VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

W. L. STEWART
VICE PRESIDENT
NUCLEAR OPERATIONS

January 14, 1986

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
Attn: Mr. Lester S. Rubenstein, Director
PWR Project Directorate #2
Division of PWR Licensing-A
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Serial No.: 85-136C
E&C/MSW/bh:3529C
Docket Nos: 50-280
50-281
License Nos.: DPR-32
DPR-37

Gentlemen:

VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION UNIT NOS. 1 AND 2
PARTIAL EXEMPTION FROM GENERAL DESIGN CRITERION 4
REQUEST FOR ADDITIONAL INFORMATION

At the meeting with members of your staff on December 19, 1985, we presented for your review and discussion the information related to our request for partial exemption from General Design Criterion 4 for Surry Power Station which was provided previously in our November 5, 1985 (Serial No. 85-136) and December 3, 1985 (Serial No. 85-136A) letters. Following those discussions, your staff requested supplemental information from the results of our analyses in five areas to complete their review. Our understanding of the requested information was transmitted to you in our letter of December 27, 1985 (Serial No. 85-136B). The requested information is provided in the Attachment.

We appreciate the responsiveness demonstrated by your staff in addressing this issue to support our schedule for implementing the requested relief during the upcoming 1986 Surry refueling outages. If you should require any additional information, please contact us as soon as possible.

Very truly yours,

W. L. Stewart

W. L. Stewart

Attachment

A001
1/1

cc: Dr. J. Nelson Grace
Regional Administrator
NRC Region II

Mr. Donald J. Burke
NRC Resident Inspector
Surry Power Station

Mr. Terence L. Chan
NRC Surry Project Manager
PWR Project Directorate #2
Division of PWR Licensing-A

ATTACHMENT

Item 1

Provide a summary of piping stresses (similar to Table 1 of the Loading Evaluation in our December 3, 1985 letter) including the main steam and pressurizer surge line breaks (i.e. the controlling breaks).

Response 1

Table 1A provided herein includes the results of the load combination including the effects of the controlling postulated main steam and pressurizer surge line ruptures on primary loop piping stress. These results are for the proposed support geometry with selected large bore and small bore snubbers removed. All stresses are well within the allowable stress.

TABLE 1A

Level of Stress as a Percentage of Code Allowable Stress

Loading	Hot Leg	Crossover Leg	Cold Leg	Code Allowable Stress
Thermal	38.6%	15.6%	7.4%	S_A
Pressure + Deadweight	68.0%	48.7%	53.3%	$1.0S_h$*
Pressure + Deadweight + OBE	65.6%	65.0%	60.0%	$1.2S_h$*
Pressure + Deadweight + DBE	49.6%	51.1%	48.9%	$1.8S_h$*
Pressure + Deadweight + DBE + (Pipe Rupture of Main Steam or Surge Line)	96.9%	58.8%	52.3%	($1.8S_h$*)**

*S_h = 15 Ksi

**Use of an allowable stress of 1.8 S_h is conservative both with respect to the UFSAR and to $2.4S_h$ which is permitted by the current ASME code.

Item 2

Provide a comparison of the maximum pipe stress locations between the existing and proposed configurations for seismic condition and the controlling break.

Response 2

The steam generator outlet elbow is the location of maximum stress in the Reactor Coolant loop piping for both OBE and DBE seismic loads. This is true for both the existing support configuration and the proposed configuration with selected snubbers eliminated.

The location of maximum stress in the reactor coolant loop piping due to postulated main steam line rupture is the steam generator inlet elbow. For a surge line rupture, the maximum stress occurs in the hot leg where the surge line intersects. The points of maximum stress remain the same for both the existing and proposed support configurations.

Item 3

Provide a comparison of the component support Factors of Safety (similar to Table 2 of the Loading Evaluation in our December 3, 1985 letter) for the existing and proposed configurations including the controlling loads of main steam and pressurizer surge line breaks.

Response 3

Table 2A provides the Factors of Safety for the supports under combined Deadweight, Pressure, Thermal and SRSS (DBE + Pipe Rupture) loading where:

$$\text{Factor of Safety} = \frac{\text{Allowable Load}}{\text{Calculated Combined Load}}$$

For the component interfaces, the Allowable Load is taken from the Westinghouse Equipment Specification and, therefore, contains additional conservatism.

