ATTACHMENT 1

Technical Specification Pages With Changes Indicated

Page	Specification	Change Description
3/4 4-7	3.4.2.1, Reactor Coolant System, Safety Valves - Shutdown	Change ± 1% to ± 3%. Modify surveillance requirements to allow cold set. Delete "*" Note.
3/4 4-8	3.4.2.2, Reactor Coolant System, Safety Valves - Operating	Change ± 1% to ± 3%. Add Note to exempt Mode 3.
B 3/4 4-2	3/4.4.2, Bases, Reactor Coolant System	Deletes wording to allow testing in Mode 3. Removes specific year reference of ASME code. Corrects administrative omission.

3/4.4.2 SAFETY VALVES

SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.2.1 A minimum of one pressurizer code safety valve shall be OPERABLE with a lift setting of 2485 PSIG ± ~~1%*~~ 3%

APPLICABILITY: MODES 4 and 5.

ACTION:

With no pressurizer code safety valve OPERABLE, immediately suspend all operations involving positive reactivity changes and place an OPERABLE residual heat removal loop into operation in the shutdown cooling mode.

SURVEILLANCE REQUIREMENTS

4.4.2.1 ~~No additional Surveillance Requirements other than those required by Specification 4.0.5.~~

THE SURVEILLANCE REQUIREMENTS OF SPECIFICATION 4.0.5 HAVE BEEN MET OR THE LIFT SET PRESSURE IS ADJUSTED UNDER COLD CONDITIONS.

~~*The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.~~

LIMITING CONDITION FOR OPERATION

3.4.2.2 All pressurizer code safety valves shall be OPERABLE with a lift setting of 2485 PSIG ± ~~1%~~ 3%.*

APPLICABILITY: MODES 1, 2 and 3.#

ACTION:

With one pressurizer code safety valve inoperable, either restore the inoperable valve to OPERABLE status within 15 minutes or be in at least HOT STANDBY within 6 hours and in at least HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.2.2 No additional Surveillance Requirements other than those required by Specification 4.0.5.

*The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

#MODE 3 APPLICABILITY IS EXEMPTED UNDER THE FOLLOWING CONDITIONS:
1. THERE HAS BEEN AT LEAST 5 DAYS OF OPERATION IN MODE 5 OR LOWER SINCE THE REACTOR WAS LAST CRITICAL, AND
2. ALL RCCAs ARE FULLY INSERTED WITH ALL CRDMs DE-ENERGIZED

BASES

3/4.4.2 SAFETY VALVES

PLUS 3% ACCUMULATION

The pressurizer code safety valves operate to prevent the RCS from being pressurized above its Safety Limit of 2735 psig. Each safety valve is designed to relieve 420,000 lbs per hour of saturated steam at the valve set point. The relief capacity of a single safety valve is adequate to relieve any overpressure condition which could occur during shutdown. In the event that no safety valves are OPERABLE, an operating RHR loop, connected to the RCS, provides overpressure relief capability and will prevent RCS overpressurization. In addition, the Overpressure Protection System provides a diverse means of protection against RCS overpressurization at low temperatures.

During operation, all pressurizer code safety valves must be OPERABLE to prevent the RCS from being pressurized above its safety limit of 2735 psig. The combined relief capacity of all of these valves is greater than the maximum surge rate resulting from a complete loss of load assuming no reactor trip until the first Reactor Protective System trip set point is reached (i.e., no credit is taken for a direct reactor trip on the loss of load) and also assuming no operation of the power operated relief valves or steam dump valves.

Demonstration of the safety valves' lift settings ~~will occur only during shutdown and~~ will be performed in accordance with the provisions of Section XI of the ASME Boiler and Pressure Code, ~~1974 Edition.~~

3/4.4.3 PRESSURIZER

The limit on the maximum water volume in the pressurizer assures that the parameter is maintained within the normal steady state envelope of operation assumed in the SAR. The limit is consistent with the initial SAR assumptions. The 12 hour periodic surveillance is sufficient to ensure that the parameter is restored to within its limit following expected transient operation. The maximum water volume also ensures that a steam bubble is formed and thus the RCS is not a hydraulically solid system. The requirement that a minimum number of pressurizer heaters be OPERABLE enhances the capability of the plant to control Reactor Coolant System pressure and establish natural circulation.

3/4.4.4 RELIEF VALVES (PORV's)

The power operated relief valves and steam bubble function to relieve RCS pressure during all design transients up to and including the design step load decrease with steam dump. Operation of the power operated relief valves minimizes the undesirable opening of the spring-loaded pressurizer code safety valves. Each PORV has a remotely operated block valve to provide a positive shutoff capability should a relief valve become inoperable.

ATTACHMENT 2

DESCRIPTION OF AMENDMENT REQUEST

SAFETY EVALUATION

DESCRIPTION OF AMENDMENT REQUEST

Technical Specification (TS) 3/4.4.2 provides the basis for operation with respect to the pressurizer safety valves (PSVs). The PSVs operate to prevent the Reactor Coolant System (RCS) from being pressurized above its Safety Limit of 2735 psig.

TS 3/4.4.2.1, "Safety Valves-Shutdown," states that while in Modes 4 and 5, a minimum of one PSV is required to be operable. However, with no PSVs operable, the action statement allows continued operation in Modes 4 and 5, provided all positive reactivity changes are immediately suspended and an operable loop of RHR is placed into operation in the shutdown cooling mode. The relief capacity of a single safety valve is adequate to relieve any overpressure condition which could occur during shutdown. In the event that no safety valves are operable, an operating RHR loop connected to the RCS provides overpressure relief capability. This is due to the RHR suction relief valves serving as a portion of the Overpressure Protection System (TS 3/4.4.9.3) which provides a diverse means of overpressure protection when the RCS is below 300°F.

TS 3/4.4.2.2, "Safety Valves-Operating," states that while in Modes 1, 2 and 3, all PSVs are required to be operable. Also, if one PSV is inoperable, the action statement requires the restoration of all PSVs to operable status within 15 minutes or a plant shutdown is required. During operation, all PSVs must be OPERABLE to prevent the RCS from being pressurized above its safety limit of 2735 psig. The combined relief capacity of all of these valves is greater than the maximum surge rate resulting from a complete loss of load assuming no reactor trip until the first Reactor Protective System trip set point is reached (i.e., no credit is taken for a direct reactor trip on the loss of load) and also assuming no operation of the power operated relief valves or steam dump valves.

Both TSs require that the lift setting of the PSVs be 2485 psig ± 1% and that the surveillance requirements of TS 4.0.5 are met to determine operability.

This request is comprised of two basic changes. The first change is to increase the present lift setting tolerance of ±1% to ±3% for both TSs. The second change is to modify the TSs to allow plant heatup to Mode 3 with the PSVs setpoint adjusted under cold conditions (cold set). This requires modifying the surveillance requirement and eliminating the "*" note on TS 3.4.2.1 in addition to adding a note that exempts Mode 3 applicability under certain conditions on TS 3.4.2.2.

The PSVs were designed (i.e., manufactured) to meet the 1971 Edition--including the Winter 1972 Addenda--of the ASME Code, Section III. This required the PSVs to be designed to open within ±1% of the set pressure. Currently, TSs also impose a tolerance of ±1% on the set pressure in the Limiting Condition for Operation (LCO) for the PSVs. However, the surveillance requirements of these TSs mandate testing the PSVs under Section XI of the ASME Code. Chapter 10 of the Code Of Federal Regulations, Part 50, requires that section XI testing be in compliance with the 1977 Edition, including the summer 1978 Addenda of the ASME code. This edition of Section

XI does not specify a tolerance to be applied to lift pressure verification; therefore, the tolerance prescribed in the LCO (±1%) is utilized as the acceptance criteria for Section XI testing.

The 1989 Edition of the ASME Code, Section XI, requires that the PSVs be tested per the standards in ASME/ANSI OM-1987, Part 1. These standards allow the tested lift pressure to exceed the stamped set pressure by up to 3% before declaring a test failure. Also, the 1989 Edition of the ASME Code, Section III, does not impose a set pressure tolerance on the design of the PSVs. The tolerance associated with the design of the valve can vary provided the licensing basis analysis supports it.

A safety evaluation was performed to verify that a set pressure tolerance of ±3% is bounded by the licensing basis analysis (See attached letters). Therefore, a tolerance of ±3% with respect to the PSV set pressure is consistent with the 1989 Edition of Sections III and XI, of the ASME Code.

The increase in the TS set pressure tolerance to ±3% would provide certain operational advantages. One advantage concerns the difficulty to ensure the PSVs are maintained within tolerance. A tolerance of ±1% is very difficult to ensure due to setpoint drift and uncertainties associated with the PSVs. Therefore, a tolerance of ±3% allows increased assurance of operability and is a somewhat more reasonable value. A second advantage to the increased tolerance is based on the ASME Code, Section XI, requirement to test additional valves when one of the valves in the sample group is found to be out of tolerance. A tolerance of ±3% is determined to be acceptable by the safety evaluation. This indicates that a tolerance of ±1% is conservative and unnecessary to maintain operability of the PSVs. Therefore, the testing of additional valves, due to being outside of the ±1% tolerance but inside ±3% tolerance, becomes counterproductive in that it increases the probability of extending the duration of an outage and requires additional manpower, planning and radiation exposure without necessarily increasing the level of safety.

The change in TSs to allow plant heatup from Mode 6 to Mode 3 with the PSVs cold set would allow PSVs to be tested and adjusted in place under actual operational conditions. Testing performed with the PSVs in place would enhance the reliability of the PSVs with respect to set pressure accuracy as well as reduce the time, manpower, and exposure currently used to remove, ship, test and reinstall the PSVs during Mode 6. An engineering evaluation of the licensing basis analysis shows that under certain conditions, and after extensive shutdowns, the licensing basis analysis remains valid even with all PSVs inoperable.

SAFETY EVALUATION

The following safety evaluation will demonstrate that the proposed changes do not present a compromise to safety. The evaluation will be addressed in two parts. The first part will pertain to the change in set pressure tolerance. The second part of the evaluation will be with respect to the change to allow testing of PSVs in Mode 3. Both changes are supported by individual 10CFR50.59 evaluations which are included in Attachment 4.

I

An evaluation was performed per 10CFR50.59 to support changing the PSV set pressure tolerance, as prescribed in TS, from ±1% to ±3%. This evaluation addressed the effects of the proposed change on LOCA and non-LOCA accidents, steam generator tube rupture (SGTR) event, and ASME Code requirements.

For the purposes of the evaluation, the lift setpoints are assumed to occur at 3% above and 3% below the lift setpoint currently in TSs. In addition, the accumulation point (pressure required for maximum flow to be achieved) is assumed to be 3% above the lift setpoint. This yields the following values:

TS Lift Setpoint = 2500 psia
Low Lift Setpoint = 2425 psia (TS value minus 3% tolerance)
High Lift Setpoint = 2575 psia (TS value plus 3% tolerance)
Accumulation Point = 2653 psia (TS value plus 3% tolerance plus 3% accumulation

Based on these assumptions, each non-LOCA licensing basis event was evaluated and the results were found to be acceptable for the proposed change. It is important to note that all LOCA events result in the depressurization of the RCS. Therefore, the PSVs are not challenged, thus rendering a change in PSV set pressure tolerance--a moot point with respect to LOCA events. The SGTR event also results in depressurization of the RCS and, therefore, is not affected by a change in PSV set pressure tolerance. It was also determined that with respect to the ASME Code, Sections III and XI, the PSVs are acceptable to be set and tested with a tolerance of ±3%.

