this is not a problem since the forces will redistribute and be carried by the support 2' above the nozzle.

Modifications to Unit 1 similar to Unit 2 are not reasonable because:

1. All portions of the piping and supports in the Class 1 primary coolant boundary have acceptable stress levels per ASME, Section III.

2. High radiation levels exist in the pressurizer cavity.

3. The pressurizer cavity is very congested and there is a lack of support anchoring space.

4. The results of the analysis indicated that the system is functional for a safety/relief valve discharge event demonstrating the adequacy of McGuire Unit 1 SRV and PORV piping and supports in accordance with NUREG 0737, Item II.D.1.A.

(f) The structural model is shown in Attachment B.

(g) The EDS Nuclear, Inc. structural analysis report is available at DPCo/Design Engineering Department.

Question 12

According to results of EPRI tests, high frequency pressure oscillations of 170-260Hz typically occur in the piping upstream of the safety valve while loop seal water passes through the valve. An evaluation of this phenomenon is documented in the Westinghouse report WCAP 10105 (Ref. 8) and states that the acoustic pressures occurring prior to and during safety valve discharge are below the maximum permissible pressure. The study discussed in the Westinghouse report determined the maximum permissible pressure for the inlet piping and established the maximum allowable bending moments for Level C

Service Condition in the inlet piping based on the maximum transient pressure measured or calculated. While the internal pressures are lower than the maximum permissible pressure, the pressure oscillations could potentially excite high frequency vibration modes in the piping, creating bending moments in the inlet piping that should be combined with moments from other appropriate mechanical loads. Provide one of the following: (1) a comparison of the expected peak pressures and bending moments with the allowable values reported in the WCAP report or (2) justification for other alternate allowable pressure and bending moments with a similar comparison with peak pressures and moments induced in the plant piping.

Response

The EPRI tests showed that no pipe damage occurred due to the high frequency pressure oscillations. The piping had little response to the high frequency pressure oscillations as expected. The maximum expected pressure was 5000 psia (Ref. A below). This is essentially the same as the WCAP report pressure (5100 psia). The maximum expected bending moments are less than the maximum allowable moments in the WCAP report.

Reference

A. "Pressure Oscillations in Safety Valve Inlet Piping", EPRI Letter to Utility Consultants, March 17, 1982.

REFERENCES

1. Valve Inlet Fluid Conditions for Pressurizer Safety and Relief Valves in Westinghouse Plants, EPRI NP-2296, December 1982.

2. Transmittal letter W. O. Parker, Jr. to H. R. Denton, NRC, "McGuire Nuclear Station Docket Nos. 50-369, 50-370," March 29, 1982.

3. Transmittal letter W. O. Parker, Jr. to H. R. Denton, NRC, "McGuire Nuclear Station Safety Valve Operability Report NUREG-0737, Item II.D.1," June 30, 1982.

4. Transmittal letter H. B. Tucker to H. R. Denton, NRC, "McGuire Nuclear Station PWR Safety/Relief Valve Piping Evaluation NUREG-0737, Item II.D.1," November 1, 1982.

5. EPRI PWR Safety and Relief Valve Test Program Test Condition Justification Report, EPRI NP-2460, December 1982.

6. EPRI/Marshall Electric Motor Operated Block Valve, EPRI NP-2514-LD, July 1982.

7. EPRI Summary Report: Westinghouse Gate Valve Closure Testing Program, Engineering Memorandum 5683, Revision 1, March 31, 1982.

8. Review of Pressurizer Safety Valve Performance as Observed in the EPRI Safety Valve and Relief Valve Test Program, WCAP-10105, June 1982.

