TEXAS UTILITIES SERVICES INC.
2001 BRYAN TOWER DALLAS, TEXAS 75201-3050

Log # TXX-3684
File # 910.4

June 9, 1983

Mr. B. J. Youngblood
U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, D.C. 20555

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION
DOCKET NOS. 50-445 AND 50-446
MODEL D-4 D-5 STEAM GENERATOR TUBE
VIBRATIONS

Dear Mr. Youngblood:

Texas Utilities letter TXX-3490 dated March 15, 1982, written in response to the D. G. Eisenhut letter concerning tube vibration in Westinghouse Model D-4 and D-5 steam generators, stated that CPSES would rely on the Westinghouse program implemented to understand the tube vibration phenomena and to permit operation of the pre-heat steam generators.

Westinghouse has now concluded the major portion of their investigation and testing program and has determined that modifications to the Steam Generators and the Feedwater Systems are required to permit unrestricted operation of the steam generators. The modifications consist of two parts.

1. Approximately 116 tubes in the preheat section will be hydraulically expanded at the "B" and "D" support plate elevations. A complete description of the expansion process including an analysis of the safety implications of the expansion process are contained in the Westinghouse Counterflow Preheat Steam Generator Tube Expansion Report dated June, 1983.

2. The main feedwater and auxiliary feedwater systems are modified to allow 10% of the feedwater flow to bypass the preheat section and enter the steam generator via the auxiliary nozzle. A description of the piping, valve and instrumentation changes resulting from this modification is contained in the attached revised FSAR Section 10.4.7. In addition, the slight changes in some of the core thermal-hydraulic parameters resulting from the split feed modification are included in revised FSAR sections 4.1, 4.4, 5.1 and 15.2.

B001
1/40

Westinghouse has determined through extensive analysis and testing that the combination of these two modifications will reduce tube vibration to an acceptable level. Documentation of the investigation and testing performed to determine to exact vibration and wear mechanisms, and the subsequent verification of the tube expansion process and 90-10 split feedwater bypass modification to reduce the vibration to an acceptable level, is contained in the Westinghouse Counterflow Preheat Steam Generator Vibration Summary Report dated June 1983.

Extensive reviews and analysis have been performed to verify that the feedflow modifications do not result in unacceptable safety consequences during normal and accident conditions. The analyses included seismic events, high and moderate energy line breaks, water-hammer, normal and abnormal plant startups and shutdowns and all Chapter 15 design basis events. The conclusion of these analyses is that no unacceptable consequences result from the split feed modification. Modifications to Unit 1 Steam Generators and Feedwater Systems will begin June 15, 1983.

Sincerely,

H. C. Schmidt

H. C. Schmidt

BSD/grr

TABLE 4.1-1 (Sheet 1 of 6)

REACTOR DESIGN COMPARISON TABLE

	Thermal and Hydraulic Design Parameters	CPSES Units 1 & 2	W. B. McGuire Units 1 & 2	
1.	Reactor core heat output (MWt)	3411	3411	
2.	Reactor core heat output (10^6 Btu/hr)	11,641	11,641	
3.	Heat generated in fuel (%)	97.4	97.4	
4.	System pressure, nominal (psia)	2250	2250	
5.	System pressure, minimum steady state (psia)	2220	2220	
6.	Minimum departure from nucleate boiling ratio for design transients	>1.30	>1.30	
7.	DNB correlation	"R" (W-3 with Modified Spacer Factor)	"R" (W-3 with Modified Spacer Factor)	
	Coolant Flow			
8.	Total thermal flow rate (10^6 lb_m/hr)	142.0	144.7	41
9.	Effective flow rate for heat transfer (10^6 lb_m/hr)	133.7	133.9	
10.	Effective flow area for heat transfer (ft^2)	51.1	51.1	
11.	Average velocity along fuel rods (ft/sec)	16.6	16.6	41
12.	Average mass velocity (10^6 lb_m/hr-ft^2)	2.62	2.62	

TABLE 4.1-1 (Sheet 2 of 6)

REACTOR DESIGN COMPARISON TABLE

Thermal and Hydraulic Design Parameters	CPSES Units 1 & 2	W. B. McGuire Units 1 & 2	
Coolant Temperature			
13. Nominal inlet (^{o}F)	559.6	559.1	41
14. Average rise in vessel (^{o}F)	59.3	58.4	
15. Average rise in core (^{o}F)	62.5	62.5	
16. Average in core (^{o}F)	590.9	590.4	
17. Average in vessel (^{o}F)	589.2	588.3	
Heat Transfer			
18. Active heat transfer, surface area (ft^2)	59,700	59,700	
19. Average heat flux, ($Btu/hr\text{-}ft^2$)	189,800	189,800	
20. Maximum heat flux for normal operation, ($Btu/hr\text{-}ft^2$)	440,300	440,300	
21. Average linear power (kW/ft)	5.44	5.44	
22. Peak linear power for normal operation (kW/ft)	12.6	12.6	
23. Peak linear power resulting from overpower transients operator errors, assuming a maximum overpower of 118% (kW/ft)	18.0[a]	18.0[a]	
24. Heat flux hot channel factor, F_Q	2.32[b]	2.32[b]	

