VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

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United States Nuclear Regulatory Commission
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Gentlemen:

**VIRGINIA ELECTRIC AND POWER COMPANY**
**NORTH ANNA POWER STATION UNIT NOS. 1 AND 2**
**SUMMARY OF FACILITY CHANGES, TESTS AND EXPERIMENTS**

Pursuant to 10 CFR 50.59 (d)(2), enclosed is a summary description of facility changes, tests and experiments, including a summary of the regulatory/safety evaluations, that were implemented at North Anna Power Station during 2001.

If you have any questions, please contact us.

Very truly yours,

DAH

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Enclosures

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IE47

## SAFETY EVALUATION LOG
## SPECIAL TESTS
## 2001

| S.E. # | Unit | Document | System | Description | SNSOC Date |
|---|---|---|---|---|---|
| 01-SE-ST-01 | 1,2 | 0-ST-79 | | "Auxiliary Building Filter Bank Acceptance Tests" | 3-09-01 |
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**01-SE-ST-01**

**Description**

Revision 0 to 0-ST-79, "Auxiliary Building Filter Bank Acceptance Tests"

This Special Test ensures that the Auxiliary Building filter banks (1-HV-FL-3A & 1-HV-FL-3B) will provide adequate filtration at design conditions, by performing the filter acceptance testing specified in sections 8 & 9 of ANSI N510-1975. Specifically, the following tests will be performed: a) airflow distribution test, b) air-aerosol mixing uniformity test, and c) pressure drop test.

**Summary**

**BACKGROUND**

Plant Issue N-2000-0695 states that detailed acceptance tests of the Auxiliary Building filter banks (1-HV-FL-3A & 1-HV-FL-3B) were required by sections 8, 9, 10 & 12 of ANSI N510-1975, but there is no confirmation that acceptance testing of these filters was performed at the design flow rates.

The Primary Ventilation System provides a filtration function during and following accidents. Without confirmation that acceptance testing of these filters was performed, the primary ventilation system may not be able to provide the required degree of filtration. Revision 1 of JCO C-98-01 identifies resolution of plant issue N-2000-0695 as a required corrective action before closing out the JCO. The required compensatory action associated with this JCO is to maintain ECCS leakage within an administrative limit of 600 cc/hour for total ECCS leakage per unit. This is controlled by 1&2-GOP-8.2. With this limit, both onsite and offsite dose will be within licensing basis limits, even if all ventilation is unfiltered. Therefore, with this JCO in place, the filter banks are not required for any post-accident filtration function.

**PROPOSED ACTIVITY**

0-ST-79 is a Special Test designed to verify that the Auxiliary Building filter banks (1-HV-FL-3A & 1-HV-FL-3B) will provide adequate filtration at design conditions, by performing the filter acceptance testing specified in sections 8 & 9 of ANSI N510-1975. Section 8 specifies an airflow capacity verification, an airflow distribution test and a pressure drop test; section 9 specifies an air-aerosol mixing uniformity test. Note that sections 10 & 12 of ANSI N510-1975 specify in-place leak testing of the filter banks which is performed by periodic test procedures (1-PT-77.2 & 77.3 currently, and future 0-PT-77.14A & 14B for testing at the required post-accident flow rate). The special test is required to allow JCO C-98-01 to be closed. The special test performs the following activities for one filter bank at a time:

- First, a visual inspection is performed of the filter banks, similar to that done by existing surveillance tests. Then the filter design maximum flow rate of approximately 39,200-cfm is aligned through one filter bank.
- The first test verifies that there is adequate flow distribution within the housing across the inlet to the HEPA/pre-filters. There are adjustable flow distribution blades installed for this purpose where the suction duct enters the filter housing. Air distribution is measured at both the design maximum filter flow rate and at the minimum expected post-accident flow rate.
- The next test verifies that injection ports and sample ports are located so as to provide adequate mixing of the aerosol in the air approaching the HEPA/pre-filters.
- The third test verifies that the fans can operate under actual field conditions at the maximum filter pressure drop of 5" wg, based on TSCR #377A.
- These tests are then repeated for the other filter bank. Finally, the test is secured and the system is re-aligned to its normal configuration.

Personnel safety while taking measurements inside the filter housing is addressed by requiring confined space entry precautions in accordance with VPAP-1904. The filter bank being tested will be considered inoperable but available, and the action of TS 3.7.8.1 will be entered.

**FAILURE MODES**

With inadequate airflow distribution within the filter, or with inadequate sample port locations, the filter may not be providing its design filtration efficiencies. These conditions are acceptable since the filter banks are not required for any post-accident filtration function with JCO C-98-01 in place. Also, during the special test the flow rate may be up to 10% above the design maximum of 39,200 cfm. The potentially high flow rate will only affect filter residence time and will not physically damage the filter banks. In

addition, in the event of a Unit trip or ESF actuation, the test will be aborted, and existing EOPs ensure that the post-LOCA ventilation configuration will be aligned with flow through the Auxiliary Building Filters. To ensure ventilation equipment is not damaged during pressure drop testing, steps within the procedure require the filter pressure drop to be monitored while it is increased gradually, and require independent verification that all plastic has been removed following testing.

**UNREVIEWED SAFETY QUESTION DETERMINATION**

Operation of the ventilation system as proposed by this Special Test creates no unique precursors or precursor events for Chapter 15 accidents. The proposed Special Test does not change the intended operation of the charcoal filter bank or equipment required for accident mitigation. This Special Test may be aborted at any time as directed by the Shift Supervisor based on Unit operating conditions (for example, Unit Trip or ESF actuation). No changes will be made to the Operating License or Tech Specs. Appendix R and the environment will also not be impacted by this Special Test. For these reasons, an unreviewed safety question does not exist.

**SAFETY EVALUATION LOG**
**TEMPORARY MODIFICATIONS**
**2001**

| S.E. # | Unit | Document | System | Description | SNSOC Date |
|---|---|---|---|---|---|
| 01-SE-TM-01 | 2 | N2-1137 | DA | Allows testing of the incore sump high level switch 2-DA-LS-206 because annunciator 2J-C8 is locked in. | 1-12-01 |
| 01-SE-TM-02 | 2 | N2-1138 | DA | Defeats the hi-hi alarm for 2-DA-LS-206 (which is locked in), restoring annunciator 2J-C8 to a condition to alert the operator to a high level in the incore room sump. | 1-12-01 |
| 01-SE-TM-03 | 1 | N1-1694 | SW | A ground was discovered on the positive lead (black) of the PI circuit, causing indication failure of 1-SW-PI-110, 1-SW-P-4 discharge header pressure transmitter. This TM swaps leads to allow the ground to be transferred to the negative (white) side of the circuit to restore the circuit to a functional condition. | 2-08-01 |
| 01-SE-TM-04 | 2 | N2-1140 | | Temporarily removes coil wires #73 from both bridge 4A relays for polar crane 2-MH-CRN-1 because 1 wire is sticking & the operator has no bridge speed control. | 4-04-01 |
| 01-SE-TM-05 | 1,2 | N1-1695<br>N2-1139<br>1-PT-71.1Q (OTO)<br>2-PT-71.1Q (OTO)<br>ET N-00-134<br>WO 447260-01, 02<br>WO 447261-01, 02 | FW | Temporarily replaces the 1st orifice (1-FW-RO-102A & 2-FW-RO-202A) in the full flow recirc line for each turbine driven AFW pump with a replacement orifice sized to limit pump discharge to about 345 gpm. Data will be collected for design input to a DCP (REA R1996-503) that will permanently replace the existing 1st orifices. | 4-12-01 |
| 01-SE-TM-06 | 2 | N2-1141<br>2-AR-T-C2<br>VPAP-1403 | | Lift leads from 2-GM-LS-210-2 to clear a locked-in defoaming tank level alarm (2T-C2) on the turbine supervisory panel in the MCT (2-EI-CB-10) with no high oil level condition present. | 5-10-01 |
| 01-SE-TM-07 | 2 | N2-1142 | | The leads for seal leakoff temperature element (2-CH-TE-2126) & pump radial bearing temperature element (2-CH-TE-2125) for U2 "C" RCP need to be swapped at Junction Box JB-781-2 for these parameters to indicate correctly on the P-250. | 5-10-01 |
| 01-SE-TM-08 | 1 | TM N1-1697 | | Main turbine speed pickup #4 has failed & cannot be repaired until the next outage. The failed speed sensor provides a start permissive to bearing lift pump 1-GM-P-10. Use of a spare speed input will allow the lift pump control to be returned to AUTO & restore turbine speed indication to the turbine supervisory panel. | 5-17-01 |
| 01-SE-TM-09 | 2 | TM N2-1143 | | Installs a video camera & associated equipment to observe oil level in the lower oil reservoir for the 2-RC-P-1A motor. | 6-08-01 |
| 01-SE-TM-10 | 1 | TM N1-1696 | GM | Lifts leads at 1-GM-TS-102B to disable the input to annunciator K-B7, which has been alarming prior to the setpoint of 175°F & periodically causes annunciator K-B7 to lock in on hot days. | 6-12-01 |
| 01-SE-TM-11 | 1,2 | TM N1-1698 | BC | Installs a temporary chemical addition system to the BC system in order to add Calgon biocide H-900 in tablet form | 6-14-01 |