The attached letter gives an item by item analysis of these evaluations. The letter also describes or references the methods and models used to complete these evaluations.

In conclusion, the impact on the licensing basis analyses of operation with the pressurizer safety valve lift setpoint tolerances increased from ±1% to ±3% has been examined. This examination has verified that operation with PSV setpoints within a ±3% tolerance about the nominal values will have no adverse impact upon the licensing basis analyses, as well as the steamline break mass and energy release rates inside and outside of containment. All licensing basis criteria continue to be met, and the conclusions in the Reload Transition Safety Report(RTSR) remain valid.

II

In order to facilitate rapid and accurate testing of the PSVs, it is desirous to perform the testing required by the ASME code, Section XI, in Mode 3. Currently all PSVs are required to be operable in Mode 3. The following evaluation will justify the acceptability of changing TS to allow having one or more PSVs inoperable in Mode 3 following a period of operation in Mode 5. This evaluation addresses LOCA, Non-LOCA and SGTR events as well as testing effects on the function of the PSVs.

The evaluation was done with respect to Mode 3 testing of PSVs using the methods of 10CFR50.59. The evaluation assumed the power operated relief valves were unavailable and also assumed the following plant conditions:

1) Mode 3 was achieved after at least five days of operation in Mode 5 or lower.

2) All RCCAs must be fully inserted with all CRDMs de-energized (rods in the tripped condition).

3) The pressurizer contains a steam bubble. (This is currently ensured by TS 3/4.4.3.)

Based on these assumptions, each Non-LOCA licensing basis event was evaluated and the results were found to be acceptable for the proposed change. It is noted that the SGTR event and all LOCA events result in RCS depressurization. Therefore, the proposed change does not impact those events since the events do not challenge the PSVs. The analysis on the effects of the testing device on the PSV indicated that the PSV would maintain its ability to function during testing and that testing would not impact plant operation in Mode 3.

The attached letter gives an item by item analysis of the evaluation. The letter also describes or references the methods and models used to complete the evaluation.

In conclusion, the impact of operation in Mode 3 with all PSVs inoperable for the purposes of testing has been examined. In order to support this operation, the reactor status must be maintained consistent with the assumptions made in the analysis. However, based on those assumptions, it has been verified that this operation will have no adverse impact on the licensing basis analysis. All licensing basis criteria continue to be met and the conclusions in the RTSR remain valid.

ATTACHMENT 3

DESCRIPTION OF AMENDMENT REQUEST

NO SIGNIFICANT HAZARDS EVALUATION

DESCRIPTION OF AMENDMENT REQUEST

Technical Specification (TS) 3/4.4.2 provides the basis for operation with respect to the pressurizer safety valves (PSVs). The PSVs operate to prevent the Reactor Coolant System (RCS) from being pressurized above its Safety Limit of 2735 psig.

TS 3/4.4.2.1, "Safety Valves-Shutdown," states that while in Modes 4 and 5, a minimum of one PSV is required to be operable. However, with no PSVs operable, the action statement allows continued operation in Modes 4 and 5, provided all positive reactivity changes are immediately suspended and an operable loop of RHR is placed into operation in the shutdown cooling mode. The relief capacity of a single safety valve is adequate to relieve any overpressure condition which could occur during shutdown. In the event that no safety valves are operable, an operating RHR loop connected to the RCS provides overpressure relief capability. This is due to the RHR suction relief valves serving as a portion of the Overpressure Protection System (TS 3/4.4.9.3) which provides a diverse means of overpressure protection when the RCS is below 300°F.

TS 3/4.4.2.2, "Safety Valves-Operating," states that while in Modes 1, 2 and 3, all PSVs are required to be operable. Also, if one PSV is inoperable, the action statement requires the restoration of all PSVs to operable status within 15 minutes or a plant shutdown is required. During operation, all PSVs must be OPERABLE to prevent the RCS from being pressurized above its safety limit of 2735 psig. The combined relief capacity of all of these valves is greater than the maximum surge rate resulting from a complete loss of load assuming no reactor trip until the first Reactor Protective System trip set point is reached (i.e., no credit is taken for a direct reactor trip on the loss of load) and also assuming no operation of the power operated relief valves or steam dump valves.

Both TSs require that the lift setting of the PSVs be 2485 psig ± 1% and that the surveillance requirements of TS 4.0.5 are met to determine operability.

This request is comprised of two basic changes. The first change is to increase the present lift setting tolerance of ±1% to ±3% for both TSs. The second change is to modify the TSs to allow plant heatup to Mode 3 with the PSVs setpoint adjusted under cold conditions (cold set). This requires modifying the surveillance requirement and eliminating the "*" note on TS 3.4.2.1 in addition to adding a note that exempts Mode 3 applicability under certain conditions on TS 3.4.2.2.

The PSVs were designed (i.e., manufactured) to meet the 1971 Edition--including the Winter 1972 Addenda--of the ASME Code, Section III. This required the PSVs to be designed to open within ±1% of the set pressure. Currently, TSs also impose a tolerance of ±1% on the set pressure in the Limiting Condition for Operation (LCO) for the PSVs. However, the surveillance requirements of these TSs mandate testing the PSVs under Section XI of the ASME Code. Chapter 10 of the Code Of Federal Regulations, Part 50, requires that section XI testing be in compliance with the 1977 Edition, including the summer 1978 Addenda of the ASME code. This edition of Section

XI does not specify a tolerance to be applied to lift pressure verification; therefore, the tolerance prescribed in the LCO (±1%) is utilized as the acceptance criteria for Section XI testing.

The 1989 Edition of the ASME Code, Section XI, requires that the PSVs be tested per the standards in ASME/ANSI OM-1987, Part 1. These standards allow the tested lift pressure to exceed the stamped set pressure by up to 3% before declaring a test failure. Also, the 1989 Edition of the ASME Code, Section III, does not impose a set pressure tolerance on the design of the PSVs. The tolerance associated with the design of the valve can vary provided the licensing basis analysis supports it.

A safety evaluation was performed to verify that a set pressure tolerance of ±3% is bounded by the licensing basis analysis (See attached letters). Therefore, a tolerance of ±3% with respect to the PSV set pressure is consistent with the 1989 Edition of Sections III and XI, of the ASME Code.

The increase in the TS set pressure tolerance to ±3% would provide certain operational advantages. One advantage concerns the difficulty to ensure the PSVs are maintained within tolerance. A tolerance of ±1% is very difficult to ensure due to setpoint drift and uncertainties associated with the PSVs. Therefore, a tolerance of ±3% allows increased assurance of operability and is a somewhat more reasonable value. A second advantage to the increased tolerance is based on the ASME Code, Section XI, requirement to test additional valves when one of the valves in the sample group is found to be out of tolerance. A tolerance of ±3% is determined to be acceptable by the safety evaluation. This indicates that a tolerance of ±1% is conservative and unnecessary to maintain operability of the PSVs. Therefore, the testing of additional valves, due to being outside of the ±1% tolerance but inside ±3% tolerance, becomes counterproductive in that it increases the probability of extending the duration of an outage and requires additional manpower, planning and radiation exposure without necessarily increasing the level of safety.

The change in TSs to allow plant heatup from Mode 6 to Mode 3 with the PSVs cold set would allow PSVs to be tested and adjusted in place under actual operational conditions. Testing performed with the PSVs in place would enhance the reliability of the PSVs with respect to set pressure accuracy as well as reduce the time, manpower, and exposure currently used to remove, ship, test and reinstall the PSVs during Mode 6. An engineering evaluation of the licensing basis analysis shows that under certain conditions and after extensive shutdowns, the licensing basis analysis remains valid even with all PSVs inoperable.

SIGNIFICANT HAZARDS EVALUATION

I

As a result of the evaluations performed with respect to PSV set pressure tolerance (see attached letters) it has been determined that no significant hazard consideration exists for the following reasons:

The proposed change does not represent a significant increase in the probability or consequences of an accident previously evaluated.

The PSVs provide protection from overpressurization of the primary system, and are actuated after an accident is initiated. However, the accidental depressurization of the RCS can be initiated by the opening of a PSV. Increasing the tolerance on these valves does not create a new failure mode or result in a lift setpoint that would increase the probability of an inadvertent opening of these valves. Also, as discussed in the evaluations, DNBR and PCT values affected by the non-LOCA and LOCA accident events remain within the limits specified in the licensing basis documentation. The evaluation also demonstrates that the mass/energy releases inside and outside the containment previously documented in the FSAR remain valid. In addition, the SGTR analyses show that the change in the pressurizer safety valve setpoint tolerance has no impact on the analysis. Therefore, the probability or consequences of an accident previously evaluated in the FSAR would not be increased due to changing the PSV lift setpoints by ±3% with respect to the current Technical Specification value.

The proposed change does not create a new or different kind of accident from any previously evaluated.

As previously stated, the PSVs provide overpressurization protection for the primary system. The analyses results as presented in the FSAR remain valid and no new failure mechanisms were determined. Thus, the possibility of an accident which is different than any already evaluated in the FSAR would not be created due to changing the PSV lift setpoints by ±3% with respect to the current Technical Specification value.

The proposed change does not represent a significant reduction in the margin of safety.

As indicated in the evaluation, the conclusions provided in the FSAR remain valid. All acceptance criteria continue to be met. Therefore, there is no reduction in the margin of safety defined in the bases to the Technical Specifications.

II

As a result of the evaluation performed to allow PSV testing in Mode 3 (see attached letter) it has been determined that no significant hazard consideration exists for the following reason:

<u>The proposed changes do not represent a significant increase in the probability or consequences of an accident previously evaluated</u>.

The installed SPVD does not restrict the vertical movement of the spindle before, during or after testing. The internal mechanism of the SPVD triggers a solenoid and releases the spindle allowing the valve to reseat. It is highly unlikely that the valve with the SPVD installed will fail in an open position, thus initiating a transient. Since the plant is in Mode 3, the plant is in a no load condition. Assuming that all rods are inserted and de-energized while the valves are being tested, no reactivity may be added to the primary through rod motion. Because of this, the PSVs are not required to mitigate any transient in Mode 3. In addition, all other safety systems used to mitigate any accidents postulated in Mode 3 are not affected. It has been demonstrated that the DNB and the PCT limits as defined in the FSAR remain applicable for Non-LOCA and LOCA postulated events. For the SGTR analysis, the core decay heat would be significantly less in Mode 3 and, therefore, the consequences are bounded by the results provided in the FSAR. Therefore, the probability or consequences of an accident previously evaluated in the FSAR will not be increased due the verification of the PSV setpoint values in Mode 3.