REACTOR DESIGN COMPARISON TABLE

Thermal and Hydraulic Design Parameters	CPSES Units 1 & 2	W. B. McGuire Units 1 & 2
39. Clad material	Zircaloy-4	Zircaloy-4
Fuel Pellets		
40. Material	UO_2 sintered	UO_2 sintered
41. Density (% of Theoretical)	95	95
42. Diameters (in.)	0.3225	0.3225
43. Length (in.)	0.530	0.530
Rod Cluster Control Assemblies		
44. Neutron absorber		
Full length, all Hf or Ag alloy design	Hf or Ag-In-Cd alloy	Ag-In-Cd
Full length, hybrid B_4C design	Ag-In-Cd and B_4C	-
45. Cladding Material	Type 304 SS-cold worked	Type 304 SS-cold worked
46. Clad thickness		
All Hf or Ag alloy design (in.)	0.0185	0.0185
Hybrid B_4C design (in.)	0.0385	-

TABLE 4.1-1 (Sheet 5 of 6)

REACTOR DESIGN COMPARISON TABLE

Thermal and Hydraulic Design Parameters	CPSES Units 1 & 2	W. B. McGuire Units 1 & 2
47. Number of clusters, full length/part length	53/-	53/8
48. Number of absorber rods per cluster	24	24
Core Structure		
49. Core barrel, I.D./O.D. (in.)	148.0/152.5	148.0/152.5
50. Thermal shield	Neutron pad design	Neutron pad design
Structure Characteristics		
51. Core diameter, equivalent (in.)	132.7	132.7
52. Core height, active fuel (in.)	143.7	143.7
Reflector Thickness and Composition		
53. Top, water plus steel (in.)	10	10
54. Bottom, water plus steel, (in.)	10	10
55. Side, water plus steel (in.)	15	15
56. H_2O/U molecular ratio (core), lattice (cold)	2.41	2.41

TABLE 4.1-1 (Sheet 6 of 6)

REACTOR DESIGN COMPARISON TABLE

Thermal and Hydraulic Design Parameters	CPSES Units 1 & 2		W. B. McGuire Units 1 & 2
Feed Enrichment, w/o			
	Unit 1	Unit 2	
57. Region 1	1.60	1.40	2.10
58. Region 2	2.40	2.10	2.60
59. Region 3	3.10	2.90	3.10

a. See Section 4.3.2.2.6.

b. This is the value of F_Q for normal operation.

TABLE 4.4-1 (Sheet 1 of 3)

THERMAL AND HYDRAULIC COMPARISON TABLE

Design Parameters	CPSES Units 1 and 2	W. B. McGuire Units 1 and 2	
Reactor core heat output (MWt)	3411	3411	
Reactor core heat output (10^6 Btu/hr)	11,641	11,641	
Heat generated in fuel (%)	97.4	97.4	
System pressure, nominal (psia)	2250	2250	
System pressure, minimum steady state (psia)	2220	2220	
Minimum DNBR at nominal conditions			
Typical flow channel	2.05	2.06	41
Thimble (cold wall) flow channel	1.71	1.72	
Minimum DNBR for design transients	>1.30	>1.30	
DNB correlation	"R" (W-3 with Modified Spacer Factor)	"R" (W-3 with Modified Spacer Factor)	
Coolant Flow			
Total thermal flow rate (10^6 lb_m/hr)	142.0	144.7	41
Effective flow rate for heat transfer (10^6 lb_m/hr)	133.7	133.9	
Effective flow area for heat transfer (ft^2)	51.1	51.1	
Average velocity along fuel rods (ft/sec)	16.6	16.6	41
Average mas velocity (10^6 lb_m/hr-ft^2)	2.62	2.62	

TABLE 4.4-1 (Sheet 2 of 3)

THERMAL AND HYDRAULIC COMPARISON TABLE

Design Parameters	CPSES Units 1 and 2	W. B. McGuire Units 1 and 2	
Coolant Temperature			
Nominal inlet (^{o}F)	559.6	559.1	41
Average rise in vessel (^{o}F)	59.3	58.4	
Average rise in core (^{o}F)	62.5	62.5	
Average in core (^{o}F)	590.9	590.4	
Average in vessel (^{o}F)	589.2	588.3	
Heat Transfer			
Active heat transfer, surface area (ft^2)	59,700	59,700	
Average heat flux (Btu/hr-ft^2)	189,800	189,800	
Maximum heat flux for normal operation (Btu/hr-ft^2)	440,300[a]	440,300[a]	
Average linear power (kW/ft)	5.44	5.44	
Peak linear power for normal operation (kW/ft)	12.6[a]	12.6[a]	
Peak linear power resulting from overpower transients/operator errors, assuming a maximum overpower of 118% (kW/ft[b])	18.0	18.0	
Peak linear power for prevention of centerline melt (kW/ft[c])	>18.0	>18.0	
Power density (kW per liter of core[d])	104.5	104.5	
Specific power (kW per kg uranium[d])	38.4	38.4	

[a] This limit is associated with the value of F_Q = 2.32

[b] See Section 4.3.2.2.6.

[c] See Section 4.4.2.11.6.

[d] Based on cold dimensions and 95% of theoretical density fuel.

TABLE 4.4-1 (Sheet 3 of 3)

THERMAL AND HYDRAULIC COMPARISON TABLE

Design Parameters	CPSES Units 1 and 2	W. B. McGuire Units 1 and 2	
Fuel Central Temperature			
Peak at peak linear power for prevention of centerline melt (^{o}F)	4700	4700	
Pressure drop[e]			
Across core (psi)	26.6 $\pm$ 2.7	25.8 $\pm$ 2.6	41
Across vessel, including nozzle (psi)	48.2 $\pm$ 7.2	48.2 $\pm$ 7.2	

[e] Based on best estimate reactor flow rate as discussed in Section 5.1.