**SAFETY EVALUATION LOG**
**TEMPORARY MODIFICATIONS**
**2001**

| S.E. # | Unit | Document | System | Description | SNSOC Date |
|---|---|---|---|---|---|
| 01-SE-TM-12 | 2 | TM N2-1144 | RC | Installs an electrical jumper between terminals 2-15 & 2-16 of junction box RCPV 16B to disable the U2 control room annunciator 2C-F1 | 6-15-01 |
| 01-SE-TM-13 | 2 | N2-1145 | CD | Defeats the mechanical chiller 2-CD-MR-1 compressor high thrust bearing oil temperature trip due to the chiller tripping with normal bearing oil temperature | 6-21-01 |
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**01-SE-TM-01**

**Description**
Temporary Modification (TM ) N2-1137
Allow testing of the incore sump high level switch (2-DA-LS-206).

**Summary**
The Incore Sump Level alarm (2J-C8) is comprised of a Hi and then a Hi-Hi alarm corresponding to sump levels of 18" and 20" respectively. These two alarms are actuated by two different level electrodes. The 18" high electrode provides the level control for the incore instrumentation sump and at 18" will open contact (B) (12050-TLD-DA-09) in level switch 2-DA-LS-206 to actuate the Hi level alarm and will close contact (A) in the switch to start the incore instrument room sump pump, 2-DA-P-5. The 20" electrode provides the Hi-Hi level alarm only and will close contact (C) in the level switch at 20" to reflash the Hi/Hi-Hi level alarm. The pump stops and the alarm clears when level reaches the setpoint of a third probe (6" Unit 1 electrode, 8" Unit 2 electrode).

Annunciator 2J-C8 (Incore Inst. Room Sump Hi/Hi-Hi Level alarm) was received and remained locked in. The hathaway system was tested and it was determined that the Hi-Hi portion of the field circuit was causing the alarm. However, it is not clear that an actual high level condition exists since there is no level indication for the incore sump. To ensure the Hi-Hi level alarm is due to an erroneous signal and not actual incore sump level, this Temporary Modification (TM) will install a jumper from contact C01 to C00 (12050-ESK-6GD) to defeat the 2-DA-P-5 high sump level interlock, allowing the pump to be manually started with a sump level less than 18". This jumper will ensure the pump will operate on a valid Hi level signal and will verify the operability of the 18" electrode.

This jumper will also bypass the high level start permissive. The pump will be run manually for only 30 seconds with this TM installed. The TM will be removed thereafter and the Hi Level start permissive will be restored. This TM will also allow the pump to be run with less than 8" in the sump and the pump could be run in a dry condition. For the short duration of this pump run, no damage to the pump is expected to occur. This TM will be installed only long enough to test the validity of the Hi/Hi-Hi level alarm and will then be removed. Prior to installing the jumper, the breaker for 2-DA-P-5 will be opened to ensure the pump does not prematurely start and run longer than necessary. Once the jumper is installed, the breaker will then be closed and the pump started and run until one of the following occurs:

(a) The containment sump level stops increasing (the incore sump pump discharges to the containment sump),
(b) The incore sump Hi/Hi-Hi level alarm (2J-C8) clears, or
(c) 30 seconds passes with no change in the containment sump level

This Temporary Modification should be allowed for the following reasons:

1) The safety significance of this Hi-Hi alarm is minimal. Reactor Coolant leakage limitations are listed in Tech Spec 3.4.6.2. and leakage detection systems required are listed in 3.4.6.1. The leakage detection systems are Containment gaseous and particulate radiation monitors and the containment sump level and discharge flow measurement system. The Incore sump level indication is not a part of the Safety Analysis system required to monitor for increased RCS leakage.
2) The UFSAR also takes no credit for the sump level indication in Section 5.2.4.1, 'Leakage Detection'. The UFSAR credits the following systems for monitoring for RCS leakage: Containment gaseous rad monitor, Containment particulate rad monitor, Containment Structure leakage monitoring system, Containment recirculation system cooler heat load, Containment Sump monitoring and the RCS makeup rate. Again, the Incore sump is not included in the group of essential leakage indications.
3) The Incore Sump level alarm is a good indicator to have available and this TM will ensure that the Hi level portion of the alarm which is still operating properly.
4) The margin of safety of the Tech Specs (containment leakage) is based on early detection of leakage and is consistent with Reg Guide 1.45, May 1973. Threshhold values are as low as possible based on industry

experience yet not too low to unnecessarily restrict operation. The restoration of this system which is not even taken credit for in the Safety Analysis only serves to improve the margin of safety with regard to RCS leakage.

5) Testing the validity of the Hi/Hi-Hi alarm will not increase the probablity of occurence, the consequences or the possibility of a different type of accident since no credit is taken for this function in the Tech. Specs. or UFSAR. There is no increased risk of a small break LOCA as a result of this TM.

No Technical Specifications require change by implementing the TM. This TM is beneficial in that one portion of the alarm will be restored for use by the operator. For these reasons no unreviewed safety question is created by this TM for the Hi/Hi-Hi alarm on Incore Sump Level and the TM should be installed.

**01-SE-TM-02**

**Description**

Temporary Modification # N2-1138

The HI-Hi alarm for the Incore Room Sump Level is alarming spuriously (2-DA-LS-206). The high alarm for the Incore Room Sump level remains operable as does the operation of the sump pump.

**Summary**

The Incore Sump Level alarm (2J-C8) is comprised of a Hi and then a Hi-Hi alarm corresponding to sump levels of 18" and 20" respectively. These two alarms are actuated by two different electrodes. The 18" high electrode provides the level control for the incore instrunmentation sump and at 18" will open contact 'B' (12050-TLD-DA-09) in level switch 2-DA-LS-206 to actuate the Hi level alarm and will close contact 'A' in the switch to start the Incore Instrument Room Sump Pump, 2-DA-P-5. The 20" electrode provides the Hi-Hi level alarm only and will close contact 'C' in the level switch at 20" to reflash the Hi/Hi-Hi level alarm. The sump pump stops and the alarm clears when level reaches the setpoint of a third probe (6" Unit 1 electrode, 8" Unit 2 electrode). The 2-DA-LS-206 level switch is sending an erroneous signal to indicate a sump level of 20". This Temporary Modification will disable this erroneous signal and restore the Control Room annunciator to a non-alarming condition until an actual Hi level of 18 inches is reached in the sump. This Temporary Modification should be allowed for the following reasons:

1) The safety significance of this Hi-Hi alarm is minimal. Reactor Coolant leakage limitations are listed in Tech Spec 3.4.6.2. and leakage detection systems required are listed in 3.4.6.1. The leakage detection systems are Containment gaseous and particulate radiation monitors and the containment sump level and discharge flow measurement system. The Incore sump level indication is not a part of the Safety Analysis system required to monitor for increased RCS leakage.

2) The UFSAR also takes no credit for the sump level indication in Section 5.2.4.1, 'Leakage Detection'. The UFSAR credits the following systems for monitoring for RCS leakage: Containment gaseous rad monitor, Containment particulate rad monitor, Containment Structure leakage monitoring system, Containment recirculation system cooler heat load, Containment Sump monitoring and the RCS makeup rate. Again, the Incore sump is not included in the group of essential leakage indications.