<u>The proposed change does not create a new or different kind of accident from any previously evaluated</u>.

All safety systems required in Mode 3 function, and no new failure modes are identified for any system or component, nor has any new limiting single failure been identified. Therefore, testing the PSVs in Mode 3 does not create the possibility of an accident which is different than any already evaluated in the FSAR.

<u>The proposed change does not represent a significant reduction in the margin of safety</u>.

The verification of the PSV setpoint values in Mode 3 does not restrict the valves from performing their intended function. All acceptance criteria continue to be met. Thus, there is no reduction in the margin of safety as defined in the bases to the Technical Specifications.

ATTACHMENT 4

SUPPORTING DOCUMENTS

First letter	10CFR50.59 evaluation supporting an increased Pressurizer Safety Valve set pressure tolerance of ± 3%.
Second letter	10CFR50.59 evaluation supporting the Relaxation of Technical Specifications for Pressurizer Safety Valves in Mode 3.

V.C. SUMMER NUCLEAR STATION

10 CFR 50.59 SAFETY EVALUATION ANALYSIS

FOR PRESSURIZER SAFETY VALVE SETPOINT

TOLERANCE RELAXATION TO ± 3%

VIRGIL C. SUMMER NUCLEAR STATION
10CFR50.59 EVALUATION ANALYSIS

Check Applicable Yes [ ] and No [ ] Indications

PARENT DOCUMENT TSP-880019

Does this modification change the Final Safety Analysis Report or Fire Protection Evaluation Report?

*1

Yes [ ]   No [✓]

TECH. SPEC. REFERENCE	
Section	Page
3.4.2.1	3/4 4-7
3.4.2.2	3/4 4-8

Not addressed in Tech Specs. [ ]

**FSAR/FPER REFERENCE		
Chapter	Section	Page
5	5.2.2	5.2-32,33

Not addressed in FSAR/FPER [✓]
(PRESSURIZER SAFETY VALVE TOLERANCES ARE NOT ADDRESSED IN THE FSAR/FPER)

Is a change in Tech. Specification involved?

*2

Yes [✓]   No [ ]

Nuc. Lic. Reviewer / Date

PSRC/NSRC Review

Request and Receive Nuclear Regulatory Commission Authorization For Change Prior To Implementation Of the Subject Change

Authorization Deleted

Abort Design Change

UNREVIEWED SAFETY QUESTION EVALUATION: Answer the following questions with a "yes" or "no", and provide specific reasons justifying the decision. (Attach additional sheets as required.)

1. Is the probability of an occurrence, the consequences of an accident, or malfunction of safety related equipment as previously evaluated in the FSAR/FPER increased?
   Yes [ ] No [✓]
2. Is the possibility of an accident or malfunction of a different type than any previously evaluated in the FSAR/FPER increased?
   Yes [ ] No [✓]
3. Is the margin of safety as defined in the basis for any Tech Spec. reduced?
   Yes [ ] No [✓]

~~SEE THE CONCLUSIONS OF THE ATTACHED EVALUATION~~ 5-11-90

SEE ATTACHED TWR FOR C.H. RICE, SERIAL 14992, TAB 1 DATED 5-11-90. 5/11/90

Any Answer Yes [ ]   All Answers No [✓]

*3

Authorization Received

Initiate Design Change

*If either answers (2) or (3) are "yes", then the change is submitted to the NRC under 10CFR50.59. If answer (1) is "yes" but answers (2) and (3) are "no", then the change is reportaable under 10CFR50.59b and a description of the change will be included in the Annual Report. All other changes are not reportable.

Lead Engineer — Date 5-8-90

Independent Reviewer (Level II) — Date 5-10-90

Associate Manager/Supervisor — Date 5/11/90

ENGINEERS

TECHNICAL WORK RECORD

Serial 14992

Engineer C. H. Rice

Date 5-11-90

Project Title 10CFR50.59 for TSP-880019 Tab 1 Page 1 of 1

The Unreviewed Safety Question Evaluation Questions are answered in the attached evaluation. The attached evaluation is an editorial compilation of the analyses and discussions contained in Westinghouse Safety Evaluations SECL 90-292 and SECL 89-1139. Although some editorial changes were required for this compilation, SECL 90-292 and SECL 89-1139 were combined without any changes, additions or deletions to their technical content. Therefore, the technical basis of the attached evaluation (and TSP-880019) is SECL 90-292 and SECL 89-1139.

INTRODUCTION

The V. C. Summer Technical Specifications currently require that the pressurizer safety valves (PSVs) be tested and verified to be operable within a ±1% tolerance about the nominal setpoint. This tolerance has been difficult to obtain due to setpoint drift and uncertainty, and is somewhat unrealistic. Therefore, South Carolina Electric & Gas (SCE&G) is requesting that the PSV tolerances be increased to ±3%.

LICENSING APPROACH AND SCOPE

The relaxation of the opening pressure of the PSV actual lift setpoints represents a departure from the normal plant configuration. This evaluation, although requiring a change to the Technical Specifications and a licensing amendment, will be performed using the method outlined under Chapter 10 of the Code of Federal Regulations, Section 50.59 (10CFR50.59). This method of evaluation will demonstrate that the proposed change represents no significant hazards consideration, as required by 10CFR50.91 (a) (1) and addresses the three test factors required by 10CFR50.92 (c).

EVALUATION

This evaluation examines the ±3% tolerance in the nominal PSV setpoint and assumes that the accumulation point occurs at a pressure which is 3% above the nominal valve lift setpoint. With these assumptions, the valve characteristics assumed in this evaluation are:

Nominal (Technical Specification) Lift Setpoint = 2500 psia
Low Lift Setpoint = 2425 psia (TS value minus 3% tolerance)
High Lift Setpoint = 2575 psia (TS value plus 3% tolerance)
Accumulation Point = 2653 psia (TS value plus 3% tolerance plus 3% accumulation)

Note that with a 3% reduction in the pressurizer safety valve setpoint, the lift setpoint remains above the PORV setpoint of 2350 psia. A reduction in the safety valve lift setpoint will result in a reduction in the actual relief capacity of the valve. A 3% reduction in the lift setpoint has been calculated to reduce the valve relief capacity to approximately 96% of its rated value. However, should the pressure reach the actual setpoint and rise to the 3% accumulation point, full rated relief capacity will be achieved.

Each non-LOCA licensing basis event is discussed below in the order in which it appears in the Reload Transition Safety Report (RTSR).

1. Uncontrolled Rod Cluster Control Assembly (RCCA) Bank Withdrawal from a Subcritical Condition

   For the Condition II event, rod withdrawal results in a rapid reactivity insertion and increase in core power potentially leading to high local fuel temperatures and heat fluxes with a reduction in the minimum DNBR. The transient is promptly terminated by a reactor trip on the Power Range High Neutron Flux low setpoint. Due to the inherent thermal lag in the fuel pellet, heat transfer to the RCS is relatively slow and the minimum DNBR is shown to remain above the limit value.

Generic analyses which take credit for the pressurizer safety valves opening with a nominal lift setpoint of 2500 psia demonstrate that the peak RCS pressure remains below 110% of design by showing that the pressure transient is bounded by the loss of load/turbine trip analysis. Plant specific analyses documented in the RTSR demonstrate that the DNBR licensing basis criteria are met. The DNB analysis conservatively does not take credit for the observed RCS pressure rise.

The pressurizer safety valves lifting at a setpoint 3% lower than nominal would be of benefit in reducing the severity of the pressure rise and the peak RCS pressure would continue to remain below 110% of design. In addition, the slightly reduced relief capacity of the safety valves discussed in the introduction would continue to be adequate to relieve overpressurization.

Should the PSV tolerance be increased, the rod withdrawal from subcritical pressure transient will continue to be bounded by the loss of load event which is discussed later.

Thus, the results of this analysis are unaffected by increasing the PSV setpoint tolerance to ±3%, and the conclusions in the RTSR remain valid.

2. Uncontrolled Rod Cluster Control Assembly (RCCA) Bank Withdrawal at Power (RTSR Section 15.2.2)

For this Condition II event, various initial power levels and reactivity insertion rates for both minimum and maximum feedback assumptions are analyzed. The resulting power excursion may lead to high local fuel temperatures and heat fluxes and a reduction in the minimum DNBR. Since this event is a limiting DNB event and not peak pressure limiting, the pressurizer power-operated relief valves (PORVs) are conservatively assumed to be operable.

The primary system pressure does not reach the reduced PSV setpoint during this event. Thus, the results of this analysis are unaffected by increasing the tolerance on the PSVs to ±3% and the conclusions in the RTSR remain valid.

3. Rod Cluster Control Assembly Misoperation (RTSR Section 15.2.3)

This condition II event is analyzed to demonstrate that following various RCCA misoperation events such as dropped rod(s)/bank or statically misaligned rods, that the minimum DNBR remains above the limit value. The primary system pressures do not reach the reduced PSV setpoint during this event. Thus, the results of this analysis are unaffected by increasing the tolerance on the PSVs to ±3% and the conclusions in the RTSR remain valid.

4. Uncontrolled Boron Dilution (RTSR Section 15.2.4)

This Condition II event is analyzed for all six modes of operation. The analysis demonstrates that sufficient negative reactivity exists such that, should a dilution event occur, there is sufficient time following an alarm to allow operator detection and termination of the event prior to a complete loss of shutdown margin and return to criticality. The Mode 1 dilution analysis is bounded by the RCCA withdrawal at power event while the Mode 2 dilution analysis continues to be bounded by the RCCA withdrawal at hot zero power. The PSV setpoint tolerance relaxation for these events has already been addressed. For the dilution analyses performed in Modes 3 through 6, since adequate operator action time is assured prior to reaching criticality, no additional heat is added to the core and no pressurization of the primary system occurs. Changes in the PSV setpoint tolerances will have no effect on the calculated available operator action time. Thus, the results of this analysis are unaffected by increasing the tolerance on the PSVs to ±3% and the conclusions in the RTSR remain valid.

5. Partial Loss of Forced Reactor Coolant Flow (RTSR Section 15.2.5)

This Condition II event is analyzed under full power conditions assuming that 1 of 3 operating reactor coolant pumps coasts down. The reactor is promptly tripped on low reactor coolant loop flow. The analysis demonstrates that the minimum DNBR remains above the limit value. The RCS pressure increases above the initial value during the event, yet never reaches the reduced PSV setpoint. Note that no credit is taken for the observed RCS pressure rise in the DNB analysis. Thus, the results of this analysis are unaffected by increasing the tolerance on the PSVs to ±3% and the conclusions in the RTSR remain valid.

6. Startup of an Inactive Reactor Coolant Loop (RTSR Section 15.2.6)

This Condition II event is analyzed assuming a maximum initial power level consistent with 2 loop operation and the P-8 setpoint. The startup of an inactive loop results in a reactivity insertion since the inactive loop fluid is at a lower temperature than the rest of the core. The analysis demonstrates that the minimum DNBR remains above the limit value. The RCS pressure increases above the initial value during the event yet never reaches the reduced PSV setpoint. Thus, the results of this analysis are unaffected by increasig the tolerance on the PSVs to ± 3% and the conclusions in the RTSR remain valid.