TABLE 4.4-2

THERMAL-HYDRAULIC DESIGN PARAMETERS FOR
ONE OF FOUR COOLANT LOOPS OUT OF SERVICE

Total core heat output (MWt)	2389
Total core heat output (10^6 Btu/hr)	8154
Heat generated in fuel (%)	97.4
Nominal system pressure (psia)	2250
Coolant Flow	
Effective thermal flow rate for heat transfer (10^6 lb_m/hr)	96.4
Effective flow area for heat transfer (ft^2)	51.1
Average velocity along fuel rods (ft/sec)	11.8
Average mas velocity (10^6 $lb_m/hr\text{-}ft^2$)	1.89
Coolant Temperature	
Design nominal inlet (^oF)	552.4
Average rise in core (^oF)	62.2
Average in core (^oF)	535.0
Heat Transfer	
Active heat transfer surface area (ft^2)	59,700
Average heat flux ($Btu/hr\text{-}ft^2$)	132,900
Minimum DNBR at nominal conditions	>1.74
Minimum DNBR for design and anticipated transients	$\geq$1.30

41

TABLE 5.1-1

(Sheet 1 of 2)

SYSTEM DESIGN AND OPERATING PARAMETERS

Plant design life, (years)	40	
Nominal operating pressure, (psig)	2235	
Total system volume including pressurizer and surge line, (ft^3)	12,500	14
System liquid volume, including pressurizer water at maximum guaranteed power, (ft^3)	12,000	
Pressurizer spray rate, maximum (gpm)	900	
Pressurizer heater capacity, (kW)	1800	
Pressurizer relief tank volume, (ft^3)	1800	

System Thermal and Hydraulic Data

	4 Pumps Running	3 Pumps Running	
NSSS power, (MWt)	3425	2398	
Reactor power, (MWt)	3411	2389	
Thermal design flows, (gpm)			
Active loop	95,700	101,400	
Idle loop	-	30,900	14
Reactor	382,800	273,300	
Total reactor flow, (10^6 lb/hr)	142.0	102.5	
Temperatures, (^oF)			
Reactor vessel outlet	618.8	605.8	41
Reactor vessel inlet	559.6	552.4	
Steam generator outlet	559.3	552.2	
Steam generator steam	544.6	539.6	14
Feedwater	440.0	401.0	

TABLE 5.1-1

(Sheet 2 of 2)

Steam pressure, (psia)	1000		
Total steam flow, (10^6 lb/hr)	15.14	10.03	14
Best estimate flows, (gpm)			
Active loop	100,800	107,000	41
Idle loop	-	28,400	
Reactor	402,000	292,600	
Mechanical design flows, (gpm)			
Active loop	105,000	111,300	
Idle loop	-	30,600	
Reactor	420,000	303,300	

System Pressure Drops 14

Reactor vessel P, (psi)	46.5
Steam generator P, (psi)	38.0
Hot leg piping P, psi	1.3
Pump suction piping P, (psi)	3.3
Cold leg piping P, (psi)	3.3
Pump head, (feet)	287

TABLE 10.1-1
MAJOR STEAM AND POWER CONVERSION EQUIPMENT
SUMMARY DESCRIPTION MAXIMUM GUARANTEED

Component	Power: Maximum Guaranteed Rating	Power: Valves Wide Open	
Steam Generator			
Steam flow rate (total 4 steam generators), lb/hr	15,140,016	15,897,012	
Feedwater inlet temperature, F	440	446.0	
Steam outlet temperature, F	544.6	543.3	
Steam outlet pressure, psia	1000	990	
Steam generator reactor coolant inlet temperature, F	618.8	621.6	41
Steam generator reactor coolant outlet temperature, F	559.3	557.8	
Turbine Generator			
Steam to turbine generator, lb/hr	15,140,016	15,897,012	
Throttle inlet pressure, psia	975	970	
Throttle enthalpy, Btu/lb	1191.4	1191.5	
Percent moisture, percent	0.38	0.38	
Guaranteed output, kV	1,160,706	1,203,378	
Power factor	0.90	0.90	
Hydrogen pressure, psig	60	60	

5.2-2 and 5.2-3. Fabrication of reactor coolant pressure boundary materials is also discussed in Section 5.2.3, particularly in Sections 5.2.3.3 and 5.2.3.4.

Testing has justified the selection of corrosion-resistant Inconel-600, a nickel-chromium-iron alloy (ASME-SB-163), for the steam generator tubes and divider plate. The interior surfaces of the reactor coolant channel heads and nozzles are clad with austenitic stainless steel. The primary side of the tubesheet is weld clad with Inconel (ASME-SB-163). The tubes are roller or hydraulically expanded into the tubesheet holes after the ends are tack rolled and seal welded. The recessed fusion welds made to the tubesheet cladding are performed in
compliance with Sections III and IX of the ASME Code and are thoroughly 7
inspected before each tube is expanded.

Approximately 96 tubes in the preheat section of unit 1 and 2 steam generators have been hydraulically expanded at the "B" and "D" support plate elevations to reduce the tube vibration phenomena experienced in
Westinghouse counterflow preheat steam generators. The material 41
properties of the expanded section of the tubes are discussed in Reference 4.

Code cases used in material selection are discussed in Section 5.2.1. The extent of conformance with Regulatory Guides 1.84 and 1.85 is also discussed in Section 5.2.1 and Appendix 1A(N).

During manufacture, cleaning is performed on the primary and secondary sides of the steam generator in accordance with written procedures which follow the guidance of Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants," and the ANSI Standard N45.2.1-1973, "Cleaning of Fluid Systems and Associated Components for Nuclear Power Plants." Onsite cleaning and cleanliness control is in accordance with Westinghouse recommendations given in Westinghouse process specifications, as discussed in Section 5.2.3.4.