All support components exhibit Factors of Safety of over 1.8 with the exception of the upper Steam Generator supports, which are discussed further herein. The snubbers and lateral guides of the upper steam generator supports are governed by postulated ruptures of the Main Steam lines. Surry was designed prior to the development of the current methodology for determining pipe break locations and these Main Steam line breaks were originally postulated not on basis of piping stress, but to provide the maximum possible loads on the Steam Generator supports. The governing postulated breaks are not the terminal end breaks, but postulated longitudinal splits on the side of the elbow above the nozzle at the top of the Steam Generators. The stresses in that portion of the Main Steam lines are low, and therefore, only arbitrary intermediate breaks would be postulated at the elbow under current criteria. In addition, longitudinal splits are no longer postulated at all. Because the ruptures were postulated to give maximum design loads, the Factor of Safety is 1.05 for the lateral guides. If a circumferential break was postulated at the end of the elbow in the steam line, the maximum thrust loads on the upper Steam Generator supports would be less than half of the current design loads due to the effect of the flow restrictors which were installed at the top of the Steam Generators during the Steam Generator Replacement Project (1978-81). In view of this, we are considering a subsequent request for a change to the licensing basis to eliminate these postulated splits in order to down-size the upper snubbers. However, the intent of this exemption request is to satisfy the original licensing criteria*, though in this instance, it is more severe than current criteria would require. The proposed change to eliminate the lower snubbers has a negligible effect on the loads on the upper Steam Generator support guides, which continue to have a Factor of Safety of slightly over 1.05. Similarly, there is no increase in loads on the upper Steam Generator snubbers due to the proposed change.

*Except for elimination of the main coolant loop ruptures and use of SRSS combination of DBE + Pipe Rupture

TABLE 2A

FACTORS OF SAFETY FOR COMPONENT SUPPORTS UNDER COMBINED LOADS

COMPONENT	FACTOR OF SAFETY* EXISTING DESIGN	FACTOR OF SAFETY* PROPOSED DESIGN
Steam Generator Shell	2.5	2.4
Steam Generator Upper Support		
Component	2.8	2.8
Upper Guides	1.1**	1.1**
Snubbers	1.3**	1.4**
Steam Generator Lower Support		
Hanger Rod	1.8	1.8
Swivel End Coupling	2.3	2.3
Steam Generator Foot		
Vertical Force	4.0	4.2
Tangential Force	7.4	7.2
RC Pump Foot		
Vertical Force	11.9	11.3
Tangential Force	34.2	48.5
Radial Force	43.7	58.0
RC Pump Support		
Upper Vertical	4.5	4.3
Upper Horizontal	5.3	4.8
Lower Vertical	3.8	3.5
Lower Diagonal	3.0	3.0

* Factor of Safety = Allowable Load/Total Load of Deadweight, Pressure, Thermal, and SRSS (DBE + Pipe Rupture)
**See Response 3 discussion

Item 4

Present the Reactor Coolant Pump (RCP) frequencies and modes for significant RCP motion.

Response 4

The request for information on the natural frequencies and modes for significant Reactor Coolant Pump (RCP) motion resulted from concerns that elimination of the 12"-bore snubbers and of the 4"-bore snubbers on the RCP support diagonals could cause significant changes in the modes of pump vibration. (Because the four 12"-bore snubbers at the top of the Steam Generator are retained, there was no concern about significant changes to Steam Generator motion.) The natural frequencies and modes for significant RCP motion are listed in Table 3A. All significant RCP modes below 33 Hz are included for your information and review. The amplitude of pump motion was judged significant if the displacement in any direction of any of the nodes representing the pump exceeded 25% of the maximum normalized modal displacement. Because the Stone & Webster model includes a more detailed modeling of the supports, it was used as the basis for this review. In addition to providing a comparison of support configuration with and without snubbers, the frequencies for similar modes from the Westinghouse analysis are given in parentheses for comparison.

The comparison shown in the table illustrates that the dynamic characteristics of the Reactor Coolant Pump are not significantly affected by the proposed removal of the snubbers. Many modes are virtually unaffected and the greatest change was a 17% drop in the frequency of a pump rocking mode. The comparison of the modal frequencies between the two models clearly indicates the results are in close agreement, particularly for modes below 25 Hz, and provides further verification of results.