7. Loss of External Electrical Load and/or Turbine Trip (RTSR Section 15.2.7)

The analysis presented in the RTSR represents a complete loss of steam load from full power without a direct reactor trip. Four cases are analyzed--maximum and minimum feedback--with and without pressure control. The analysis demonstrates that, with the power mismatch between the core and turbine, the primary and secondary system pressures remain below 110% of design and that the minimum DNBR remains above the limit value.

A sensitivity analysis was performed using the LOFTRAN computer code assuming the PSV characteristics at the ±3% tolerance. The peak pressurizer pressure was calculated to be 2636 psia for the minimum feedback without pressure control case. Thus, the primary pressure continues to remain below 110% of design and the minimum DNBR continues to remain above the limit value.

Should the pressurizer safety valves lift at a setpoint 3% lower than nominal, the peak RCS pressure will continue to remain below 110% of design. In addition, the slightly reduced relief capacity at the lower lift setpoint will continue to be adequate to prevent overpressurization of the RCS. Of the four cases analyzed all but one results in increases in the DNBR. For the minimum DNBR case, the PORVs are assumed to be operable and the relief capacity is sufficient to prevent reaching the reduced safety valve setpoint.

Thus, the results of this analysis are unaffected by increasing the tolerance on the PSVs to ±3% and the conclusions in the RTSR remain valid.

8. Loss of Normal Feedwater (RTSR Section 15.2.8)

The analysis presented in the RTSR represents a complete loss of feedwater from full power. The loss of the secondary side heat sink results in a heatup and pressurization of the primary and secondary systems. The analysis demonstrates that adequate emergency feedwater flow is delivered to the steam generators to remove decay heat such that overpressurization will not occur and the pressurizer does not fill. This analysis conservatively assumes operation of the PORVs with a lift setpoint of 2350 psia to maximize the water surge into the pressurizer. The PORV capacity is adequate to limit the pressurization of the RCS and prevent actuation of the PSVs. The maximum pressurizer water volume was calculated to be 1375 cubic feet (total pressurizer volume is 1480 cubic feet including surge line), and the peak RCS pressure was found to be 2373 psia. Therefore, the analysis demonstrates that the primary system pressures remain below 110% of design pressure and that the pressurizer does not become water solid. Thus, the results of this analysis are unaffected by increasing the tolerance on the PSVs to ± 3% and the conclusions in the RTSR remain valid.

9. Loss of Offsite Power to the Station Auxiliaries (Station Blackout) (RTSR Section 15.2.9)

The analysis presented in the RTSR represents a complete loss of power to the plant auxiliaries, e.g., the reactor coolant pumps, condensate pumps, etc., from full power. The loss of power results in a heatup and pressurization of the primary and secondary systems. The analysis demonstrates that adequate emergency feedwater flow is delivered to the steam generators to remove decay heat such that DNB will not occur, overpressurization of the primary and secondary systems will not occur, and the pressurizer does not fill. This analysis conservatively assumes operation of the PORVs with a lift setpoint of 2350 psia to maximize the water surge into the pressurizer and minimize margin to DNB. The PORV capacity is adequate to prevent actuation of the PSVs. The maximum pressurizer water volume was calculated to be 1302 cubic feet (total pressurizer volume is 1480 cubic feet including surge line), and the peak RCS pressure was found to be 2373 psia. Therefore, the analysis demonstrates that the primary system pressure remains below 110% of design pressure, the DNBR remains above the limit value, and the pressurizer does not become water solid. Thus, the results of this analysis are unaffected by increasing the tolerance on the PSVs to ±3% and the conclusions in the RTSR remain valid.

10. Excessive Heat Removal Due to Feedwater System Malfunctions (RTSR Section 15.2.10)

    The analysis presented in the RTSR illustrates the plant response to a 250% step increase in the feedwater flow to one steam generator from full power, and a step increase in feedwater flow from zero to nominal full load flow to one steam generator at zero power. The analysis demonstrates that from zero power the reactivity transient, and thus the minimum DNBR, is bounded by the rod withdrawal from subcritical event. For the full power case, the minimum DNBR is shown to remain above the limit value. The RCS pressure increases above the initial value during the event, yet never reaches the reduced PSV setpoint. Thus, the results of this analysis are unaffected by increasing the tolerance on the PSVs to ±3% and the conclusions in the RTSR remain valid.

11. Excessive Load Increase Incident (RTSR Section 15.2.11)

    The analysis presented in the RTSR describes plant response to a 10% step increase in load. Four different cases are analyzed: minimum and maximum feedback, with and without reactor control. For each case it is shown that the minimum DNBR remains above the limit value. The cases which assume no reactor control result in an RCS depressurization as the heat extraction from the secondary side increases. The cases which take credit for reactor control maintain the RCS pressure at essentially the initial value. Thus, in no case does the RCS pressure reach the reduced PSV setpoint; hence, the results of this analysis are unaffected by increasing the tolerance on the PSVs to ±3% and the conclusions in the RTSR remain valid.

12. Accidential Depressurization of the Reactor Coolant System (RTSR Section 15.2.12)

    For this ANS Condition II event, the transient is initiated by the opening of a single pressurizer relief or safety valve at full power. Initially, the RCS pressure drops rapidly until pressure reaches the hot leg saturation pressure. At this time the pressure decrease continues, but at a slower rate. The analysis demonstrates that the minimum DNBR remains above the limit value. Since the RCS pressure drops immediately following initiation of the event, operation of the pressurizer safety valves is not required. Thus, the results of this analysis are unaffected by increasing the tolerance on the PSVs to ±3% and the conclusions in the RTSR remain valid.

13. Accidental Depressurization of the Main Steam System (RTSR Section 15.2.13)

For this ANS Condition II event, the transient is initiated by the full opening of a single steam dump, relief, or safety valve at zero power. The analysis confirms that the minimum DNBR remains above the limit value. Since the RCS pressure drops immediately following initiation of the event, the pressurizer safety valves are not actuated. Thus, the results of this analysis are unaffected by increasing the tolerance on the PSVs to ±3% and the conclusions in the RTSR remain valid.

14. Spurious Operation of the Safety Injection System at Power (RTSR Section 15.2.14)

For this ANS Condition II event, a spurious Safety Injection System (SIS) signal is assumed to be generated at full power. The injection of borated water into the RCS reduces core power, temperature and pressure until the reactor trips on low pressurizer pressure. Since the RCS and pressure drops immediately following initiation of the event, the pressurizer safety valves are not actuated. Thus, the results of this analysis are unaffected by increasing the tolerance on the PSVs to ±3% and the conclusions in the RTSR remain valid.

15. Minor Secondary Side Pipe Breaks (RTSR Section 15.3.2)

This ANS Condition II event continues to be bounded by the analysis presented in RTSR Section 15.4.2 (see items 19 and 20, below).

16. Inadvertent Loading of a Fuel Assembly Into An Improper Position (RTSR Section 15.3.3)

For the event presented in the RTSR, the loading of a fuel assembly into an improper position would affect the core power shape. Since the power shape and not the total power generated would be affected, the RCS conditions will remain unaffected such that the pressurizer safety valves would not be actuated. Thus, the results of this analysis are unaffected by increasing the tolerance on the PSVs to ±3% and the conclusions in the RTSR remain valid.

17. Complete loss of Forced Reactor Coolant Flow (RTSR Section 15.3.4)

This Condition III event is analyzed under full power conditions assuming that 3 of 3 operating reactor coolant pumps coast down. The reactor is assumed to trip on an undervoltage signal. The analysis demonstrates that the minimum DNBR remains above the limit value. The RCS pressure increases above the initial value during the event, yet never reaches the reduced PSV setpoint. Note that no credit is taken for the observed pressure rise in the DNB analysis. Thus, the results of this analysis are unaffected by increasing the tolerance on the PSVs to ±3% and the conclusions in the RTSR remain valid.

18. Single Rod Cluster Control Assembly (RCCA) Withdrawal at Full Power (RTSR Section 15.3.6)

For this Condition III event, two cases are analyzed and presented in the RTSR: automatic and manual reactor control. In both cases an increase in core power, coolant temperature and hot channel factor result in a reduction in the minimum DNBP. The analysis demonstrates that, although it is not possible for all cases to ensure that DNB will not occur, an upper bound on the number of fuel rods experiencing DNB is less than or equal to 5%. Since this event is a limiting DNB pressure event and not peak pressure limiting, credit is not taken for any pressure increase associated with this event. The primary system pressures do not reach the reduced PSV setpoint during this event. Thus, the results of this analysis are unaffected by increasing the tolerance on the PSVs to $\pm 3\%$ and the conclusions in the RTSR remain valid.

19. Rupture of a Main Steam Line (RTSR Section 15.4.2.1)

For this ANS Condition IV event the transient is assumed to be initiated by the instantaneous double-ended rupture of a main steam line. Since the RCS pressure drops immediately following initiation of the event, the pressurizer safety valves are not actuated. Thus, the results of this analysis are unaffected by increasing the tolerance on the PSVs to $\pm 3\%$ and the conclusions in the RTSR remain valid.

20. Rupture of a Main Feedwater Pipe (RTSR Section 15.4.2.2)

For this ANS Condition IV event, the double-ended rupture of a main feedwater pipe initially results in a cooldown of the RCS due to the heat removal of the steam generator blowdown. This cooldown period is followed by a heatup as the high levels of decay heat and the lack of inventory on the secondary side results in inadequate heat transfer. The event is analyzed to show that adequate heat removal capability exists to remove core decay heat and stored energy following a reactor trip from full power and that the core remains in a coolable geometry. This is accomplished by applying the strict criterion that no hot leg boiling occurs during the transient. For this event, the pressurizer safety valves are actuated during the heatup phase following reactor trip.

A sensitivity analysis has been performed using the LOFTRAN code, assuming the pressurizer safety valve characteristics are increased by the +3% tolerance. The maximum RCS system pressure was calculated to be 2596 psia. In addition, the minimum subcooling margin in the RCS was found to be 23.5°F. Thus, the analysis shows that the primary system is not overpressurized, and no boiling occurs in the hot leg of the RCS.

Should the pressurizer safety valve setpoint be reduced by up to 3%, the primary side pressure would be reduced throughout the transient by approximately 3% when compared to the analysis documented in the RTSR. The reduced RCS pressure will tend to reduce the available margin to the hot leg boiling acceptance criteria. However, Westinghouse has performed sensitivity studies (see Reference 8) which show that the reduced RCS pressures allow a greater safety injection flow into the RCS. The increased SI flow serves to cool the RCS resulting in an increase in the margin to the hot leg boiling criteria from that observed in the RTSR analysis. Adequate relief capacity is available to ensure that the RCS pressure will not be overpressurized.

Thus, the results of this analysis show that increasing the tolerance on the PSVs to ±3% will not cause overpressurization of the primary system or boiling in the RCS hot leg as a consequence of a main feedwater pipe rupture. Therefore, the conclusions of the RTSR remain valid.