The fracture toughness of the materials is discussed in Section 5.2.3.3. Adequate fracture toughness of ferritic materials in the reactor coolant pressure boundary is provided by compliance with Appendix G of 10CFR50 and with NB-2300 of Section III of the ASME Code. Per the discussion in Section 5.4.2.3, consideration of fracture toughness is only necessary for materials used for Class 1 components.

5.4.2.1.2 Steam Generator Design Effects on Materials

Several features are employed to control the regions where deposits
would tend to accumulate. To avoid extensive crevice areas between the
7 tube and tubesheet, the tubes are roller or hydraulically expanded for
the full depth surface of the tubesheet, after their ends are seal
welded to the Inconel (ASME-SB-163) cladding on the primary side of the
tubesheet. A flow distribution plate located below the preheat section
encourages recirculating flow to sweep the tubesheet before turning
upward through the tube bundle. This plate also serves to separate the
tubesheet from the colder feedwater entering at the preheat section. A
separate auxiliary feedwater nozzle provided in the upper shell avoids
introducing cold water into the preheat section, and, thus, maximizes
the integrity of steam generator materials.

5.4.2.1.3 Compatibility of Steam Generator Tubing with Primary and Secondary Coolants

As mentioned in Section 5.4.2.1.1, corrosion tests, which subjected the steam generator tubing material Inconel-600 (ASME-SB-163) to simulated steam generator water chemistry, have indicated that the loss due to general corrosion over the 40 year plant life is insignificant compared to the tube wall thickness. Testing to investigate the susceptibility of heat exchanger construction materials to stress corrosion in caustic and chloride aqueous solutions has indicated that Inconel-600 has excellent resistance to general and pitting type corrosion in severe operating water conditions. Many reactor years of successful operation have shown the same low general corrosion rates as indicated by the laboratory tests.

available, operating experience to date has not indicated that steam generator performance decreases over a long time period. Adequate tube area is selected to ensure that the full design heat removal rate is achieved.

5.4.2.5.2 Natural Circulation Flow

The driving head created by the change in coolant density as it is heated in the core and rises to the outlet nozzle initiates convection circulation. This circulation is enhanced by the fact that the steam generators, which provide a heat sink, are at a higherelevation than the reactor core which is the heat source. Thus natural circulation is assured for the removal of decay heat during hot shutdown in the unlikely event of loss of forced circulation.

5.4.2.5.3 Mechanical and Flow Induced Vibration Under Normal Operation

In the design of Westinghouse steam generators, the potential for tube wall degradation attributable to mechanical or flow induced excitation has been thoroughly evaluated. The evaluation included detailed analyses of the tube support systems for various mechanisms of tube vibration.

The primary cause of tube vibration in heat exchangers is hydrodynamic excitation due to secondary fluid flow on the outside of the tubes. In the range of normal steam generator operating conditions, the affects of primary fluid flow inside the tubes and mechanically induced tube 41
vibration are considered to be negligible.

To evaluate flow induced tube vibration in the preheater region of the tube bundle, Westinghouse undertook an extensive program employing data from operating plants, full and partial scale model tests and analytical tube vibration models. Operating plant data consisted of

tube wear data from pulled tube evaluations and eddy current tests, and tube motion data from accelerometers installed inside selected tubes. Model testing generated tube wear data, flow velocity distributions, tube motion parameters and flow induced tube vibration forcing functions. The tube vibration analyses applied the forcing functions to produce tube motion data. The results of this evaluation were consistent with the early operating experience of preheat steam generators.

On the basis of an extensive model test and analysis program, Westinghouse designed, verified and implemented a modification to the steam generator to reduce tube vibratory response to preheater inlet flow excitation. Additionally, the magnitude of the flow forcing function was reduced through implementation of a preheater flow bypass arrangement in the feedwater system. The verification of the
41 performance of the modifications in reducing tube excitation and response was done with input from a full scale test under simulated conservative flow and tube support conditions.

Fatigue of the tubes in the preheater region which are subject to flow induced excitation is not a concern since the maximum resultant stresses in the tube are below the endurance limit of the material.

For areas of the tube bundle other than the preheater, parallel flow analyses were performed to determine the vibratory deflections. These analyses indicate that the flow velocities are sufficiently low such that they result in negligible fatigue and vibratory amplitudes. The support system, therefore, is deemed adequate with regard to parallel flow excitation.

To evaluate cross flow at the exit of the downcomer flow to the tube bundle and at the top of the bundle in the U-bend area, Westinghouse performed an experimental research program of cross flow in tube arrays with the specific parameters of the steam generator. Air and water

model tests were employed. The results of this research indicate that these regions of the bundle are not subject to the vortex shedding mechanism of tube excitation. Vortex shedding was found not to be a significant mechanism in these two regions for the following reasons:

A. Flow turbulence in the downcomer and tube bundle inlet region inhibit the formation of Von Karman vorticies.

B. Both axial and cross flow velocity components exist on the tubes. The axial flow component disrupts the Von Karman vortices.

This research program was also the basis for evaluation of the fluidelastic mechanism due to cross flow at the tubesheet. The evaluation showed the adequacy of the tube support arrangement.