3) The Incore Sump level alarm is a good indicator to have available and this TM will restore that portion of the alarm which is still operating properly, the Hi level alarm. By disabling the Hi-Hi alarm, the original intent of the alarm is restored by alerting the OATC to an unusual condition with the audible and visual alarm from Annunciator 2J-C8 when sump level reaches 18". Allowing the Hi-Hi alarm to remain in (flashing) with the audible alarm acknowledged establishes a degree of complacency on the part of the operator regarding an alarm which is constantly present and this should be avoided.

The TM does not introduce an Unreviewed Safety Question for the following reasons:

The incore sump Hi-Hi level alarm does not contribute to the initiation of any analyzed acidents. The 20" level electrode provides input to the Hi-Hi level alarm only and provides no other function. Removing the input from the Hi-Hi alarm doesn't increase the probability of occurrence, the consequences or the possibility of a different type of accident since no credit is taken for this function in the Tech. Specs. or UFSAR. By restoring the ability of the operator to receive alarms for the incore sump, this TM improves the ability to respond to a small break LOCA.

The margin of safety of the Tech. Specs. (containment leakage) is based on early detection of leakage and is consistent with Reg. Guide 1.45, May 1973. Threshold values are as low as possible based on industry experience yet not too low to unnecessarily restrict operation. The restoration of this system which is not even taken credit for in the Safety Analysis only serves to improve the margin of safety with regard to RCS leakage.

The TM is limited to the Incore Sump Hi-Hi level alarm, and will not adversely affect the operation of any component used to mitigate the consequences of any accident. Operation of this alarm is not required for he mitigation of any analyzed accident, nor is it required to operate to maintain the plant in a safe condition.

The change does not impact any Tech. Spec., TRM or License Conditions. Compliance with the specifications will be maintained.

This TM is an electrical modification to the Control Room annunciator circuit and does not affect the environment in any way.

**01-SE-TM-03**

**Description**
Temporary Modification (TM) N1-1694
Roll leads at 1-EI-CB-23D TB 7 and 8 and at local junction box JB-2115 TB 1 and 2 for 1-SW-PI-110, 1-SW-P-4 Discharge Header Pressure.

**Summary**
A ground was discovered on the positive lead (black) of the PI circuit causing indication failure of 1-SW-PI-110, 1-SW-P-4 Discharge Header Pressure Transmitter. The Temporary Modification (TM) involves rolling leads at 1-EI-CB-23D TB 7 and 8 and at local junction box JB-2115 TB 1 and 2 for 1-SW-PI-110. Swapping the leads will allow the ground to be transferred to the negative (white) side of the circuit, which is normally grounded. This action will restore the circuit to a functional condition, and allow it to be functionally tested and returned to operable status. The transmitter should perform as expected with no spurious signals.

The TM will be installed and remain in place until the associated cable can be permanently repaired. Use of the temporary arrangement is considered acceptable in the short term to restore the channel to operable status. The long term corrective action will eliminate any degraded condition associated with the existing cable. These short term and long term corrective actions are compliant with Generic Letter 91-18 (Information on resolution of degraded and nonconforming conditions) guidance regarding the treatment of component operability and restoration of qualification. As previously mentioned, the short term action will allow the channel to be returned to a functional condition and returned to operable status.

UFSAR Section 9.2.1 describes the Service Water System. The TM will not change the purpose or function of the pressure indication loop. A functional test after the configuration change will ensure accuracy and operability of the indication. The reconfiguration will not cause adverse effects in the parameter indication. The TM is limited to one pressure instrument loop. There will be no affect on any other instruments. Channel separation will not be compromised.

The TM does not involve or create an Unreviewed Safety Question. The indication loop itself is used to monitor the status and performance of the Auxiliary Service Water Pump. The indication is not associated with the initiation of any accident/malfunction or any accident/malfunction precursor. Therefore, the TM will not increase the probability of an accident or malfunction. Since the TM will restore the indication loop to operable status, the instrument will be available to monitor Auxiliary Service Water Pump pressure. As such, the TM will not increase the consequences of any accident or malfunction. No new equipment, instrument components, or new failure modes are introduced, so no new accidents or malfunctions are created. The function of the instrument will remain the same, so no new Technical Specification surveillance requirements are required, nor are any License Condition changes necessitated. Therefore, the margin of safety as described in the Technical Specification Bases for the Service Water System and other related systems is unchanged.

**01-SE-TM-04**

**Description**
Temporary Modification N2-1140
Temporarily remove coil wires # 73 from both bridge 4A relays, for Polar Crane 2-MH-CRN-1.

**Summary**
The polar crane is designed and constructed to comply with ANSI B30.2.0-1967 and the Electric Overhead Crane Institute, Inc., "Specification for Electric Overhead Traveling Cranes". The rotational speed of the bridge is controlled by 5 relays that consist of resistor banks. These relays actuate to increase or decrease the rotational speed of the four bridge motors in a controlled manner. One of the two bridge 4A relays is currently sticking, which is bypassing the first three resistor banks. This is causing the bridge to jerk to a high speed from rest when the motors are energized. It is desired to lift coil wires #73 (Vendor Drawing, Harnischfeger P & H, # 101A5263) in the bridge control panel located on the Polar Crane bridge, to bypass the 4A resistor bank to the bridge motors. This will limit the top speed of the bridge motors, but will provide for speed control.

A review of the design specification for the Polar Crane in accordance with vendor technical manual, 59-H800-00001, indicates there are no speed requirements for the bridge. A review of the Electric Overhead Crane Institute, Inc., "Specification for Electric Overhead Traveling Cranes" indicates that the trolley and bridge brakes have been designed to stop the trolley or bridge within a distance in feet equal to 10 percent of full load speed in feet per minute when travelling at full speed with full load. Limiting the speed of the bridge motors is within the design of the brakes and is more conservative. Operation of the crane with a load is not affected in any way by this activity. There is no requirement in the ANSI Safety Code for limiting the speed of the bridge. Limiting the speed of the bridge motors does not affect the function or operation of the crane in any way.

The TM does not involve or create an Unreviewed Safety Question. The polar crane bridge speed is not associated with the initiation of any accident/malfunction or any accident/malfunction precursor. Therefore, the TM will not increase the probability of an accident or malfunction. Since the TM will restore speed control to the bridge, this will provide for safer operation of the polar crane. As such, the TM will not increase the consequences of any accident or malfunction. No new equipment, instrument components, or new failure modes are introduced, so no new accidents or malfunctions are created. The function of the polar crane will remain the same. There are no Technical Specification requirements associated with the polar crane, and there are no License Condition changes required. As such, the margin of safety as described in the Technical Specification Bases remains unchanged.

**01-SE-TM-05**

**Description**

Temporary Modification: No. 1695 (Unit 1) and 1139 (Unit 2)
WO # 00447260-01, 00447260-02, 00447261-01and 00447261-02
ET N-00-134
1-PT-71.1Q and 2-PT-71.1Q - With an OTO change that will permit performing response time testing with the recirculation valve full open. It will also add steps to record the maximum flow achieved during testing.
The first orifice (1-FW-RO-102A and 2-FW-RO-202A) in the full flow recirculation line for each turbine driven AFW pump will be removed and replaced by orifices sized to limit the pump discharge to about 345 gpm.

**Summary**

Each of the TDAFW pump full flow recirculation lines are fitted with two flow restricting orifices (1-FW-RO-102A/103A and 2-FW-RO-202A/203A) designed to limit the recirculation flow to 809 gpm. Currently, the TDAFW pumps are tested at flows in the range 340 to 345 gpm. To achieve the targeted test flow range, the recirculation valve is opened until the valve position indicator is aligned with the 340-345 position marked on the valve yoke. However, the flow characteristic of the recirculation valve is such that relatively small changes (between 3/32 and 1/8 inch) in the indicated valve position yield a significant change (about 270 gpm) in flow. Thus, it is almost impossible to achieve repeatable initial flow rates by aligning the position indicator with the 340-345 position marked on the valve yoke.