TABLE 3A

Vibrational Modes Causing Significant Reactor Coolant Pump Motion

Natural Frequency* (Hz) Existing Design	With Snubbers Removed	Description of Mode
5.21 (5.38)	4.96 (4.97)	Pump rocking perpendicular to the cold leg
9.45 (11.11)	7.81 (9.20)	Pump rocking parallel to the cold leg
9.67 (9.80)	9.66 (9.76)	Pump rocking induced by vertical motion of the steam generator.
19.77 (18.74)	18.37 (17.55)	Pump rocking and translation perpendicular to the cold leg.
21.52 (23.20)	19.03 (20.61)	Steam generator rocking and bending parallel to hot leg with pump rocking and translation. For the case with snubbers removed, the motion is dominated by pump translation and rocking perpendicular to the cold leg.
25.08 (25.00)	25.02 (27.11)	Pump vertical motion and rocking. The greatest motion in this mode occurs centrally in the cold leg which is moving in the vertical plane.
31.35 (27.01)	28.50 (24.62)	Pump rocking and translation accompanied by torsional vibration of the cold leg stop valve and swinging of the pump suction line.
30.26 (-)	30.35 (32.60)	Steam generator bending in the plane of the pump suction line causing pump rocking and translation.
- (28.23)	31.73 (25.78)	Torsional vibration and rocking of the cold leg stop valve with pump motion.

*Frequencies without parentheses are from SWEC analysis; those in parentheses are from Westinghouse analysis.

Item 5

Discuss verification of the input geometry used in the computer models.

Response 5

The two analytical models prepared by Westinghouse and Stone & Webster (Figures 3 and 4, respectively, of the Loading Evaluation of our December 3, 1985 submittal) were revisions to the mathematical models prepared in 1970-71 for the original design analysis of the primary coolant loop piping and equipment supports.

These models had been developed based on the Unit 1 design drawings 11448-FP-8A (Rev. 9) and 11448-FP-8B (Rev. 8). The corresponding Unit 2 drawings, 11548-FP-8A (Rev 5) and 11548-FP-8B (Rev 4) are sufficiently similar to Unit 1 to justify use of the same model. The Reactor Coolant System (RCS) piping is shop- fabricated "fitting-to-fitting" construction with strict tolerances, due to the relatively short lengths of pipe and the requirement to accurately locate the branch piping. In a very real sense, the plant is designed around the primary loop, and the types of interferences which cause minor routings and support relocations in other piping systems, which can lead to as-built differences, are not permitted in the RCS loop piping.

The primary equipment supports are heavy castings, forgings, or frame structures shop fabricated to strict tolerances. The components and supports were then accurately positioned in accordance with detailed installation specifications, and finally the loop piping was installed between the components. The RCS primary piping is supported only by the RCS primary equipment. Therefore, there is no concern about incorrect support location.

Surry was the first nuclear plant to replace its Steam Generators, and extensive measurements were taken prior to making the initial cuts for their removal to ensure that the replacement Steam Generators were installed in the same locations within strict tolerances. Because this was accomplished, there was no need to revise the referenced design drawings.

The computer models prepared by Westinghouse and SWEC for the analyses supporting this exemption request were based on the original models. As part of the current reanalysis, these models were reviewed and modified to reflect the steam generator replacement and the proposed snubber elimination. Personnel involved in these reviews differed from those involved in generating the original models. The calculations, including modifications to the analytical models, were independently reviewed.

The support configuration is essentially the same as the original configuration, except for removal of the snubbers. The Reactor Coolant Pump support stiffness matrix without snubbers provided to Westinghouse by SWEC is essentially the same as previously provided for the deadweight and thermal cases (i.e., with snubbers inactive). The stiffness matrix for the steam generator reflects eliminating the lower snubbers, but retaining the upper snubbers.

As discussed in the Loading Evaluation of our December 3, 1985 submittal, comparison of interface loads calculated by the two models was performed to ensure the results of the two models were consistent; the significant interface loads were found to be within 15%. Additional confirmation of the consistency between the two models is provided by the close agreement of the natural frequencies and mode shapes provided in the response to Item 4.

Upon approval of this exemption request, the construction activities will be performed during the 1986 refueling outages under Design Changes in accordance with our Design Control Program, which incorporates Quality Control verification of completed work.