Flow turbulence can result in some tube excitation in these regions. This excitation is of little concern, however, since: 41

A. Maximum stresses in the tubes are at least an order of magnitude below the fatigue endurance limit of the tube material, and

B. Tube support arrangements preclude significant vibratory motion.

In summary, tube vibration has been thoroughly evaluated. Mechanical and primary flow excitation are considered negligible. Secondary flow excitation has been evaluated. From this evaluation, it is concluded that if tube vibration does not occur, the magnitude will be limited. Tube fatigue due to the vibration is judged to be negligible. Any tube wear resulting from the tube vibration would be limited and would progress slowly. This allows use of a periodic tube inservice inspection program for detection and follow of any tube wear. This inservice inspection program, in conjuction with tube plugging criteria, provides for safe operation of the steam generators.

5.4.2.5.4 Allowable Tube Wall Thinning Under Accident Conditions

An evaluation is performed to determine the extent of tube wall thinning that can be tolerated under accident conditions. Under such a postulated design basis accident, vibration is of short enough duration that there is no endurance problem. The results of a study made on "D series" (0.75 inch nominal diameter, 0.043 inch nominal thickness) tubes under accident loading are discussed in Reference [3] and show that a minimum wall thickness of 0.026 inches would have a maximum faulted condition stress (i.e., due to combined LOCA and Safe Shutdown Earthquake loads) that is less than the allowable limit. This thickness is 0.010 inches less than the minimum steam generator tube wall thickness 0.039 reduced to 0.036 inches by the assumed general corrosion and erosion loss of 0.003 inches.

increases in diameter and the ligaments between the holes in the plate may break. Ovalization of the tubes at the intersections results in
7 high strains, leading to tensile stress on the tube ID and possible leakage by intergranular stress assisted cracking. A similar result may be induced at the apex of the first row (i.e., the smallest radius)
1 U-bend if sufficient distortion of the top support plate flow slots
Q122.1 occurs, resulting in leg displacement, ovalization, and high strains. Development to this stage presupposes condenser leakage which results in chloride contamination of the steam generator liquid.

Approximately 96 tubes in the Preheat section of the Unit 1 and Unit 2 steam generators have expanded sections at the "B" and "D" support
41 plate elevations. These tubes have nominal clearances at these support plates of 2 mills. The denting phenomena has been investigated for expanded tubes and it has been found that they are not adversely affected. (See reference 4)

The tube leakage and support plate effects do not pose a safety problem with respect to release of radioactivity or effects on accident calculations, but the frequency of leakage and resultant repair
1 shutdowns does present an economic concern to the operators. The
Q122.1 utilization of preventive plugging, therefore, serves to maintain availability and to permit orderly planning for long-term corrective action.

The occurrence of denting has thus far been associated exclusively with plants having a history of chloride contamination due to condenser leakage. Moreover, it has recently been noted that Maine Yankee and Millstone Point 2, non-Westinghouse plants which have used AVT exclusively, have apparently incurred denting also; sea water is used for cooling the condensers at both of these plants.

Research into the causes of denting was initiated shortly after the discovery of the denting condition. Initially, dented tubes were removed for laboratory examination. Subsequently tube support plate samples containing sections of tubing were also removed for analysis from operating plants. 1 Q122.1

The initial hard data on the nature of the denting phenomenon were derived from these tube/support plate samples which revealed the thick oxide buildup, the tube diameter reduction, and chemical makeup of the

public health and safety. The methods used for the analysis of the Safe Shutdown Earthquake and LOCA conditions are given in Section 3.9N.1.

5.4.14.4 Tests and Inspections

Weld inspection and standards are specified in accordance with Section V of the ASME Code. Welder qualifications and welding procedures are specified in accordance with Section IX of the ASME Code.

REFERENCES

1. "Reactor Coolant Pump Integrity in LOCA," WCAP-8163, September 1973.

2. Shabbits, W. O., "Dynamic Fracture Toughness Properties of Heavy Section A533 Grade B Class 1 Steel Plate," WCAP-7623, December 1970.

3. "Evaluation of Steam Generator Tube, Tubesheet and Divider Plant Under Combined LOCA Plus SSE Conditions," WCAP-7832, December 1973.

4. Westinghouse Report "Counterflow Preheat Steam Generator Tube Expansion Report," June 1983. 41

is transported through the final two stages of feedwater heating to the steam generators.

During power operation each steam generator feedwater pump takes
suction from the Condensate System and discharges through a
common header to the high-pressure feedwater heaters. One steam
generator feedwater pump is required to operate during power
41 operation of up to 50% of the rated power. From 50-percent power
to full power, both steam generator feedwater pumps are required,
with each pump providing 50-percent of the required flow. Prior
to turbine synchronization, water is supplied by the Auxiliary
Feedwater System, and the steam generator feedwater pumps operate
in a standby mode with minimum flow recirculation back to the
main condensers.

Each steam generator feedwater pump is fitted with a minimum recirculation control system which protects the pumps from damage at low loads by ensuring a minimum flow.

Leakages through the pump are detected by monitoring the temperature of the seal injection system drains.

The dual admission feedwater pump turbine drivers operate with steam from two sources. During low-load conditions, high pressure steam is supplied to the turbines from the Main Steam Supply System steam dump header. During normal operation, low-pressure steam is supplied from the MSR in the Main Steam Supply System. Gland steam is provided to the turbines from the turbine gland steam seal supply system.

The flow from the two steam generator feedwater pumps combines at the pump discharge, then divides into two streams for the final two stages of regenerative feedwater heating (heaters Nos. 1 and 2). The two heater trains and the common bypass join downstream of the high-pressure heaters to form a single common header for

temperature equalization. From this common header, an individual feedwater line supplies each steam generator.