An evaluation conducted per ET N 00-134, Rev. 0, concluded that the first orifice in each recirculation line can be resized and replaced to limit the recirculation flow to about 345 gpm with the recirculation valve full open. Replacing this orifice will eliminate the need for throttling the recirculation during the initial portion of surveillance tests, and will eliminate the uncertainty associated with setting the recirculation valve to the precise point to achieve flow in the desired range.

This Safety Evaluation assesses the impact of replacing the first orifice in each recirculation line on a Loss of Normal Feedwater and a Major Secondary System Pipe Rupture.

The intent of this modification is to enable pump testing to begin initially with the recirculation valve full open. Operating the pump in this manner does not constitute a special test since the recirculation system was designed for operation with the recirculation valve full open or throttled.

In summary, the modification will be installed by Work Orders 00447261-01 (Unit 1) and 00447260-01 (Unit 2). Replacement of the orifice at 1-FW-RO-102A may be performed with the recirculation valve tagged closed. Replacement of the orifice at 2-FW-RO-202A requires that the pump be tagged before the orifice is replaced. After each orifice is replaced, the pump will then be readied for testing per 1/2-PT-71.1Q that will contain an OTO change. The OTO change will permit performing response time testing with the recirculation valve full open. The OTO change will also add steps to record the maximum flow achieved during testing.

The modification and testing described above will not affect the likelihood of a loss of normal feedwater or a major secondary system line rupture as the work to be performed will not affect the Main Steam or the Main Feedwater Systems. Thus, the consequences of these accidents are not changed. There are no reactivity effects associated with this modification. This modification will not affect either the main or control power associated with the AFW pumps and valves. The possibility of the creation of a different type of accident than previously analyzed does not exist. In addition, the proposed modification will have no effect on the auto start circuitry of the AFW pumps; as such it cannot cause a failure of the TDAFW pump to start on receipt of an auto start signal.

The modification affects only the discharge through the recirculation line, which is isolated, when the pump is in standby. The replacement orifice has been sized to limit the discharge to about 345 gpm, whereas the original orifice was sized to limit flow to 809 gpm. Since the bore of the new orifice is less than the

currently installed orifice, it is unlikely that the pump will runout during testing. A failure of the orifice during testing, while very unlikely, could result in excessive flow that can lead to pump damage. Therefore, the OTO par will instruct the operator stationed in the MCR to stop the pump should flow exceed 600 gallons. Thus adequate measures to mitigate significant leaks and orifice failures will be available during this activity. Moreover, the margin of safety for AFW pump operation is not affected. For these reasons, an unreviewed safety question does not exist, and this activity should be allowed.

**01-SE-TM-06**

**Description**
Temporary Modification - N2-1141
2-AR-T-C2
VPAP-1403
Lift leads from 2-GM-LS-210-2 (Unit 2 Main Generator Defoaming Tank Level Switch – Turbine End) to clear a locked-in defoaming tank level alarm (2T-C2, DEFOAMING TANK LEVEL – HIGH) on the Turbine Supervisory Panel in the MCR (2-EI-CB-10) with no high oil level condition present.

**Summary**
The Unit 2 Defoaming Tank High Level Alarm annunciator (2T-C2, DEFOAMING TANK LEVEL – HIGH) is locked-in on the Turbine Supervisory Panel in the MCR. The annunciator is fed by both 2-GM-LS-210-1 (Unit 2 Main Generator Defoaming Tank Level Switch - Exciter End) and 2-GM-LS-210-2 (Unit 2 Main Generator Defoaming Tank Level Switch - Turbine End). Both level switches were checked during the March, 2001 Unit 2 refueling outage and 2-GM-LS-210-1 (Exciter end) was replaced. The current alarm condition has been verified by Electrical Maintenance to be from an actuation of 2-GM-LS-210-2 (Turbine end). A visual examination of both the Turbine End and Exciter End Defoaming Tank level indications shows that no high level condition exists in either tank. Both oil levels are well below the High Level alarm setpoint. A significant layer of foam was found to exist above the oil in the tanks. Based on past experience, it is suspected that a high oil level actually existed for a brief time (possibly during the startup of the turbine-generator) and that now the oil level is normal. The layer of foam above the oil, however, is believed to be holding the float type level switch up in the Turbine end tank and preventing the alarm condition from clearing. A Work Request has been submitted to investigate and repair the alarm switch. However, due to the difficulty in accessing the level switch and the potential for disrupting the seal oil system, it is prudent to not try to repair the level switch with the generator on line as long as other options exist.

The annunciator does not have reflash capability. Therefore, an actuation of 2-GM-LS-210-1 (Exciter end) will not cause an alarm in the Control Room. It is desired to clear the locked in alarm from 2-GM-LS-210-2 to allow alarm capability for the remaining switch. This will provide a warning of any subsequent defoaming tank high level conditions from the Exciter end. As the two defoaming tanks are connected through a common line, the level switch in the Exciter end tank can be used to help indicate a high oil level in the Turbine end tank. Without performing this temporary modification (TM), the existing alarm annunciator is useless as a warning tool for changing conditions. The TM will lift leads from 2-GM-LS-210-2 (Unit 2 Main Generator Defoaming Tank Level Switch – Turbine End) in Junction Box 003-2 to clear the locked-in defoaming tank level alarm. The temporary modification will remain in place until the completion of maintenance to repair/replace the switch.

The Generator Hydrogen Seal Oil system is only vaguely described in the UFSAR (Section 10.2). The description of the system does not include the defoaming tank or its alarms. The only reference to any alarms is a brief statement that the Hydrogen Control system has an alarm system to provide warning of improper system operation. Performance of the TM will restore the usefulness of the remaining defoaming tank level switch, and thus will restore alarm capability to provide warning of any subsequent operational problem involving the defoaming tank. Therefore, the TM will improve the current condition of the alarm system and enhance the ability to detect a malfunction in the Generator Seal Oil System.

There are no T.S. LCOs associated with the Generator Seal Oil System.

The Generator Seal Oil System provides an oil seal at the Turbine/Generator rotor interface with the Main Generator housing to prevent the escape of Hydrogen from the Main Generator. Hydrogen is used as a cooling medium for the Generator. A malfunction of the system could result in the loss of one or more of the Hydrogen oil seals which could cause a loss of Generator cooling and potentially cause flammable or explosive conditions around the seals. Such a failure of the system would be detected by various alarms and result in a shutdown of the Main Generator and Turbine. The Main Generator is designed to contain any explosion without damage to life or property external to the machine. Fire Protection at the machine

provides suppression capability to prevent the spread of any fire. Catastrophic failure of the Main Generator will not adversely affect Safety Related systems or components needed to safely shutdown the unit. The TM will enhance the ability of the alarm system to detect a Seal Oil system malfunction so that actions may be taken to correct the condition prior to failure of the system.

As the level switch only provides an alarm function, this TM will not introduce any new accident or event precursors. There are no control or protective functions that are associated with the level switch, therefore, this TM will not increase the probability of occurrence of an accident nor will it increase the consequences of any accident. No new accident or malfunction is introduced as no new equipment is added per this TM. The level switch is not part of any system required by the Technical Specifications and this TM does not reduce the margin of safety as described in the bases section. This TM does not adversely affect any releases to the environment and does not affect the ability of the station to achieve and maintain safe shutdown in the event of a fire.

For these reasons, an Unreviewed Safety Question is not created by the performance of the TM.

**01-SE-TM-07**

**Description**
Temporary Modification #N2-1142
The leads are swapped for the Unit 2 "C" Reactor Coolant Pump (RCP), 2-RC-P-1C, seal leakoff temperature element (2-CH-TE-2126) and pump radial bearing temperature element (2-CH-TE-2125), and it is desired to swap the wires at Junction Box JB-781-2 (RCP Thermocouple Transfer Junction Box) for the temperatures to read correctly on the P-250.