21. Single Reactor Coolant Pump Locked Rotor (RTSR Section 15.4.4)

This Condition IV event is analyzed under full power conditions assuming the instantaneous seizure of 1 RCP rotor. This results in a rapid RCS flow reduction and pressure rise, and possible DNB. The reactor is promptly tripped on a low flow signal. The analysis demonstrates that no more than 15% of the rods experience DNB and that the RCS peak pressure remains below that which would cause stresses to exceed the faulted condition stress limits. The DNB analysis conservatively takes no credit for the pressure rise during the locked rotor event and, thus, is not impacted by any change in the pressurizer safety valve setpoint.

A sensitivity analysis has been performed using the LOFTRAN code assuming the PSV characteristics are increased by the +3% tolerance. The maximum RCS pressure is calculated to be 2648 psia. This is below that pressure which would cause stresses to exceed the faulted condition stress limits.

Furthermore, with a 3% reduction in the safety valve setpoint, the peak RCS pressures would be reduced from those calculated in the RTSR analysis. The slight reduction in the safety valve relief capacity associated with the lift setpoint reduction will not significantly effect the ability of these valves to mitigate the RCS pressurization transient.

Thus, for pressurizer safety valve tolerances of ±3%, the analysis shows that the primary system is not overpressurized, and the conclusions in the RTSR remain valid.

22. Rupture of a Control Rod Drive Mechanism Housing (RTSR Section 15.4.6)

For this Condition IV event, a rapid reactivity insertion and increase in core power leads to high local fuel and clad temperatures and possible fuel and/or clad damage. Four cases are analyzed: beginning and end of life, hot zero and hot full power. The analysis shows that the fuel and clad limits discussed in RTSR Section 15.4.6 are not exceeded and that the peak RCS pressure does not exceed the faulted condition stress limits.

As documented in WCAP-7588 Revision 1-A, a detailed calculation of the pressure surge for an extremely conservative ejected rod worth of 1.5 dollars at BOL, hot full power conditions, indicates that the peak RCS pressure is limited to 2800 psia. This analysis assumes that the pressurizer safety valve lift setpoint is 2500 psia. A 3% reduction in the pressurizer safety valve setpoint from 2500 psia to 2425 psia will serve to reduce the peak RCS pressure from that documented in WCAP-7588 Revision 1-A by approximately 3%. Thus, the peak RCS pressure will continue to remain below the faulted condition stress limits. The slight reduction in the safety valve relief capacity at the lower setpoint discussed previously will not reduce the overall capability of the PSVs to limit the overpressurization.

An increase in the pressurizer safety valve setpoint from 2500 psia to 2575 psia will not increase the calculated peak pressure by more than the setpoint increase (75 psi) since the relief capacity of these valves is not reduced. Thus, even under extremely conservative assumptions, the peak pressure will remain under 2900 psia. This pressure does not exceed that which would cause stresses to exceed the faulted condition stress limits.

Thus, for pressurizer safety valve tolerances of ±3%, the analysis shows that the primary system is not overpressurized, and no boiling occurs in the RCS hot leg. Therefore, the conclusions in the RTSR remain valid.

23. Steamline Break Mass/Energy Release - Inside/Outside Containment

Various steam line break cases are analyzed for the purposes of generating mass and energy release rates which are then applied to containment response or compartment environmental analyses. Cases are performed, assuming various break sizes and initial power levels. For small breaks occurring at high power levels, it is possible that pressurization of the primary and secondary systems may occur. Specifically, if the energy release through the break is less than the decay heat energy deposition into the RCS, pressurization may occur possibly to the point of safety valve actuation. However, since the relief capacity of the PSVs is undiminished there is sufficient capacity to prevent overpressurization of the primary system and raising the PSV setpoints will have no impact upon the mass and energy releases previously calculated. In addition, reductions in the PSV lift setpoints will serve to reduce the primary side temperatures and energy release rates.

Thus, for pressurizer safety valve tolerances of ±3%, there is no adverse impact upon the mass and energy releases previously calculated. Therefore, the conclusions in the FSAR remain valid.

<u>LOCA</u>

It can be stated here--to alleviate repetition--that none of the LOCA-related analyses require the PSV to successfully recover from the accident. Loss of Coolant Accidents result in a primary side depressurization due to the loss of fluid. Since the Reactor Coolant System is depressurizing, the PSVs are not challenged. Therefore, changes to the PSVs setpoint tolerances will not effect the LOCA-related analysis results.

STEAM GENERATOR TUBE RUPTURE

The FSAR analysis for a steam generator tube rupture (SGTR) is performed to evaluate the radiological consequences due to the SGTR event. The major factors that affect the radiological consequences for an SGTR are the amount of radioactivity in the reactor coolant, the amount of reactor coolant transferred to the secondary side of the affected steam generator through the ruptured tube, and the amount of steam released from the ruptured steam generator to the atmosphere.

An SGTR results in a decrease in pressurizer pressure due to the loss of reactor coolant inventory, and reactor trip and SI actuation were assumed to occur as a result of low pressure for the V. C. Summer SGTR analysis. A loss of offsite power was also assumed to occur at the time of reactor trip and, thus, the steam dump system was assumed not to be available. The energy transfer from the primary system following reactor and turbine trip causes the secondary side pressure to increase rapidly after reactor trip until the steam generator power operated relief valves (PORVs) and/or safety valves lift to dissipate the energy. For the SGTR analysis in the V. C. Summer FSAR, it is assumed that the secondary pressure is maintained at the lowest secondary safety valve setpoint following reactor trip. After reactor trip and SI initiation, the RCS pressure was assumed to reach equilibrium at the point where the incoming SI flowrate equals the outgoing break flowrate, and the equilibrium pressure and break flowrate were assumed to persist until 30 minutes after the accident.

The reactor coolant activity assumed for the SGTR analysis in the V. C. Summer FSAR is based on 1% fuel defects and is assumed to be independent of the transient condition and, thus, would not be affected by the changes in the pressurizer safety valve setpoint tolerances. Since the pressurizer pressure decreases following a SGTR, the pressurizer safety valves will not be actuated for this event. Therefore, the changes in the setpoint tolerance for the pressurizer safety valves would not affect the V. C. Summer SGTR analysis.

Based on the above information, it is concluded that the changes in the pressurizer safety valve setpoint tolerances would not adversely affect the V. C. Summer SGTR analysis.

VALVE EVALUATION

The three pressurizer safety relief valves supplied to V. C. Summer are Crosby model 6M6 Style HB-BP-86 valves manufactured to drawing DS-C-56964-1 with a set pressure of 2485 psig. The applicable ASME Section III Code for design of these valves is the 1971 Edition, including Winter 1972 Addenda, which specifies an opening pressure tolerance of plus or minus one percent of set pressure. Additionally, these valves are currently under the jurisdiction of ASME Section XI which specifies the inservice inspection requirements.

This safety evaluation will address compliance of the new opening pressure tolerance of plus three or minus three percent to ASME Section III and XI.

The three pressurizer safety valves have been reconciled to be in compliance with the 1989 ASME Code Section III, Subarticle NB-7410, which states that "the set pressure of at least one of the pressure relief devices connected to this system shall be not greater than the Design Pressure of any component within the pressure retaining boundary of the protected system" (in this case 2485 psig). The code allows setting the valves within the tolerance band around the nominal setting of 2485 psig, provided the licensing basis analysis results support it. Therefore, the increase in the opening pressure tolerance can be tolerated from a Section III standpoint since the licensing basis analysis has been evaluated and it has shown that the licensing basis criteria are still met.

The pressurizer safety valves are in compliance with the 1989 ASME Code Section XI, Subarticle IWV-1100, which requires that inservice valve testing be performed in accordance with ASME/ANSI OM (Part 1 and Part 10). The pressurizer safety valves are used in steam service; therefore, the requirements for inservice testing must meet ASME/ANSI OM-1987, Part 1, Section 8.1 (Reference 9). V. C. Summer has complied with the inservice testing requirements by testing the valves at as-installed steam and ambient air temperatures with the valves thermally stabilized.

Paragraph 1.3.3.1(e)(2) of ASME/ANSI Om-1987, Part 1, states that "any valve exceeding its stamped set pressure by 3% or greater shall be repaired or replaced, the cause of failure shall be determined and corrected, and the valve shall successfully pass a retest before it is returned to service." To be in compliance with this paragraph, the valve's tolerance should be just under the upper tolerance of plus 3% and not be at exactly plus 3%. Furthermore, upon set pressure verification any valve found with a set pressure greater than or equal to the plus 3% should be reset to within the ±3% tolerance.

The three pressurizer safety valves at V. C. Summer are acceptable to be set with an opening pressure tolerance of ±3%, based on the reconciliation of the ASME Code Section III, and the actual test methods used by SCE&G to meet the inservice inspections requirements of ASME Code, Section XI.

CONCLUSIONS

The impact on the licensing basis analyses of operation with the pressurizer safety valve lift setpoint tolerance increased from ±1% to ±3% has been examined. In support of this evaluation, some sensitivity analyses, as well as the evaluation of existing analyses, has been performed. These analyses and evaluations have assumed that the PSV lift setpoint tolerances are increased to ±3%. It was further assumed that the valves have reached the full open (accumulation point) at a pressure 3% higher than the assumed lift setpoint (nominal lift setpoint plus 3%).

Based on the evaluations and analyses performed, it has been concluded that operation with PSV setpoints within a ±3% tolerance about the nominal values will have no adverse impact upon the licensing basis analyses, as well as the steamline break mass and energy release rates inside and outside of containment. All licensing basis criteria continue to be met and the conclusions in the RTSR remain valid.

Unreviewed Safety Question Evaluation Question 1

The PSVs provide protection from overpressurization of the primary system and are actuated after an accident is initiated. The accidental depressurization of the RCS event can be initiated by the opening of a PSV. Increasing the tolerance on these valves does not create a new failure mode or result in a lift setpoint that would increase the probability of an inadvertent opening of these valves. Therefore, the probability of an accident previously evaluated in the FSAR would not be increased due to increasing or decreasing the PSV lift setpoints by 3% around the current Technical Specification values.

As discussed above, DNBR and PCT values affected by the Non-LOCA and LOCA accidents events remain within the limits specified in the licensing basis documentation. It has been demonstrated that the mass/energy releases inside and outside the containment previously documented in the FSAR remain valid. In addition, a review of the SGTR analyses shows that the proposed changes to the PSV setpoint tolerance have no impact on the analysis. Therefore, the calculated offsite doses currently presented in the FSAR remain applicable for this condition.

The three pressurizer safety valves at V. C. Summer are acceptable to be set with an opening pressure tolerance of ±3% based on the reconciliation of the ASME Code, Section III, and the actual test methods used by SCE&G to meet the inservice inspections requirements of ASME Code Section XI. Therefore, the probability of a malfunction of equipment important to safety previously evaluated in the FSAR would not be increased due to increasing or decreasing the PSV lift setpoints by 3% around the current Technical Specification values.