Each individual main feedwater line to a steam generator incor-
porates a Feedwater Bypass System. The function of the Feedwater 10
Bypass System is to minimize the potential occurrence of a water
hammer in the steam generators, and to mitigate the flow induced 41
tube vibration in the steam generators.

A Feedwater Bypass System associated with an individual Main Feedwater line consists of three lines with associated instrumentation and controls as follows:

A feedwater bypass line connects each main feed line, just up-
stream of the main isolation valve, to the auxiliary feedwater
nozzle in the upper portion (above normal water level) of each
steam generator. Each bypass line has its own containment iso-
lation valve (Feedwater Preheater Bypass Valve) which is air
operated. The objective of this bypass line is to minimize the 10
potential occurrence of pressure transients and to prevent
feedwater from entering the main feedwater nozzle at startup and
during certain other operating conditions.

The feedwater tempering line connects the main feed line to the
feedwater bypass line inside containment to provide a continuous
feedwater bypass flow during normal plant operating conditions in
order to minimize thermal transients in the nozzle and connecting
piping when flow is transferred to the auxiliary FW nozzle from
the main FW line and to minimize the flow induced tube vibration
in the steam generators. It contains an annubar and an air 41
operated butterfly valve. The feedwater tempering line is
designed to provide a 90:10 flow split in the main feedwater line
and the tempering line, respectively, at 100% rated output.

In addition, a small bypass line around the feedwater isolation
valve is provided to purge cold feedwater from the main feedwater
10 line between the isolation valve and the steam generator
feedwater nozzle. This line incorporates a restricting flow
orifice and an air operated globe type shutoff valve which also
serves as a containment isolation valve.

Connections from the Condensate System are provided both upstream and downstream of the heaters to permit flushing of the heaters. The upstream connection can also be used to fill the system and the steam generators and to provide feedwater directly from the condensate pumps during the early stages of startup.

A sampling system connection is provided on each feedwater line for monitoring feedwater chemistry. The sampling system is also connected to various points in the Condensate, Main Steam, and Heater Drain Systems as shown on Figure 10.4-20.

Condensate and feedwater chemistry are controlled as described in Section 10.3.5. This system uses all volatile chemical treatment in conjunction with a Condensate Cleanup System, which is described in Section 10.4.6.

Chemical feed to each steam generator is introduced at a point downstream of the auxiliary feedwater supply connection to the Feedwater System for adjustments to the water chemistry during steam generator layup periods only.

3. Electrical Systems

Safe shutdown of the plant does not rely upon the availability of either the Condensate System or the Steam Generator Feedwater System. However, the portion of the Feedwater System from the check valve upstream from the Containment isolation valve to the

steam generator feedwater nozzle is nuclear-safety-related and automatic isolation of these lines is required during emergency conditions. To ensure isolation of these lines, the isolation valves, feedwater isolation bypass valves, feedwater control valves, feedwater control bypass valves and steam generator preheater bypass valves are all tripped closed by separate, redundant control circuits and solenoids and are powered from two Class 1E-125 VDC power systems, maintaining the proper train separation. The independence and redundance of these two Class 1E-125 VDC power systems is described in Section 8.3.2.

The rest of the valves and equipment in the condensate and feedwater systems are powered from non-Class 1E systems.

10.4.7.3 Safety Evaluation

The requirements of 10 CFR Part 50, GDC 57, for Containment isolation are satisfied by one stop valve on each feedwater line outside the Containment (see Section 6.2.4.). With loss of flow in the normal direction, the check valve upstream of the stop valve closes and is held closed by back pressure. In addition, the stop valve can be closed and secured by remote operation.

The Feedwater System from the steam generators, back to and including the check valve upstream of the Containment isolation valve, is designated as Safety Class 2 and is designed to the requirements of seismic Category I systems (see Section 3.2.1). For an analysis of the effects of a break in the Safety Class portion of the Feedwater System, see Section 10.4.9. The portion of the system upstream from this valve and the Condensate System is non-seismic Category I except for the Condensate Storage Tank which is designated Safety Class 3, seismic Category I.

The Condensate and Feedwater Systems are designed to the requirements of the codes listed in Subsection 10.4.7.1. The potential for pipe rupture caused by internal pressure and temperature is as discussed in Section 3.6. Short lengths of pipe are installed above the turbine operating floor and could be fractured by a heavy object carried by the gantry crane or by a turbine-generated missile; but such an occurrence is extremely unlikely. A rupture of the condensate piping anywhere in

valve. The feedwater bypass system also include a feedwater isolation bypass valve.

To minimize pressure transient potential, it is necessary to prevent the introduction of cold water to the steam generator through the main feedwater nozzle at any time when significant void may be present. Therefore, total feedwater flow is not aligned to the normal feedwater nozzle during a startup until feedwater line temperature and steam generator pressure and water level are above set limits. Conversely, feedwater flow is diverted to the auxiliary feedwater nozzle from the main feedwater nozzle during a shutdown.

The tempering line inside the containment, which connects the main feedwater line and the feedwater bypass line, is designed to minimize the thermal transients in the steam generator nozzles and to preclude the flow induced tube vibration in the pre-heater section of the steam generator (see reference 21) by maintaining a feedwater flow split during feedwater injection through the main feedwater line. The designed feedwater flow split is 90:10 between the main feedwater line and the tempering line, respectively, at 100 percent rated power output. In addition, selected steam generator tubes in the preheater section have been expanded at two support plate locations to minimize 41
vibration (reference 20). Tests have shown that the maximum allowable main feedwater line flow at any power level should not exceed 90 percent of the total feedwater flow, corresponding to 100 percent rated power output. To achieve the required flow split, the tempering line has been modified to minimize hydraulic resistance by incorporating an air-operated piston-type butterfly valve and an annubar for each tempering line.