**Summary**
Temperature elements 2-CH-TE-2125 and 2-CH-TE-2126 provide indication of the Unit 2 "C" RCP radial bearing temperature and shaft seal water outlet temperature on the P-250, respectively. During the last Refueling Outage the wiring was verified to be correct in accordance with drawing 12050-FE-7BX per Work Order # 428041-01. During the plant startup, when monitoring the "C" RCP parameters, the shaft seal water return and the pump radial bearing temperatures appeared suspect. When compared to the "A" and "B" RCPs, the seal water temperature appeared lower than expected, and the radial bearing temperature appeared higher than expected. It is believed the leads for the temperature elements may have been swapped during the wiring verification.

An e-mail from B. Harper (NAPS System Eng.) to Larry Lane (NAPS Operations) dated 4/19/01, indicated that the current temperature readings were compared to those prior to the outage to support the notion that the leads are swapped. 2-CH-TE-2125 (pump radial bearing) indicated approximately 138°F before the outage and approximately 167°F after the outage, and 2-CH-TE-2126 (seal water outlet) indicated approximately 173°F before the outage and approximately 123°F after the outage. It specifically states:

> "Temperature data across the Unit 2 RCP #1 seals from before and after the refueling outage has been evaluated. Radial bearing temperatures for the "A" and "B" pumps are 15 and 23 degrees lower respectively following the refueling outage. This is expected with lower seal injection temperatures (due to lower CC temperature). However, the "C" RCP radial bearing temperature is currently 29 degrees higher than pre-outage data. When reviewing the differential temperatures across the seals, it is noted that the "C" RCP seal water outlet temperature is lower than the radial bearing temperature. As there is no cooling mechanism between those two points, the "C" RCP radial bearing temperature indication (2-CH-TE-2125) is considered suspect and should be used for trending purposes only. Note that the wiring for this instrument was verified during the refueling outage under WO 428041-01. Post outage RCP seal differential temperatures are: "A" 43 degrees, "B" 30 degrees and "C" negative 44 degrees. "

UFSAR Section 5.5.1 describes the Reactor Coolant Pumps in detail. The journal-type radial pump bearing is water-lubricated from seal injection flow. Temperature elements 2-CH-TE-2125 and 2126 are used to evaluate the pump during normal operation and during adverse conditions such as a low or loss of seal injection/leakoff flow. In order to properly evaluate pump performance, it is desired to swap the leads at Junction Box JB-781-2 to ensure the "C" RCP parameters can be properly trended and pump and seal performance can be properly evaluated. This Temporary Modification (TM) will swap the leads for both temperature elements at the RCP Thermocouple Transfer Junction Box, JB-781-2. Referring to Test Loop Diagram 12050-CH-032 for 2-CH-TE-2125, the leads from terminals TA-4, TA-5, TA-6, and TA-10 will be lifted at JB-781-2. Referring to Test Loop Diagram 12050-CH-033 for 2-CH-TE-2126, the leads from terminals TA-14, TA-15, TA-16, and TA-20 will be lifted at JB-781-2. The leads for 2-CH-TE-2125 will then be relanded at terminals TA-14, TA-15, TA-16, and TA-20, while the leads for 2-CH-TE-2126 will be relanded at terminals TA-4, TA-5, TA-6, and TA-10.

The TM does not involve or create an Unreviewed Safety Question. The temperature indications are used to monitor the status and performance of the "C" Reactor Coolant Pump. The indication is not associated with the initiation of any accident/malfunction or any accident/malfunction precursor. Therefore the TM will not increase the probability of an accident or malfunction. Since the TM will correctly restore the temperature indication for both 2-CH-TE-2125 and 2-CH-TE-2126, the instruments will be available to properly evaluate

Reactor Coolant Pump performance. As such, the TM will not increase the consequences of any accident or malfunction. No new equipment, instrument components, or new failure modes are introduced, so no new accidents or malfunctions are created. The function of the temperature elements will remain the same, that is, to provide indication of seal water temperature at the pump radial bearing and number 1 seal leakoff temperature. No new Technical Specification surveillance requirements are required, nor are any License Condition changes necessitated. Therefore, the margin of safety as described in the Technical Specification Bases for the Reactor Coolant system, Charging system, and other related systems is unchanged.

01-SE-TM-08

**Description**

Temporary Modification TM-N1-1697
Main Turbine speed pickup #4 has failed and can not be repaired until the next outage. This speed pickup provides input to the Turbine Supervisory panel's speed indication, Bearing Lift Pump (1-GM-P-10), and the Turning Gear Motor Circuit. A spare speed sensor input will be used as a one-for-one replacement until repairs may be performed at the next refueling outage.

**Summary**

Main Turbine speed pickup #4 has failed and can not be repaired until the next outage. This speed pickup provides input to Turbine Supervisory panel's speed indication and a start permissive to Bearing Lift Pump (1-GM-P-10) and the Turning Gear Motor Circuit. A spare speed sensor input will be used as a one-for-one replacement until repairs may be performed at the next refueling outage.

The failed speed sensor provides a start permissive to Bearing Lift Pump 1-GM-P-10 when turbine speed decreases to less than 600 RPM. With the speed indication failed, the lift pump must be left in OFF instead of AUTO. Use of a spare speed input will allow the lift pump control to be returned to AUTO and restore turbine speed indication to the Turbine Supervisory Panel.

This Temporary Modification will not increase the probability of occurrence for any accidents in any way. The spare speed sensor is identical to the failed sensor. Failure modes of the turbine and its control systems are not affected in any way. Failure of the speed sensor will result in a start permissive to the Bearing Lift Pump, 1-GM-P-10, which does not adversely affect the turbine in any way.

This Temporary Modification will not increase the consequences of any accidents in any way. The consequences of failure of the Temporary Modification are identical to those associated with the normal speed indication. The installed spare is identical in location, calibration, and operation with the sensor that has failed.

This Temporary Modification will not create the possibility for an accident of a different type than was previously evaluated in the Safety Analysis Report since the installed spare is identical in location, calibration, and operation with the failed sensor.

**01-SE-TM-09**

**Description**
Temporary Modification #1143
Installation of a video camera and associated equipment to observe oil level in the lower oil reservoir for the 2-RC-P-1A motor. The camera will be mounted on a free-standing stanchion several feet away from the oil reservoir sight glass. The output of the device will be routed to the Main Control Room for remote monitoring of the level.

**Summary**
The activity evaluated is the installation of a video camera and associated equipment to observe oil level in the lower oil reservoir for the 1-RC-P-1A motor. The camera will be mounted on a free-standing stanchion several feet away from the oil reservoir sight glass. Two drop lights will be fastened to a handrail in the vicinity of the sight glass to provide sufficient lighting for the camera. The output of the device will be routed to the Main Control Room for remote monitoring of the level. The camera and its associated equipment will be installed as a Temporary Modification (TM).

The purpose of the camera installation is to provide a means to remotely monitor the oil level in the reservoir to ensure adequate level. The Main Control Room Annunciator for the 2-RC-P-1A oil reservoir level has been coming in and out of alarm due to an indicated low level condition. An attempt to drain oil from the RCP oil collection tank revealed that there was relatively no oil in the tank. Oil was added to the reservoir to clear the alarm. The alarm has been verified to be generated from the low level switch in the lower reservoir. It is desired to remotely monitor the oil reservoir sight glass. This will allow the level to be conveniently checked as often as desired. Since the sight glass will be remotely viewed, the TM will provide higher quality oil level information to the Operator than the existing level alarm. In addition, it will provide a means to trend the indicated level without repeated Containment entries (long term dose savings). Early detection of an adverse level trend will reduce the chances of bearing failure, and thus, reduce the chances of an RCP motor trip and Reactor Trip. [It should be noted that a failure of a motor bearing will not cause a Locked RCP Rotor event (UFSAR Section 15.4.4) or a Complete Loss of Forced Reactor Coolant Flow event (UFSAR Section 15.3.4) as described in the UFSAR. The UFSAR evaluation of an RCP motor bearing failure assumes that no sudden bearing seizure results; this is due to the consideration of the melting characteristics of the babbitt material. It is assumed that the motor will continue to run following the failure until high current demand requires the motor to be shutdown. An individual motor bearing failure will ultimately result in the loss of one RCP; the remaining two RCPs continue to run providing forced coolant flow].