As discussed above, DNBR and PCT values affected by the Non-LOCA and LOCA accident events remain within the limits specified in the licensing basis documentation. It has been demonstrated that the mass/energy releases inside and outside the containment previously documented in the FSAR remain valid. In addition, a review of the SGTR analyses show that the proposed changes to the pressurizer safety valve setpoint tolerance will not affect the V. C. Summer SGTR analysis. This change does not impact the ability of any other safety system from performing its intended safety function. Therefore, consequences of a malfunction of equipment important to safety previously evaluated in the FSAR remain applicable for this condition.

Unreviewed Safety Question Evaluation Question 2

As previously stated, the PCVs provide overpressurization protection for the primary system. The analyses results as presented in the FSAR remain valid and no new failure mechanisms were determined. Thus, the possibility of an accident which is different than any already evaluated in the FSAR would not be created due to increasing or decreasing the PSV lift setpoints by 3% around the current Technical Specification values.

As previously stated, the three pressurizer safety valves at V. C. Summer are acceptable to be set with an opening pressure tolerance of ±3%, based on the reconciliation of the ASME Code, Section III, and the actual test methods used by SCE&G to meet the inservice inspection requirements of ASME Code Section XI. The analyses results as presented in the FSAR remain valid and no new failure mechanisms were determined. Thus, the possibility of a malfunction of equipment important to safety different than any already evaluated in the FSAR would not be created due to increasing or decreasing the PSV lift setpoints by 3% around the current Technical Specification values.

Unreviewed Safety Question Evalaution Question 3

As indicated in the above evaluation, the conclusions provided in the FSAR remain valid. All acceptable criteria continue to be met. Therefore, there is no reduction in the margin of safety defined in the bases to the technical specifications.

REFERENCES

1. SECL 90-292, Westinghouse Safety Evaluation for Changing Pressurizer Safety Valve Setpoint Tolerance (addresses change to +3% -1%).

2. SECL 89-1139, Westinghouse Safety Evaluation Supplement to SECL 90-292 (upgrades evaluation to support change to ±3%).

3. SECL 89-939, Westinghouse Safety Evaluation, Pressurizer/Main Steam Safety Valve Setpoint Tolerance Relaxation.

4. Westinghouse Letter, CGE-90-591 from J. C. Snelson to A. R. Koon, Jr., dated April 12, 1990, re: "Pressurizer Safety Valve Setpoint Tolerance Questions."

5. Final Safety Analysis Report for the Virgil C. Summer Nuclear Station.

6. WCAP-10266-P-A Rev. 2, The 1981 Version of the Westinghouse ECCS Evaluation Model Using the BASH Code, MY Young, et. al., March 1987.

7. WCAP-10054-P-A, Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code, N Lee, et. al., August 1985.

8. WCAP-9230, Report on the Consequences of a Postulated Main Feedline Rupture.

9. ASME/ANSI OM-1987, Part 1, titled Requirements for Insevice Performance Testing of Nuclear Power Plant Pressure Relief Devices.

10. ASME/ANSI OMa-1988 Part 10, titled Inservice Testing of Valves in Light Water Reactor Power Plants Addenda to ASME/ANSI OM-1987.

11. Vantage 5 Reload Transition Safety Report for the Virgil C. Summer Nuclear Station, September 1988.

SECL NO. 90-271

Customer Reference No(s) ____________

Westinghouse Reference No(s) ____________

WESTINGHOUSE
NUCLEAR SAFETY EVALUATION CHECK LIST

1) NUCLEAR PLANT(S) Virgil C. Summer

2) CHECK LIST APPLICABLE TO: Relaxation of Pressurizer Safety
(Subject of Change) Valves Tech Specs for Testing during Mode 3

3) The written safety evaluation of the revised procedure, design change or modification required by 10CFR50.59(b) has been prepared to the extent required and is attached. If a safety evaluation is not required or is incomplete for any reason, explain on page 2.

Parts A and B of this Safety Evaluation Check List are to be completed only on the basis of the safety evaluation performed.

CHECK LIST - PART A - 10CFR50.59(a)(1)

(3.1) Yes___ No X A change to the plant as described in the FSAR?
(3.2) Yes___ No X A change to procedures as described in the FSAR?
(3.3) Yes___ No X A test or experiment not described in the FSAR?
(3.4) Yes X No___ A change to the plant technical specifications? (See note on page 2.)

4) CHECK LIST - PART B - 10CFR50.59(a)(2) (Justification for Part B answers must be included on page 2.)

(4.1) Yes___ No X Will the probability of an accident previously evaluated in the FSAR be increased?
(4.2) Yes___ No X Will the consequences of an accident previously evaluated in the FSAR be increased?
(4.3) Yes___ No X May the possibility of an accident which is different than any already evaluated in the FSAR be created?
(4.4) Yes___ No X Will the probability of a malfunction of equipment important to safety previously evaluated in the FSAR be increased?
(4.5) Yes___ No X Will the consequences of a malfunction of equipment important to safety previously evaluated in the FSAR be increased?
(4.6) Yes___ No X May the possibility of a malfunction of equipment important to safety different than any already evaluated in the FSAR be created?
(4.7) Yes___ No X Will the margin of safety as defined in the bases to any technical specification be reduced?

If the answers to any of the above questions are unknown, indicate under 5.) REMARKS and explain below.

If the answer to any of the above questions in Part A (3.4) or Part B cannot be answered in the negative, based on written safety evaluation, the change review would require an application for license amendment as required by 10CFR50.59(c) and submitted to the NRC pursuant to 10CFR50.90.

5) REMARKS:

The following summarizes the justification upon the written safety evaluation,(1) for answers given in Part A (3.4) and Part B of this SECL:

See attached safety evaluation.

(1) Reference to document(s) containing written safety evaluation: ____________________

FOR FSAR UPDATE

Section: NONE Page(s): NONE Table(s): NONE Figure(s): NONE

Reason for/Description of Change:

No FSAR changes required

SAFETY EVALUATION APPROVAL LADDER:

Prepared by (Nuclear Safety): John E. Schulz Date: 5/2/90

Reviewed by (Nuclear Safety): M J Romano Date: 5/3/90

Nuclear Safety Group Manager: R.J. Sterdis Date: 5/3/90

Relaxation of Pressurizer Safety Valves Tech Specs for Testing during Mode 3

1.0 INTRODUCTION

Section XI of the ASME Boiler and Pressure Vessel Code states that safety valves which have been repaired must be tested prior to return to service. This testing is done in order to ensure proper lift setpoint and relief capacity. Additionally, it is required that the test be performed with the same medium and the same environmental conditions as seen during normal operation. In order to facilitate a rapid and accurate testing of the pressurizer safety valves, personnel at the V. C. Summer plant wish to perform these tests while in Mode 3.

Testing of the safety valves is done using the Crosby Gage & Valve Set Point Verification Device (SPVD). The SPVD is an air assist device which is physically mounted on the safety valve to be tested. The air assist device is used to jack the valve 0.040 inches open. A remote computer simultaneously measures the system pressure, the load required to lift the valve, and the amount of lift to determine the actual setpoint. Upon obtaining a predetermined amount of lift (0.040 inches or less), the air assist device is immediately released, allowing the valve to close.

The purpose of the pressurizer safety valves is to ensure that the primary side pressure does not exceed pre-defined limits. These limits are separated into several categories depending upon the classification of the licensing basis event being analyzed. As noted in the Standard Review Plan (NUREG-0800), the pressure of the reactor coolant and main steam systems should be maintained below 110% of the design pressure for Condition I, II, and III events and below 120% of design pressure for Condition IV events. With all pressurizer safety valves inoperable, the ability of the plant to relieve any pressure build up is severely reduced and may be effectively eliminated. Note that, for the purposes of this evaluation, it is assumed that all power operated relief valves are unavailable.

Currently, the Technical Specifications for the V. C. Summer unit require that in Modes 1, 2, and 3, the pressurizer safety valves are operable. South Carolina Electric & Gas (SCE&G) desires to change this requirement such that, while in Mode 3 only, operation with one or more of the pressurizer safety valves inoperable may continue for the purposes of testing these valves, provided that this testing is performed following a period of operation in Mode 5.

2.0 Non-LOCA Evaluation

The safety evaluation presented below examines the impact on the non-LOCA licensing basis analyses of operation in Mode 3 with all pressurizer safety valves inoperable. In order to support this operation, several assumptions must be made regarding reactor status and operation. These assumptions are:

a) Testing of the safety valves in Mode 3 will only take place after at least 5 days of operation in cold shutdown (Mode 5) or a lower mode, after which the RCS will be brought to Mode 3 where safety valve testing may proceed.

b) With the safety valves inoperable in Mode 3, all RCCAs must be inserted with all control rod drive mechanisms (CRDMs) de-energized (rods placed in the trip condition).

c) With the safety valves inoperable in Mode 3, a steam bubble must be present in the pressurizer.

Each non-LOCA licensing basis event is discussed below in the order in which it appears in the RTSR.

1. Uncontrolled Rod Cluster Control Assembly (RCCA) Bank Withdrawal from a Subcritical Condition (RTSR Section 15.2.1)

For this Condition II event, rod withdrawal results in a rapid reactivity insertion and increase in core power leads to high local fuel temperatures and heat fluxes and a reduction in DNBR. The transient is promptly terminated by a reactor trip on the Power Range High Neutron Flux - low setpoint. Due to the inherent thermal lag in the fuel pellet, heat transfer to the RCS is relatively slow and the minimum DNBR is shown to remain above the limit value. Generic analyses which take credit for the pressurizer safety valves demonstrate that the peak RCS pressure remains below 110% of design. However, assuming all safety valve testing will be performed while operating with all rods inserted and de-energized, RCCA withdrawal due to electrical or mechanical malfunctions or operator error is precluded. Therefore, no energy may be added to the primary or secondary side through rod motion. Thus, with the assumptions above satisfied, the results of this analysis are unaffected by inoperable pressurizer safety valves while in Mode 3 and the conclusions in the RTSR remain valid.

2. Uncontrolled Rod Cluster Control Assembly (RCCA) Bank Withdrawal at Power (RTSR Section 15.2.2)

For this Condition II event, various initial Mode 1 power levels and reactivity insertion rates for both minimum and maximum feedback assumptions are analyzed. The resulting power excursion may lead to high local fuel temperatures and heat fluxes and a reduction in the minimum DNBR. However, the potential impact of rod motion with inoperable safety valves while in Mode 3 is addressed above (see item 1). Thus, the results of this analysis are unaffected by inoperable safety valves in Mode 3 and the conclusions in the RTSR remain valid.

3. Rod Cluster Control Assembly Misoperation (RTSR Section 15.2.3)

This Condition II event is analyzed in Mode 1 to demonstrate that following various RCCA misoperation events such as dropped rods/banks or statically misaligned rods, that the minimum DNBR remains above the limit value. However, assuming all safety valve testing will be performed while in Mode 3 with all rods inserted and de-energized, RCCA misoperation while at power is precluded. Thus, the results of this analysis are unaffected by inoperable safety valves in Mode 3 and the conclusions in the RTSR remain valid.