10.4.7.4 Tests and Inspection

Each feedwater heater, drain cooler, pump, and valve receives a shop hydrostatic test. Prior to initial operation, the completed Condensate and Feedwater System is to receive a field hydrostatic test and inspection. These tests are performed according to the applicable codes listed in Subsection 10.4.7.1. Periodic tests and inspections of the system are to be performed in conjunction with scheduled maintenance outages.

Periodic in-plant tests are conducted to demonstrate the ability of the feedwater isolation valves to respond to a test close signal. The valves must close within the specified time. The valves are designed and constructed with provision for periodic inservice testing of partial valve stroke. Provisions are made in the trip mechanism for all solenoid-operated valves to be exercised without interrupting availability of the trip mechanism.

c. Feedwater Flow

Feedwater flow must be above a low-flow set-point, as
10 determined by a flow switch, associated with the feedwater
flow Venturi meters.

The set-point for these flow switches corresponds to
41 approximately 5.3 percent of full feedwater flow.

d. Feedwater Temperature

The feedwater temperature must be above approximately 200F (as measured by resistance temperature detectors on the main feedwater lines). In addition, the difference in temperature between the RTD's installed outside containment, downstream of the FIVs and those mounted at a piping low point on the feedwater lines inside containment, near the main feedwater nozzle must be within a few degrees of each other. This arrangement of temperature sensors is
10 used to preclude pocketing of cold water at the piping low point during startups and, also, to avoid the possibility of a single RTD open circuit failure causing a false temperature permissive signal to open the FIVs.

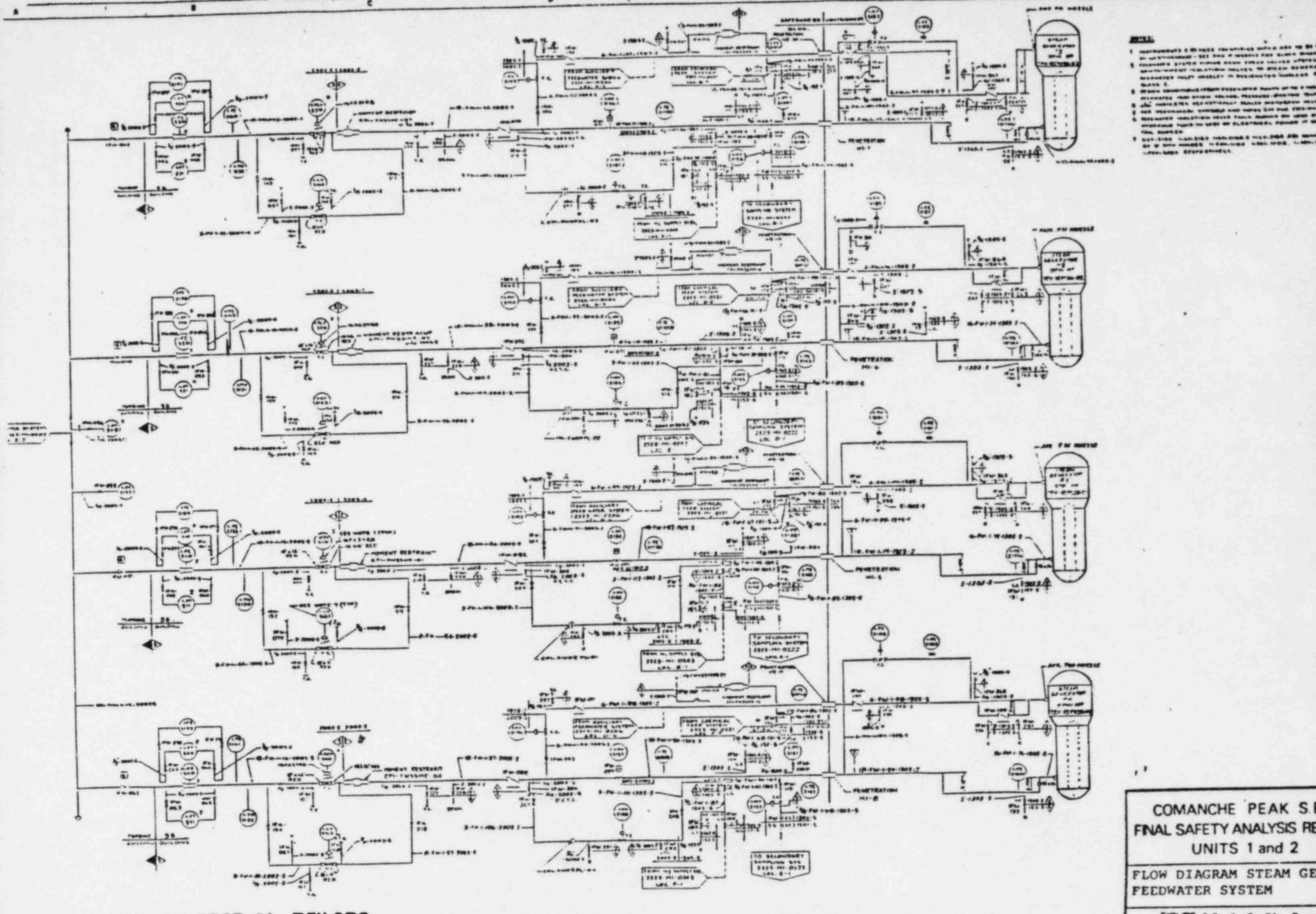
Once the temperature permissives have been cleared allowing the FIV to open, the FIVs can remain open, irrespective of temperature providing the FW flow remains high (above the low flow set point as described in item (c) above). Interlocks are provided for this condition.