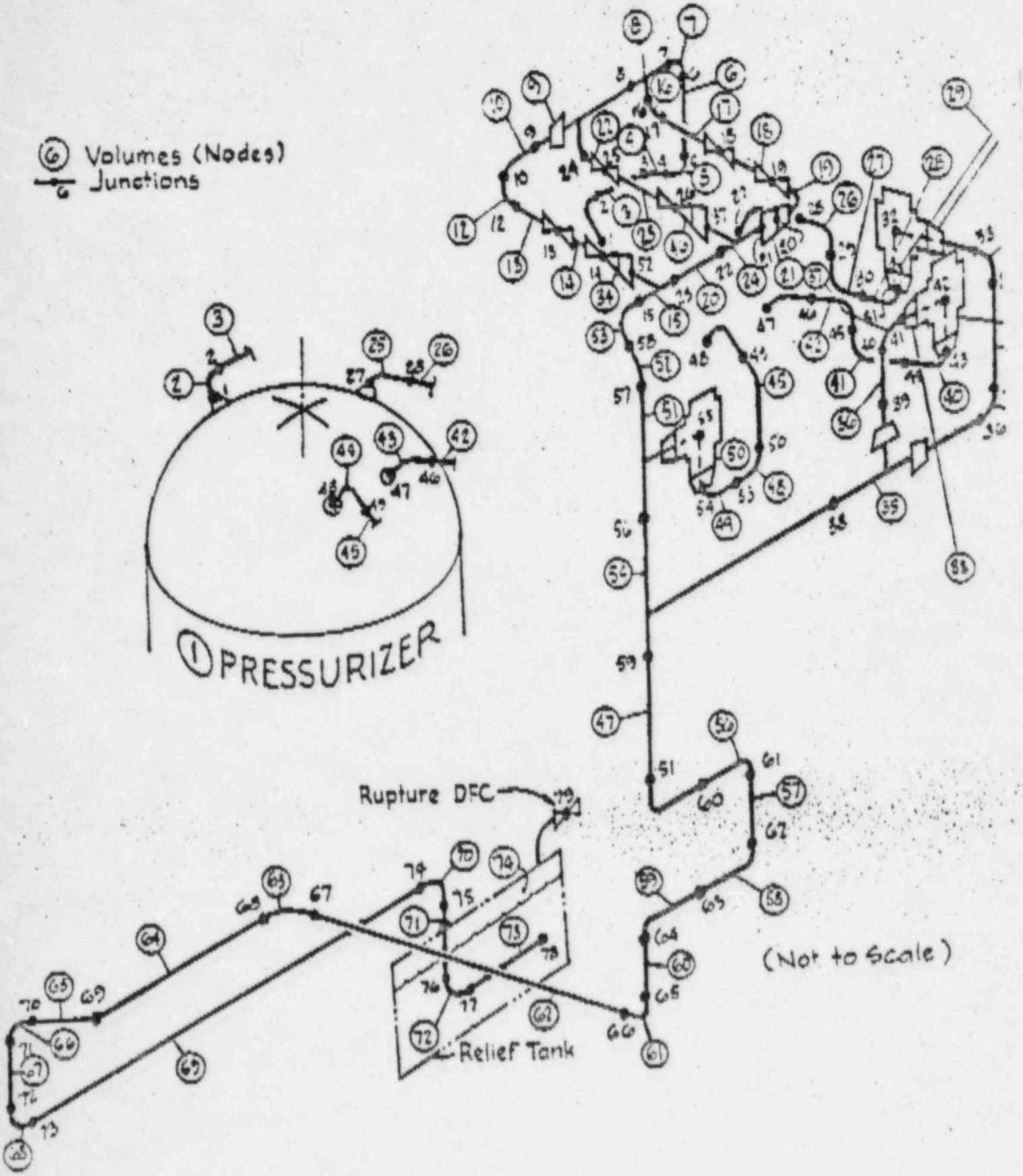


FIGURE 1 DUKE MCGUIRE PRESSURIZER
RELIEF LINE RELAP 4/MOD 5 MODEL

Sheet 1 of 2

Attachment A

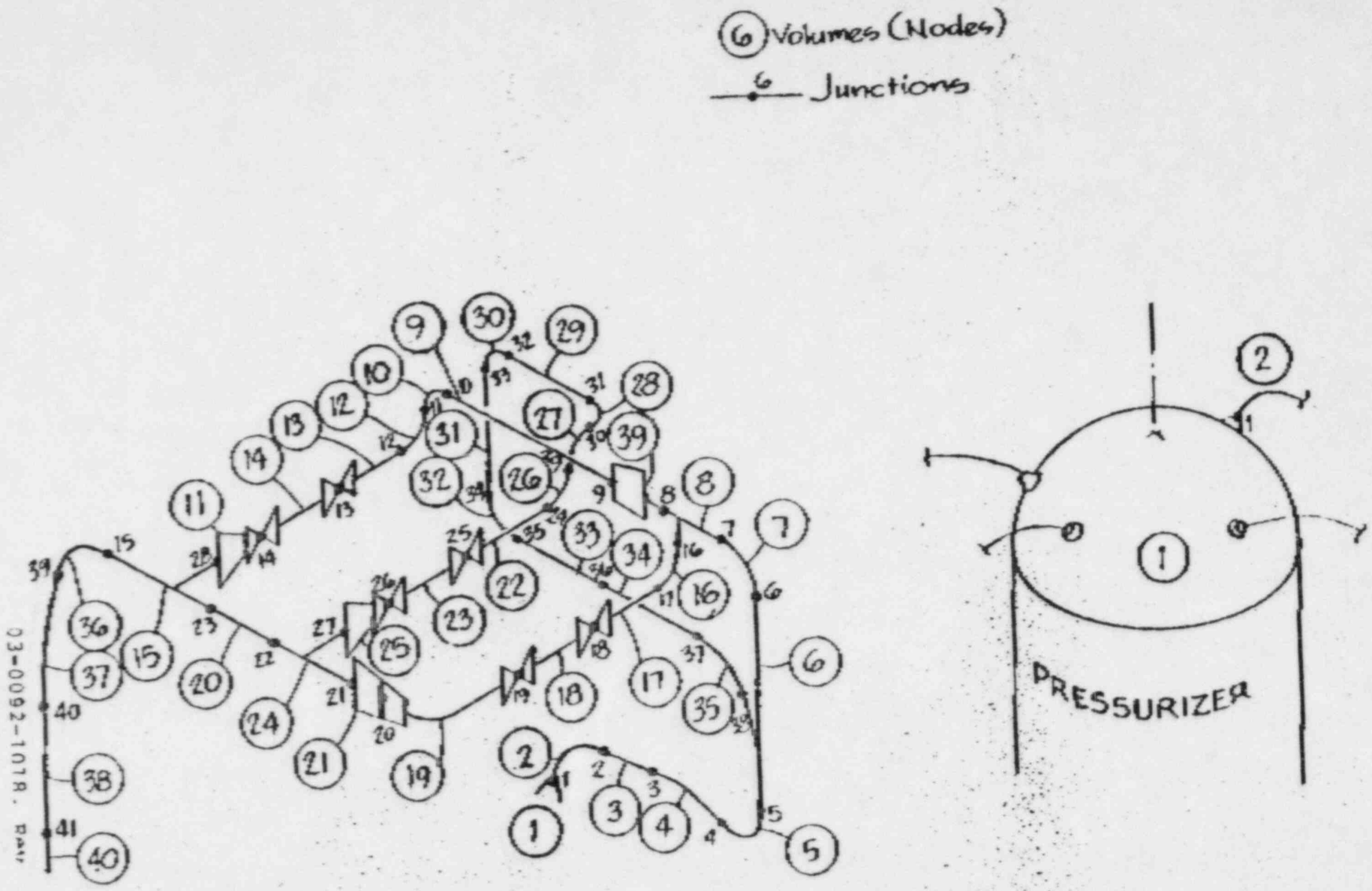
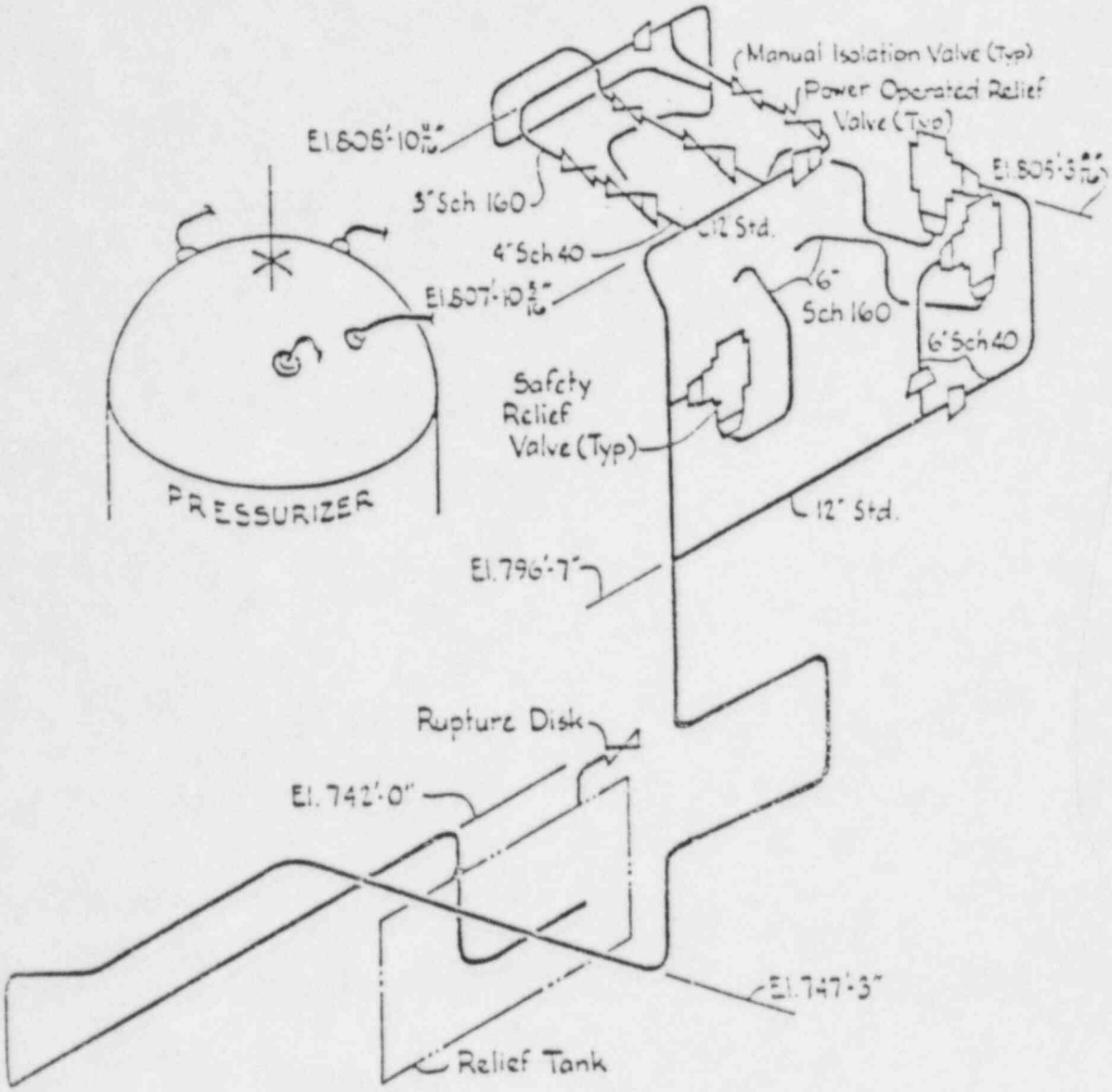


FIGURE 1 REVIEW RELIEF VALVE LINE MODEL Sheet 2 and 2

Attachment B



NOTES:

1. Blowdown Forces Are Applied At The Tangent Points Of Elbows, Reducers And Tees In The Direction Of The Straight Pipe Axis.
2. Masses Are Lumped At Points Of Discontinuity And At A Maximum Spacing Of "L" In Straight Pipe.

Pipe Size	Schedule	"L" (Inches)
12"	Std.	87
6"	160	68
6"	40	65
4"	40	54
3"	160	44