4. Uncontrolled Boron Dilution (RTSR Section 15.2.4)

This Condition II event is analyzed for all six modes of operation. The analysis performed under Mode 3 conditions demonstrates that sufficient negative reactivity exists, such that, should a dilution event occur, sufficient time exists following an alarm on high flux at shutdown to allow operator detection and termination of the event prior to a complete loss of shutdown margin. However, since the reactor remains subcritical throughout the dilution event, no additional heat is added to the core and no pressurization of the primary system occurs. Thus, the results of this analysis are unaffected by inoperable safety valves in Mode 3 and the conclusions in the RTSR remain valid. However, during testing of the pressurizer safety valves, the operator should be specifically alert for this type of transient since operator action is the only means of resolution.

5. Partial Loss of Forced Reactor Coolant Flow (RTSR Section 15.2.5)

This Condition II event is analyzed under full power conditions assuming that 1 of 3 operating reactor coolant pumps coasts down. The reactor is promptly tripped on low reactor coolant loop flow. The analysis demonstrates that the minimum DNBR remains above the limit value. However, while in Mode 3 there is no power generation. Also, as discussed earlier, since the reactor will have been in a cold shutdown condition for at least 5 days prior to entering Mode 3 where safety valve testing may be done, only minimal levels of decay heat will be present. Should an operating RCP lose power and coastdown while in Mode 3, the remaining operating RCP as well as natural circulation flow in the RCS will be adequate to preclude DNB and adequate heat transfer to the secondary side water inventory will prevent pressurization of the primary and secondary systems. Thus, the results of this analysis are unaffected by inoperable safety valves in Mode 3 and the conclusions in the RTSR remain valid.

6. Startup of an Inactive Reactor Coolant Loop (RTSR Section 15.2.6)

This Condition II event is analyzed assuming a maximum initial power level consistent with 2 loop operation and the P-8 setpoint. In the RTSR analysis, the startup of the inactive loop results in a reactivity insertion since the inactive loop fluid is at a lower temperature than the rest of the core. In Mode 3, all coolant loops are at the same temperature (V. C. Summer has no loop stop valves) so that startup of an inactive loop will not result in a reactivity insertion and the resulting power excursion. However, upon startup of an RCP, there will be an initial pressure surge throughout the RCS. The maintenance of a steam bubble in the pressurizer during safety valve testing will ensure that the RCS can "absorb" the pressure increase without overpressurization. The magnitude of this pressure increase may be seen in RTSR Figure 15.2.6-3 which shows that, even at full power the pressure rise is not sufficient to reach the PORV setpoint. Thus, while subcritical in Mode 3 overpressurization will not occur. Thus, the results of this analysis are unaffected by inoperable safety valves in Mode 3 and the conclusions in the RTSR remain valid.

7. Loss of External Electrical Load and/or Turbine Trip (RTSR Section 15.2.7)

The analysis presented in the RTSR represents a complete loss of steam load from full power without a direct reactor trip. Credit is taken for operation of the main steam safety valves and the pressurizer power operated relief valves. The analysis demonstrates that, with the power mismatch between the core and turbine, the primary and secondary system pressures remain below 110% of design and that the minimum DNBR remains above the limit value. Under Mode 3 conditions no steam load is present, and the turbine is not operating. Thus, this analysis is unaffected by inoperable safety valves in Mode 3 and the conclusions in the RTSR remain valid.

8. Loss of Normal Feedwater (RTSR Section 15.2.8)

The analysis presented in the RTSR represents a complete loss of feedwater from full power. The loss of the secondary side heat sink results in a heatup and pressurization of the primary and secondary systems. The analysis demonstrates that adequate emergency feedwater flow is delivered to the steam generators to remove decay heat such that overpressurization will not occur and the pressurizer does not fill. While in Mode 3, the secondary side inventory is maintained, as necessary by operation of the emergency feedwater system. Should emergency feedwater flow be interrupted while in Mode 3, there would be an adequate secondary side water inventory to remove the low levels of decay heat present in the RCS for a significant period of time. However, if necessary, alternate modes of pressure relief (e.g., MSSVs) are available if needed. Thus, this analysis is unaffected by inoperable safety valves in Mode 3 and the conclusions in the RTSR remain valid.

9. Loss of Offsite Power to the Station Auxiliaries (Station Blackout) (RTSR Section 15.2.9)

The analysis presented in the RTSR represents a complete loss of power to the plant auxiliaries, i.e., the reactor coolant pumps, condensate pumps, etc., from full power. The loss of power results in a heatup and pressurization of the primary and secondary systems. The analysis demonstrates that adequate emergency feedwater flow is delivered to the steam generators to remove decay heat such that DNB will not occur, overpressurization of the primary and secondary systems will not occur, and the pressurizer does not fill. While in Mode 3, should a loss of offsite power cause a loss of forced reactor coolant flow adequate heat removal from the fuel will be provided by natural circulation. Additionally, sufficient secondary side water inventory will be available to ensure that the primary and secondary sides will not become overpressurized. However, if necessary, alternate modes of pressure relief (e.g., MSSVs) are available if needed. Thus, this analysis is unaffected by inoperable safety valves in Mode 3 and the conclusions in the RTSR remain valid.

10. Excessive Heat Removal Due to Feedwater System Malfunctions (RTSR Section 15.2.10)

The analysis presented in the RTSR illustrates the plant response to a 250% step increase in the feedwater flow to one steam generator from both zero and full power. The RTSR analysis demonstrates that from zero power the reactivity transient is bounded by the rod withdrawal from subcritical event. For the full power case, the minimum DNBR remains above the limit value.

While in Mode 3, the secondary side inventory is maintained by the emergency feedwater system. Shoud EFW flow increase with the reactor subcritical in Mode 3, the RCS temperature would be reduced which in the presence of a negative MTC would result in the addition of positive reactivity. The reactivity added to the core due to the reduced primary temperature would remain bounded by the rod withdrawal from subcritical analysis presented in the RTSR; therefore, the DNB transient is unaffected. The addition of excessive EFW flow to the SGs would initially result in a depressurization of the RCS until sufficient reactivity is added and the core becomes critical. At this point in the transient the results are conservatively bounded by the credible steamline break event discussed later in this evaluation. Thus, this analysis is unaffected by inoperable safety valves in Mode 3 and the conclusions in the RTSR remain valid.

11. Excessive Load Increase Incident (RTSR Section 15.2.11)

The analysis presented in the RTSR describes plant response to a 10% step increase in load. Four different cases are analyzed: minimum and maximum feedback, with and without reactor control. For each case it is shown that the minimum DNBR remains above the limit value. However, in Mode 3 the plant is in a no load condition and no means through which the turbine load may be increased. Thus, this analysis is unaffected by inoperable safety valves in Mode 3 and the conclusions in the RTSR remain valid. Note that, increases in steam flow due to pipe breaks are discussed in RTSR Section 15.2.13 (see item 13 below).

12. Accidental Depressurization of the Reactor Coolant System (RTSR Section 15.2.12)

For this ANS Condition II event, the transient is initiated by the opening of a single pressurizer relief or safety valve at full power. Initially the RCS pressure drops rapidly until pressure reaches the hot leg saturation pressure. At this time the pressure decrease continues but at a slower rate. Secondary side pressure is essentially unaffected during this transient. The analysis demonstrates that the minimum DNBR remains above the limit value. Since RCS pressure drops from the initiation of the event, operation of the pressurizer safety valves is not required. Should a pressurizer relief or safety valve fully open while in Mode 3 a similar pressure transient would be seen. Therefore, inoperable safety valves in Mode 3 will not affect the results of this analysis and the conclusions of the RTSR will remain valid. Note that the safety valve test procedure to be used opens the safety valve, at least partially, and will result in some RCS depressurization. However, due to the level of core subcriticality and the low level of decay heat, the test circumstances are less limiting than those of the licensing basis analysis.

13. Accidental Depressurization of the Main Steam System (RTSR Section 15.2.13)

For this ANS Condition II event, the transient is initiated by the full opening of a single steam dump, relief, or safety valve. Since both the RCS and steam system pressures drop immediately following initiation of the event, the pressurizer safety valves are not actuated. Therefore, inoperable pressurizer safety valves in Mode 3 will not affect the results of this analysis and the conclusions of the RTSR will remain valid.

14. Spurious Operation of the Safety Injection System at Power (RTSR Section 15.2.14)

For this ANS Conditon II event, a spurious Safety Injection System (SIS) signal is assumed to be generated at full power. The injection of borated water into the RCS reduces core power, temperature and pressure until a reactor trip on low pressurizer pressure. The power and temperature reduction causes a similar reductions on the secondary side. Should a spurious SIS signal occur while in Mode 3, the injection of borated water would not result in a power reduction since the core is initially subcritical at zero power. The SI flow will tend to increase primary pressure; however, maintenance of a steam bubble in the pressurizer will ensure that the primary pressure rise will be sufficiently slow so that operator termination of SI will maintain pressure below 110% of design. Additionally, as the relatively cold SI water is injected into the RCS, the primary temperature will tend to be reduced resulting in some coolant shrinkage. Thus, inoperable pressurizer safety valves in Mode 3 will not affect the results of this analysis and the conclusions of the RTSR will remain valid. However, since continued operation of the safety injection system would eventually result in filling the pressurizer and pressurizing the RCS, operator action is required to terminate SI flow prior to the pressurizer going water solid or overpressurizing the RCS.

15. Minor Secondary Side Pipe Breaks (RTSR Section 15.3.2)

This ANS Condition II event continues to be bounded by the analysis presented in RTSR Section 15.4.2 (see items 19 and 20, below).

16. Inadvertent Loading of a Fuel Assembly Into An Improper Position (RTSR Section 15.3.3)

For the event presented in the RTSR, the loading of a fuel assembly into an improper position would affect the core power shape. Since the power shape and not the total power generated would be affected, the RCS conditions would remain unaffected such that the pressurizer safety valves would not be actuated. However, while in Mode 3 the core remains subcritical and no power generation occurs. Thus, the results of this analysis are unaffected by inoperable safety valves in Mode 3 and the conclusions in the RTSR remain valid.

17. Complete Loss of Forced Reactor Coolant Flow (RTSR Section 15.3.4)

This Condition II event is analyzed under full power conditions assuming that 3 of 3 operating reactor coolant pumps coasts down. The reactor is assumed to trip on an undervoltage signal. The analysis demonstrates that the minimum DNBR remains above the limit value. However, while in Mode 3 there is no power generation. Also, as discussed earlier, since the reactor will have been in a cold shutdown condition for at least 5 days prior to entering Mode 3 where safety valve testing may be done, only minimal levels of decay heat will be present. Should all operating RCPs lose power and coastdown, natural circulation flow in the RCS as well as the secondary side water inventory will be adequate to prevent pressurization of the primary and secondary systems. Thus, this analysis is unaffected by inoperable safety valves in Mode 3 and the conclusions in the RTSR remain valid.