2. FEEDWATER PREHEATER BYPASS VALVE (FPBV)

The FPBV bypasses feedwater from the main feedwater line to the upper auxiliary nozzle. It also serves as a containment

20. Westinghouse Report "Counterflow Preheat Steam Generator Tube Expansion Report," June 1983.

21. Westinghouse Report "Counterflow Preheat Steam Generator Vibration Summary," June 1983. 41



REF. DWG. 2323-MI-0203-01 REV.CP2

COMANCHE PEAK S.E.
FINAL SAFETY ANALYSIS REP
UNITS 1 and 2

FLOW DIAGRAM STEAM GEN
FEEDWATER SYSTEM

FIGURE 10.4-9 Sh 2 of

15.0.3.2 Initial Conditions

For accident evaluation, the initial conditions are obtained by adding the maximum steady state errors to rated values. The following steady state errors are considered:

1.	Core power	$\pm$ 2 percent allowance for calorimetric error
41 2.	Average Reactor Coolant System temperature	$\pm$ 5.5°F allowance for controller deadband and measurement error and steam generator fouling penalty
3.	Pressurizer pressure	$\pm$ 30 pounds per square inch (psi) allowance for steady state fluctuations and measurement error

Initial values for core power, average Reactor Coolant System temperature and pressurizer pressure are selected to minimize the initial departure from nucleate boiling ratio (DNBR) unless otherwise stated in the sections describing specific accidents. Table 15.0-2 summarizes the initial conditions and computer codes used in the accident analyses.

15.0.3.3 Power Distribution

The transient response of the reactor system is dependent on the initial power distribution. The nuclear design of the reactor core minimizes adverse power distribution through the placement of control rods and operating instructions. Power distribution may be characterized by the radial factor ($F_{\Delta H}$) and the total peaking factor (F_q). The peaking factor limits are given in the Technical Specifications.

occurs.

6. Auxiliary feedwater is delivered to two steam generators.

7. Secondary system steam relief is achieved through the self-actuated safety valves. Note that steam relief will, in fact, be through the power-operated relief valves or condenser dump valves for most cases of loss of normal feedwater. However, for the sake of analysis these have been assumed unavailable.

41 8. The initial reactor coolant average temperature is 5.5^{o}F higher than the nominal value since this results in a greater expansion
5 of the RCS water during the transient and, thus, in a higher maximum water volume level in the pressurizer.

The loss of normal feedwater analysis is performed to demonstrate the adequacy of the reactor protection and engineered safeguards systems (e.g., the Auxiliary Feedwater System) in removing long term decay heat and preventing excessive heatup of the RCS with possible resultant RCS overpressurization or loss of RCS water.

As such, the assumptions used in this analysis are designed to minimize the energy removal capability of the system and to maximize the possibility of water relief from the coolant system by maximizing the coolant system expansion, as noted in the assumptions listed above.

One such assumption is the loss of external (offsite) AC power. This assumption results in coolant flow decay down to natural circulation conditions and a corresponding reduction in the steam generator heat transfer coefficient. Following a loss of offsite AC power, the first few seconds of a loss of normal feedwater transient will resemble the
5 transient response presented in Section 15.3.2 for the complete loss of forced reactor coolant flow.

The cases analyzed assume a double ended rupture of the largest feedwater pipe at full power. Major assumptions made in the analyses are as follows:

1. The plant is initially operating at 102 percent of engineered safeguards power.

2. Initial reactor coolant average temperature is 5.5^{o}F above the nominal value, and the initial pressurizer pressure is 30 psi above its nominal value. | 41

3. No credit is taken for the pressurizer power operated relief valves or pressurizer spray.

4. Initial pressurizer level is at the nominal programmed value plus 2 percent (error); initial steam generator water level is at the nominal value.

5. No credit is taken for the high pressurizer pressure reactor trip. Note: This assumption is made for calculational convenience. Pressurizer power operated relief valves and spray could act to delay the high pressure trip. Assumptions 3 and 5 permit evaluation of one hypothetical, limiting case rather than two possible cases: one with a high pressure trip and no pressure control; and one with pressure control but not high pressure trip.

6. Main feedwater flow to all steam generators is assumed to be lost at the time the break occurs (all main feedwater spills out through the break).

7. The worst possible break area is assumed. This maximizes the blowdown discharge rate following the time of trip, which maximizes the resultant heatup of the reactor coolant.

TABLE 15.0-3

NOMINAL VALUES OF PERTINENT PLANT PARAMETERS UTILIZED IN THE ACCIDENT ANALYSES[a]

Thermal output of NSSS (MWt)	See Table 15.0-2
Core inlet temperature (^{o}F)	559.6 |41
Vessel average temperature (^{o}F)	589.2
Reactor Coolant System pressure (psia)	2250
Reactor coolant flow per loop (gpm)	94,400
Steam flow from NSSS (lb/hr)	15,140,000
Steam pressure at steam generator outlet (psia)	1000
Maximum steam moisture content (%)	0.25
Assumed feedwater temperature at steam generator inlet (^{o}F)	440
Average core heat flux (Btu/hr-ft^2)	189,800

[a] Steady state errors discussed in Section 15.0.3 are added to these values to obtain initial conditions for transient analyses.