The camera and associated equipment will be restrained such that during a seismic event, it will not damage any safety related equipment significantly (the camera is not required to function during or following a seismic event). The two portable drop lights will be fastened on a handrail in the vicinity of the oil reservoir sight glass. Each light will contain a 100 watt halogen bulb. Two lights will be installed for reliability in case one of the bulbs burns out. The bulbs will not be in contact with any equipment, and the heat associated with these bulbs will be dissipated by the surroundings. The lights will be powered from a local convenience receptacle. The camera flexible cable will not be a concern, since it is not expected to be accelerated during a seismic event. The camera will be powered by a 120 volt local receptacle in Containment which is not powered from an Emergency Bus; therefore, failure of the camera will not affect an Emergency Bus. The breaker supplying the receptacle will provide adequate protection to prevent any "shorts" from feeding back and damaging the electrical penetration; therefore Containment Integrity will be maintained. The monitor located in the Main Control Room will be seismically restrained and will be located away from the main control panels (next to the Unit 2 Mind printer). The monitor will be powered from a local 120 volt convenience outlet which is supplied by the 2J Emergency Bus. The addition of electrical load from the camera and monitor via the convenience receptacles is minimal, and the additional loading from the convenience outlets in the Main Control Room has been previously evaluated and accounted for in the design of the emergency electrical distribution system. The camera and associated equipment are constructed mostly of metals such as aluminum and stainless steel. In the event of a LOCA or MSLB, should any pieces of the camera or associated equipment fall to the Containment Sump, the screening around the sump would be adequate to prevent intrusion into the RS and SI pump suction. The

design of the sump and debris screens is such that any related debris that can pass through the series of coarse and fine mesh screening will not adversely affect system components. The area of the screening covered by the debris would be negligible. The sump screen area is approximately 168 square feet; it is judged that any camera and associated equipment related debris would not cover more than 2 square feet. Engineering has reviewed the estimated amount of aluminum added to the Containment due to the installation of the camera and associated equipment and has determined that it is within allowable specification; therefore, the added post-accident hydrogen generation potential introduced by the installation of the TM is not a concern.

Installation and use of the camera and associated equipment will not change the performance characteristics or the RCP or its support systems. The camera performs no control or protective functions. The camera is essentially a passive device used for monitoring purposes only. No safety related systems or components will be adversely affected by the installation of the camera during normal or accident conditions.

For these reasons, installation of the TM will not create an Unreviewed Safety Question.

**01-SE-TM-10**

**Description**
Temporary Modification (TM) N1-1696
WO# 434982 01
Lift the leads at 1-GM-TS-102B to disable the input to annunciator K-B7 (Generator Leads Cooling Trouble).

**Summary**
Temperature switch 1-GM-TS-102B, "B" phase bus duct air temperature, is alarming prior to the setpoint of 175 degrees Fahrenheit and periodically causes annunciator K-B7 to lock in on hot days. Since the temperature switch can not be repaired or calibrated on line, and the annunciator has no reflash capability, it is desired to lift the leads from the switch to disable the input to the annunciator until the Winter months. Since there is no reflash associated with this annunciator, other inputs will have no effect on the alarm when it is locked in, and therefore it is beneficial to remove the degraded input to this annunciator.

Although there will be no input to annunciator K-B7 from the "B" phase bus duct temperature, the following inputs will still be available to cause a Generator Leads Cooling Trouble alarm:

1-GM-TS-102A & C, high "A" and "C" phase bus duct air temperature;
1-GM-TS-103A through -103F, high "A", "B", and "C" main transformer low side bus temperature;
1-GM-TS-104, high generator bus duct cooling return air temperature;
1-GM-FS-100, low generator bus duct supply air flow
1-GM-FS-101, loss of water flow to generator leads cooler
1-GM-MS-100, high relative humidity of the cooling air supply

Temperature switch 1-GM-TS-102B provides no other function than providing an input to K-B7. There are numerous inputs to the annunciator that would alert the operator to a problem with the generator leads bus duct air cooling system or the Bearing Cooling Water system which is used to cool the air. In addition to the above mentioned inputs, there are temperature indicators installed in bus ducting, and therefore, temperatures of each phase can be obtained locally.

This Temporary Modification does not constitute an Unreviewed Safety Question for the following reasons:

1. Removing the input from 1-GM-TS-102B to annunciator K-B7 does not affect any automatic safety functions.

2. The temperature switch is not Safety Related, has no Tech Spec requirements and is not described in the UFSAR. The probability or consequences of an accident are not affected.

3. The probability or consequences of an accident or malfunction occurring previously evaluated in the SAR is not increased, nor is the possibility of creating a new accident or malfunction increased as a result of this temporary modification.

Therefore, this Temporary Modification does not involve an Unreviewed Safety Question and no changes are required to the Operating License.

**01-SE-TM-11**

**Description**

Temporary Modification 01-1698

Approval to install a temporary chemical addition system to the BC system. This temporary chemical addition system will be used to add Calgon Biocide, H-900 in the tablet form, to the BC system. H-900 is approved for use and was normally added to the Bearing Cooling (BC) system per VPAP-2201 and 2202 via the Brominator (1-BC-TK-4) prior to replacement with the activated bromine system. The Brominator had to be removed from service due to an oil-intrusion incident on the BC system (reference PI N-99-2478). The activated bromine system is currently not available due to the failure of pump 1-BC-P-7A (Ref. PI N-2001-1708). Hence, it is being proposed to apply H-900 tablets at the top of the Bearing Cooling (BC) tower in the hot water distribution basin. The tablets will be placed in one or more plastic containers to facilitate solubility and to prohibit direct contact with the wood structure of the tower.

**Summary**

H-900, which was applied via the Brominator (1-BC-TK-4), is an approved biocide for the Bearing Cooling (BC) system per VPAP-2201 and 2202. The Brominator was removed from service due to an oil-intrusion incident on the BC system (reference PI N-99-2478). The brominator was replaced with the activated bromine system that is currently unavailable due to failure of pump 1-BC-P-7A (Ref. PI N-2001-1708). Hence, approval for the use of a temporary chemical addition system, which will be used to add Calgon Biocide (H-900) in the tablet form to the BC system, is being sought. It is being proposed to apply the H-900 tablets at the top of the Bearing Cooling (BC) tower in the hot water distribution basin. The tablets will be placed in one or more plastic containers to facilitate solubility and to prohibit direct contact with the wood structure of the tower. The oxidizing agents in H-900 promote wood decay when used in high concentrations over extended periods of time. This interim application will not produce any long-term effects.

To address the plant safety significance of the TM, the following accidents per the SAR were considered:

UFSAR Chapter 15.2.8 – Loss of Normal Feedwater: The loss of Bearing Cooling could result in a Main Feedwater pump trip or failure because the BC system provides pump seal-oil cooling.

> It is unlikely that this interim use of H-900 in the tablet form in the Bearing Cooling tower would result in the loss of Bearing Cooling. This TM does not increase the probability of occurrence or increase the consequences of the Loss of Normal Feedwater accident. The plastic container used to deliver the H-900 is larger than the flow holes through which the BC water cascades down in the wood structure. Additionally, this modification does not impact any safety systems used to mitigate this accident, mainly Auxiliary Feedwater and its associated components.

UFSAR Chapter 6.4 Habitability Systems, for the Control Room to ensure that continuous occupancy of the area is possible for the events described in chapter 3 as well as all the postulated accidents discussed in chapter 15.

> The use of H-900 in tablet form will not impact the Control Room habitability analysis. The H-900 biocide will be used on site in small quantities (40-50 lb.). Bulk storage (>100 lb.) will remain in warehouse #7, which is greater than the required .3 miles. H-900 in crystal form, is an approved chemical for use in the BC system. This chemical will be handled and administered by trained chemistry technicians in accordance with Chemistry Special Order 01-005 and procedure CH-99.301.

Thus, no unreviewed safety question exists.

Note: This safety evaluation can be used as the basis for approval of a procedurally controlled temporary modification if a future need should arise.

**01-SE-TM-12**

**Description**
Temporary Modification #1144
Install an electrical jumper between terminals 2-15 and 2-16 of junction box RCPV 16B to disable the Unit 2 Control Room annunciator 2C-F1, "RCP 1A OIL RES HI-LO LEVEL."