18. Single Rod Cluster Control Assembly (RCCA) Withdrawal at Full Power (RTSR Section 15.3.6)

For this Condition III event, two cases are analyzed and presented in the FSAR: automatic and manual reactor control. In both cases an increase in core power, coolant temperature and hot channel factor result in a reduction in the minimum DNBR. The analysis demonstrates that, although it is not possible for all cases to ensure that DNB will not occur, an upper bound on the number of fuel rods experiencing DNB is less than or equal to 5%. However, the potential impact of rod motion with inoperable safety valves while in Mode 3 is addressed above (see item 1). Thus, the results of this analysis are unaffected by inoperable safety valves in Mode 3 and the conclusions in the RTSR remain valid.

19. Rupture of a Main Steam Line (RTSR Section 15.4.2.1)

For this ANS Condition IV event, the transient is assumed to be initiated by the instantaneous double-ended rupture of a main steam line. Since both the RCS and steam system pressures drop immediately following initiation of the event, the pressurizer safety valves are not actuated and the inoperability of the pressurizer safety valves will not affect the results of this analysis. It may also be noted that, with all RCCAs inserted into the core, no asymmetrical reactivity or power distribution effects would be observed, and thus, the minimum DNBR would remain above the limit value. Therefore, this event is unaffected by inoperable safety valves in Mode 3 and the conclusions of the RTSR remain valid.

20. Rupture of a Main Feedwater Pipe (RTSR Section 15.4.2.2)

For this ANS Condition IV event, the double-ended rupture of a main feedwater pipe initially results in a cooldown of the RCS due to the heat removal of the steam generator blowdown. This cooldown period is followed by a heatup as the high levels of decay heat and the lack of inventory on the secondary side results in inadequate heat transfer. The event is analyzed to show that adequate heat removal capability exists to remove core decay heat and stored energy following a reactor trip from full power and that the core remains in a coolable geometry. This is accomplished by applying the strict criterion that no hot leg boiling occurs during the transient. For this event, both the pressurizer and main steam safety valves are actuated during the heatup phase following reactor trip. Should a feedwater line break occur while in Mode 3, the primary side would initially experience a cooldown similar to that shown in the RTSR. However, since there is no significant power generation in the core and a low level of decay heat, adequate heat transfer capability would be present in the two intact steam generators and no heatup and pressurization phase would occur. Thus, this event is unaffected by inoperable safety valves in Mode 3 and the conclusions of the RTSR remain valid.

21. Single Reactor Coolant Pump Locked Rotor (RTSR Section 15.4.4)

This Condition IV event is analyzed under full power conditions assuming the instantaneous seizure of 1 RCP rotor. This results in a rapid RCS flow reduction and possible DNB. The reactor is tripped on a low flow signal. The analysis demonstrates that no more than 15% of the rods experience DNB. However, while in Mode 3 there is no power generation. Also, as discussed earlier, since the reactor will have been in a cold shutdown condition for at least 5 days prior to entering Mode 3 where safety valve testing may be done, only minimal levels of decay heat will be present. Should 1 operating RCP rotor lock, the remaining operating RCP as well as natural circulation flow in the RCS as well as the secondary side water inventory will be adequate to prevent overpressurization of the primary and secondary systems. Thus, this event is unaffected by inoperable safety valves in Mode 3 and the conclusions in the RTSR remain valid.

22. Rupture of a Control Rod Drive Mechanism Housing (RTSR Section 15.4.6)

For this Condition IV event, a rapid reactivity insertion and increase in core power leads to high local fuel and clad temperatures and possible fuel and/or clad damage. Four cases are analyzed: beginning and end of life, hot zero and hot full power. As previously discussed, since all safety valve testing will be performed in Mode 3 with all rods inserted and de-energized, should an RCCA be ejected it will not result in the core reaching criticality. Note that even with the most reactive RCCA stuck in the fully withdrawn position an ejected rod will not result in the core going critical. This is confirmed as part of each reload safety evaluation (i.e., the core will remain subcritical with N-2 rods inserted). Therefore, no energy may be added to the primary or secondary side due to the ejection of an RCCA. Thus, this analysis is unaffected by inoperable safety valves in Mode 3 and the conclusions in the RTSR remain valid.

23. Steamline Break Mass/Energy Release - Inside/Outside Containment

Various steam line break cases are analyzed for the purposes of generating mass and energy release rates which are then applied to containment response or compartment environmental analyses. Although cases are performed assuming various break sizes and initial power levels, for all breaks occuring from zero power conditions which are of concern here, both the primary and secondary sides experience a depressurization throughout the duration of the event. Therefore, the pressurizer safety valves are not actuated. Thus, the mass and energy releases previously calculated are unaffected by inoperable safety valves in Mode 3 and the conclusions of the RTSR remain valid.

3.0 LOCA Evaluation

It is noted that none of the LOCA-related analyses require the pressurizer safety valves to recover from an accident, thus relaxing the pressurizer safety valve technical specification has no effect on the LOCA-related analyses.

4.0 Steam Generator Tube Rupture Evaluation

The FSAR analysis for a steam generator tube rupture (SGTR) is performed to evaluate the radiological consequences due to the SGTR event. The major factors that affect the radiological consequences for an SGTR are the amount of radioactivity in the reactor coolant, the amount of reactor coolant transferred to the secondary side of the affected steam generator through the ruptured tube, and the amount of steam released from the ruptured steam generator to the atmosphere.

The SGTR analysis in the Summer FSAR was performed for full power operating conditions (Mode 1) since the results are assumed to be bounding for the lower operating modes. This assumption is primarily based on the fact that the core decay heat following a SGTR would be significantly less for the lower operating modes, which would result in a lower calculated steam release from the ruptured steam generator. Thus, the consequences of a SGTR in Mode 3 are expected to be bounded by the FSAR analysis provided that the key assumptions used for the analysis remain valid. The reactor coolant activity assumed for the Summer SGTR analysis is based on 1% fuel defects and is assumed to be independent of the transient conditions, and thus would remain valid. Since the pressurizer pressure decreases for a SGTR, the pressurizer safety valves are not challenged for this event. Thus, operation with the pressurizer safety valves inoperable would not have any effect on the SGTR analysis.

5.0 Pressurizer Safety Valve Evaluation

The testing of the safety valves using the Crosby Gage & Valve Set Point Verification Device (SPVD) is acceptable during Mode 3 with respect to the relieving function of the valves assuming no seismic events. The SPVD does not restrict vertical movement of the spindle, thus the valve will open, if subjected to a pressure transient and perform its relieving function with the SPVD installed. During the actual SPVD test, air is introduced into the diaphram head which produces the force necessary to lift the valve spindle. During this millisecond time frame the set pressure is determined, the solenoid in the SPVD vents and the valve closes. It is highly unlikely that the valve with the SPVD installed will fail in an open position, thus initiating a transient. SCE&G should review the test procedures to assure that the probability of initiating a transient is not increased.

Furthermore, upon entering into Mode 3, it is expected that the valves, although in a pretest condition, will open at the pressure set pressure previously defined and operated in Mode 1. Therefore, while the safety valve set pressure may be higher or lower than the nominal value, the valves will still function to limit pressure on the primary systems. Thus, credit can be taken for the operation of these valves prior to setpoint verification if needed to mitigate any accident postulated in Mode 3.

6.0 CONCLUSION

The impact of operation in Mode 3 with all pressurizer and main steam safety valves inoperable for the purposes of testing these valves has been examined. In order to support this operation, several assumptions must be made regarding reactor status and operation. These assumptions are:

a) Testing of the safety valves in Mode 3 will only take place after at least 5 days of operation in cold shutdown (Mode 5) or a lower mode, after which the RCS will be brought to Mode 3 where safety valve testing may proceed.

b) With the safety valves inoperable in Mode 3, all RCCAs must be inserted with all control rod drive mechanisms (CRDMs) de-energized (rods placed in the trip condition).

c) With the safety valves inoperable in Mode 3, a steam bubble must be present in the pressurizer.

Based on the evaluations performed, the following is concluded by Westinghouse.

As previously stated, the installed SPVD does not restrict the vertical movement of the spindle before, during or after testing. The internal mechanism of the SPVD triggers a solenoid and releases the spindle allowing the valve to reseat. It is highly unlikely that the valve with the SPVD installed will fail in an open position, thus initiating a transient. It is assumed that the test procedures assure that the probability of initiating a transient is not increased.

Therefore, the impact of the verification of the safety valve setpoint values in Mode 3 will not increase in the probability of an accident previously evaluated in the FSAR.

Since the plant is in Mode 3, the plant is in a no load condition. Assuming that all rods are inserted and de-energized while the valves are being tested, no reactivity may be added to the primary side through rod motion. Because of this, the pressurizer safeties are not required to mitigate any transient in Mode 3. In addition, all other safety systems used to mitigate any accidents postulated in Mode 3 are not affected. It has been demonstrated that the DNB and the PCT limits as defined in the FSAR remain applicable for Non-LOCA and LOCA postulated events. For the SGTR analysis, the core decay heat would be significantly less in Mode 3 and therefore, the consequences are bounded by the results provided in the FSAR. Therefore, the consequences of an accident previously evaluated in the FASR will not be increased due the verification of the safety valve setpoint values in Mode 3.

Since all safety systems required in Mode 3 function, and no new failure modes identified for any system or component nor has any new limiting single failure been identified, the possibility of an accident which is different than any already evaluated in the FSAR will not be created.

Upon entering into Mode 3, it is expected that the valves, although in a pretest condition, will open at the pressure setpoint previously defined and operated in during Mode 1. Therefore, while the safety valve setpoints may vary from the nominal, the valves will still function to limit pressure on the primary system. Thus, the probability of a malfunction of equipment important to safety previously evaluated in the FSAR will not increase due to operation of these valves prior to setpoint verification if needed to mitigate any accident postulated in Mode 3.

The consequences of a malfunction of equipment important to safety previoulsy evaluated in the FSAR will not increase due to the verification of the safety valve setpoint values in Mode 3. As previously stated, it is expected that the valves, although in a pretest condition, will open at the pressure setpoint previously defined and operated in during Mode 1 and will continue to perform their intended function and thus, there is no impact on the safety analysis. The conclusions in the FSAR regarding radiological consequences remain applicable.

The possibility of a malfunction of equipment important to safety different from that already evaluated in the FSAR will not be created due the verification of the safety valve setpoint values in Mode 3.

As previously stated, the installed SPVD does not restrict the vertical movement of the spindle before, during or after testing. The internal mechanism of the SPVD triggers a solenoid and releases the spindle allowing the valve to reseat. It is highly unlikely that the valve with the SPVD installed will fail in an open position, thus initiating a transient.

The verification of the safety valve setpoint values in Mode 3 does not restrict the valves from performing their intended function. All acceptance criteria continue to be met. Thus, there is no reduction in the margin of safety defined in the bases to the technical specification.

Therefore, the verification of the safety valve setpoint values in Mode 3 at Virgil C. Summer do not adversely affect the safe operation of the plant and as such, do not represent an unreviewed safety safety question as defined in the criteria of 10CFR 50.59 (A) (2).

7.0 REFERENCES

1. Final Safety Analysis Report for the Virgil C. Summer Nuclear Station.

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