**Summary**
This temporary modification installs an electrical jumper between terminals 2-15 and 2-16 of junction box RCPV 16B to disable the Unit 2 Control Room annunciator 2C-F1, "RCP 1A OIL RES HI-LO LEVEL." This activity is being done because the level in the lower motor bearing oil reservoir on the "A" RCP is oscillating at the lower alarm limit. The increased frequency of the low level alarm is causing a distraction to the Control Room Board Operators. Also, this jumper will enhance the Board Operator's ability to respond to level alarms from the upper oil reservoirs. The most likely cause of the condition has been tentatively identified as a restriction in the air flow through a vent pipe between the reservoir and its remote level indication.

The UFSAR specifically addresses this oil level alarm. It states that this alarm shall be used in conjunction with bearing temperature indication to monitor operation of the pump. Pump shutdown is required in the event of high bearing temperatures. Performance characteristics will not be altered by this Temporary Modification. Monitoring of the bearing temperature indication and P-250 alarms, will provide adequate assurance that the pump is not degrading. The alarm setpoint for P-250 point T0415A will be lowered from 185° F to 140° F. The setpoint can be adjusted as necessary for changing ambient conditions.

Jumpering out the annunciator can not affect the potential for any evaluated accidents. The TM only defeats the RCP motor lower oil reservoir level alarm. This will decrease the frequency of occurrence of the alarm which is currently causing a distraction to the Control Board Operators. The jumper will in no way affect the operating characteristics of the RCP. Also, if there is a single motor bearing failure, it will not cause a 'locked RCP rotor' or a 'complete loss of forced reactor coolant flow' event. UFSAR Section 5.5.1.3.4 discusses failure of the bearings, based on this discussion bearing failure will not affect the consequences of any UFSAR analyzed accidents. Disabling the alarm will not affect the Board Operator's ability to monitor bearing temperatures, so there is no way to affect the ability to mitigate and recover from effects of a locked RCP rotor, a loss of all RCP's or any other chapter 15 accident.

Because the UFSAR section 5.5.1.3.4 has already analyzed the plant to essentially lose indications pertaining to monitoring RCP bearings and the failure mode associated with the bearings, defeating the annunciator does not create any accidents or malfunctions of a different type. Disabling the annunciator does not increase the probability that the bearing will fail. Monitoring of the RCP will continue via bearing temperatures. The TM will not provide or remove any control or protective functions for the RCP.

The UFSAR has a discussion of the failure mode of the bearings—this is not altered by disabling the annunciator. The consequences of an RCP failure is an automatic or manual reactor trip, dependent on at-power plant conditions—this failure mode is also not change as a result of disabling the RCP motor lower oil reservoir level annunciator. No adverse operational effects are introduced by using this jumper.

Margin of safety is not reduced by defeating the RCP motor lower oil reservoir level annunciator. The annunciator, nor the bearings are TS equipment, and they do not affect accident mitigation equipment. This jumper does not require any changes to TS's or the Operating License.

Based on the above discussion, no Unreviewed Safety Question exists.

**01-SE-TM-13**

**Description**
Temporary Modification – N2-1145
This Temporary Modification will defeat the Mechanical Chiller (2-CD-MR-1) compressor high thrust bearing oil temperature trip due to the Chiller tripping with normal bearing oil temperature.

**Summary**
The Mechanical Chiller has been unnecessarily tripping due to a faulty bearing module in the Chiller Control Panel (2-EP-CB-59). The purpose of the bearing module is to sense the Chiller compressor thrust bearing oil temperature via RTD, 2-CD-TE-702, and to trip the compressor via temperature switch, 2-CD-TS-702, when oil temperature reaches its setpoint of 201°F. The actual module consists of the temperature switch.

The jumper will consist of landing a lead across the temperature switch, 2-CD-TS-702, terminal points "CC" to "CC". By doing this, the Chiller compressor thrust bearing high oil temperature automatic trip is defeated. All other automatic Chiller trips will continue to provide protection to the Chiller components and will not be affected by the installation of this jumper. An Operations or HVAC group individual will be locally stationed at the Mechanical Chiller while this jumper is in place. The function of this individual will be to continuously monitor the compressor thrust bearing temperature via the local temperature indicator and to manually trip the Chiller in the event oil temperature increases to above 190°F.

The temperature trip requirement of 190°F was chosen to provide an additional factor of safety with the Chiller compressor thrust bearing high oil temperature automatic trip defeated. It will give the individual monitoring the Chiller parameters adequate time to take action to manually trip the Chiller and ensure the automatic temperature limit of 201°F is not exceeded. This does not warrant a setpoint change since defeating the auto trip is temporary and manually tripping the Chiller at a temperature below 201°F is added protection against damage to the compressor thrust bearing.

In the event the individual monitoring the compressor thrust bearing oil temperature does not manually trip the Chiller, the thrust bearing may fail, and the Chiller would most likely trip on compressor motor overload or high motor temperature. The consequences of the bearing failure and subsequent Chiller trip would be an increase in chilled water temperature, containment partial air pressure decreasing and containment temperature increasing. The Containment Air Recirculating Fans (CARF's) would have to be swapped to service water. Tech. Spec. 3.6.1.4 requires the containment partial internal air pressure to be maintained greater than or equal to 9.0 psia and Tech. Spec. 3.6.1.5 requires that containment average temperature be maintained greater than of equal to 86 degrees F and less than or equal to 120 degrees F.

The primary loads on the Mechanical Chiller are the CARF cooling coils, the gas stripper vent chillers, sampling coolers and the waste gas recombiner after cooler, as necessary. Loss of chilled water to the CARF's is addressed by abnormal procedure AP-35.

This does not pose an unreviewed safety question because of the following:

1) The Mechanical Chiller is not a safety related component. The UFSAR clearly states that the chiller "does not supply water to equipment that is required to operate to maintain the plant in a safe condition".

2) No Technical Specification deals either directly or indirectly with the Chilled Water System.

3) The individual stationed locally at the Chiller will provide some measure of protection and input to the compressor thrust bearing high oil temperature automatic trip feature which protects the chiller.

The likelihood of a chiller fault is not considered to be very great and all other chiller trips and protective functions remain in affect. The use of the chiller to provide cooling to the CARF's removes the requirement for the SW system to do so and improves the reliability and readiness of that system to provide essential core cooling and meet the requirements of an ultimate heat sink.

## SAFETY EVALUATION LOG
## PROCEDURES
## 2001

| S.E. # | Unit | Document | System | Description | SNSOC Date |
|---|---|---|---|---|---|
| 01-SE-PROC-01 | 1 | NA-M-DSE-800 (OTO1) | | Makes a OTO change to a switchyard procedure to adjust the position of the inlet isolation valve on the #1 cooling bank of the U1 "A" main transformer, 1-EP-MT-1A, in an attempt to stop the internal rattling | 1-04-01 |
| 01-SE-PROC-02 | 1,2 | ICP-RP-1-RPI-1, Att. 2<br>ICP-RP-2-RPI-1, Att. 2 | | Procedure-controlled temporary mod to jumper in regulated temporary power to the RPI system in the event the normal power supply fails | 3-02-01 |
| 01-SE-PROC-03 | 2 | 2-OP-3.2 (Rev. 41) | | Provides for opening the "B" RCS loop bypass valve, 2-RC-MOV-2586, in Mode 3 while shutting down for refueling | 3-07-01 |
| 01-SE-PROC-05 | 2 | 2-OP-5.7 (Rev. 9) | | Installs a temporary hose between an SI accumulator vent & a drain off of the RHR relief valve discharge line | 3-12-01 |
| 01-SE-PROC-06 | 2 | 0-OP-16.11 (Rev. 0) | | New procedure provides guidance for transferring water between the BRT and the Unit 2 RWST as a means of recovering the borated water. | 3-12-01 |
| 01-SE-PROC-07 | 2 | 2-OP-6.2 (R.15-P1) | | Uses a procedurally controlled TM to allow recovery of loop stop valve leakage from the PDTT pump discharge to the RP system. | 3-23-01 |
| 01-SE-PROC-08 | 2 | 2-MOP-7.31 (Rev. 1) | | Provides an alternative method to fill the SI accumulators from the refueling purification system while the RP system is lined up in one of the following configurations: (1) recirc to the U2 RWST; (2) U2 cavity to cavity; (3) pump down of the U2 RCS to the U2 RWST. | 3-27-01 |
| 01-SE-PROC-09 | 2 | 2-MOP-5.98 (Rev. 0) | | Allows opening of the loop stop valves to support backfill of drained loops one at a time from the water in the reactor cavity | 3-30-01 |
| 01-SE-PROC-10 | 1,2 | VPAP-2201 (R. 7)<br>CH-97.100 (R. 6)<br>VPAP-0306, Att. 3 | | Implements a change of reactor coolant chemistry pH control from the current "coordinated" program to a modified program which allows the pH(t) to increase as the fuel cycle progresses from an initial pH(t) of 6.9 to a final pH(t) of 7.4. | 4-17-01 |
| 01-SE-PROC-11 | 1,2 | 0-OP-4.13 (R. 0) | | "Inspection of Fuel Assembly Thimble Sleeves" | 5-17-01 |
| 01-SE-PROC-12 | 1,2 | 1-MOP-31.35A<br>1-MOP-31.35B<br>2-MOP-31.35A<br>2-MOP-31.35B | | New procedures to allow removal from service & return to service of selected drain coolers & FW heaters. Also permit maintenance on these HX during plant operation. | 5-24-01 |
| 01-SE-PROC-13 | 1,2 | 0-OP-52.1 (R. 3) | | Installation & removal of an electrical jumper that will defeat a domestic water (DM) booster pump's alternating circuit input in order to facilitate maintenance on a DW booster pump. | 6-12-01 |
| 01-SE-PROC-14 | 1,2 | 0-OP-4.11 (R. 0)<br>ET NAF 2001-0071 | | Nozzleless Fuel Assembly Handling Tool – this tool may be used to move F/As that have exhibited the potential for top nozzle separation. | 8-21-01 |

**SAFETY EVALUATION LOG**
**PROCEDURES**
**2001**

| S.E. # | Unit | Document | System | Description | SNSOC Date |
|---|---|---|---|---|---|
| 01-SE-PROC-15 | 1,2 | 0-OP-4.13 (R. 1) | | Provides instructions for visual inspection of irradiated fuel assemblies (F/A), which may possibly have degraded thimble sleeves. Fuel handling performed under this procedure consists of lifting the F/A a maximum of 4 ft, while the assembly remains inside the spent fuel pool rack cell in order to perform the visual inspections. Lifting will be performed with the station's spent fuel handling tool (not the nozzleless handling tool). | 12-04-01 |
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**01-SE-PROC-01**

**Description**
North Anna Switchyard Substation Maintenance Procedure, NA-M-DSE-800, "Substation Electrical Equipment Minor Maintenance/Troubleshooting".
Adjust the position of the inlet isolation valve on the # 1 cooling bank of the Unit 1 'A' Main Transformer, 1-EP-MT-1A, in an attempt to stop the internal rattling.

**Summary**
The Unit 1 'A' Phase Main Transformer, 1-EP-MT-1A, uses a forced-air and forced-oil cooled system to remove the heat from the transformer windings. There are 16 sets of fans located on 4 sets, or banks, of oil air coolers. The # 1 cooling bank of the Unit 1 'A' Main Transformer is currently tagged out due to internal noise/rattling coming from the cooler inlet isolation valve. With this cooling bank unavailable, the cooling capacity for the Unit 1 'A' Main Transformer is decreased, and it is desired to have all cooling banks available, especially during warmer weather.

In accordance with North Anna Switchyard Substation Maintenance Procedure, NA-M-DSE-800, "Substation Electrical Equipment Minor Maintenance/Troubleshooting", the # 1 cooling bank cooler inlet isolation valve position will be adjusted in an attempt to stop the internal rattling. More specifically, the valve will be partially closed in an attempt to stop the internal noise, however, flow will not be allowed to drop below 850 gpm +/- 10%. If this is unsuccessful, the valve will be modified and placed in the "over-toggle" position. The modification will consist of cutting a portion of the existing operating lever and fastening on a new lever so that it could be moved past its open stop. If the modification fails to stop the valve noise, all further attempts will be terminated.

The Main Transformers have no safety functions and are not relied upon for the safe operation of the plant. The oil air cooler isolation valves are butterfly valves and function to isolate the cooling unit from the transformer. The valve that is rattling is the inlet to the # 1 cooling bank and is physically located at the top of the 'A' Main Transformer. Currently, cooling banks 2 and 4 are in service with bank 3 in manual and the bank 1 oil pump tagged out. Failure of the valve adjustment/modification to stop the internal rattling should have no impact on the transformer performance at this time of year since ambient temperatures are cooler. However, all banks may be required to operate on warmer days, and the unit may be required to be ramped down or offline if transformer winding and oil temperatures can not be maintained below approximately 90 degrees Celcius.

The valve adjustment and/or modification to the operating lever will be performed by Substation personnel familiar with the equipment. There is risk to personnel safety with any work on or near an energized transformer. A potential for static electrification in the transformer exists anytime oil flow through the transformer is changed. Factors contributing to this condition include high oil flow rates and low oil temperature. For this activity, if the internal rattling stops when the valve is throttled in the closed direction, the oil flow rate through the bank 1 cooling unit will be decreased. If the valve requires modification to the over-toggled position, the flow rates may be higher. However, the winding temperature, oil temperature, and oil flow rate in the Main Transformers are monitored on a regular basis, and action would be taken to prevent this condition from occurring. Substation personnel are aware of these risks and are qualified to perform the work.

The margin of safety for the station as described in the Technical Specifications Bases is not altered since the Main Transformers are not described in the Technical Specifications. Based on the above major issues considered, there is no unreviewed safety question. The ability of the unit to shutdown and remain shutdown in the event of a transformer failure or fire is not affected.

UNREVIEWED SAFETY QUESTION ASSESSMENT:

1) Accident probability has not changed because the planned troubleshooting will not adversely affect the main transformer. No faults could be developed that would feed back into the switchyard to cause a station

blackout event. Loss of transformer cooling would require a unit power reduction but would not produce a sudden loss of turbine load.

2) Accident consequences are not increased. No safety equipment is affected by the proposed troubleshooting. If a loss of offsite power were to occur, the EDGs would operate to supply emergency power. The ability to remove the excess steam load on a loss of turbine load accident is not affected. The Main Steam safety valves, Main Steam PORVs, and steam dumps would all function as designed.

3) No unique accident probabilities/possibilities are created. The proposed troubleshooting will be performed by Substation personnel who are familiar with the power transformers. The work will be performed in accordance with a preplanned procedure. The only affect of the troubleshooting will be to the Unit 1 'A' Main Transformer cooling unit. All accident analysis remains bounded.

**01-SE- PROC-02**

**Description**

ICP-RP-1-RPI-1 Attachment 2
ICP-RP-2-RPI-1 Attachment 2
Procedurally controlled temporary modification (PCTM) to jumper in regulated temporary power to the RPI system in the event the normal power supply fails.
A temporary power supply to the RPI system will be used to provide power in the event the normal power supply (H-Bus Sola Transformer 01-EE-VREG-2, 02-EE-VREG-2-2) fails or to repair/replace a malfunctioning unit. The temporary power will be provided from the installed J-Bus transformer (01-EE-TRAN-92 / 02-EE-TRAN-92-2) through a portable power conditioner. The power conditioner will receive an unregulated input from the J-Bus Transformer and provide regulated power to the RPI cabinets that meets the system input power requirements.

**Summary**

A temporary power supply to the RPI system will be used to provide power in the event the normal power supply (H-Bus Sola Transformer 1-EE-VREG-2/2-EE-VREG-2-2) fails. The temporary power will be provided from the J-Bus (transformer 01-EE-TRAN-92 / 02-EE-TRAN-92-2) through a portable power conditioner. The power conditioner will receive an unregulated input from terminals located in the back of the "B" RPI cabinet and provide regulated power to the RPI cabinets that meets the system input power and regulation requirements.

The RPI system will function as designed with the temporary power supply installed and will maintain its function in the event of a loss of offsite power. Installation will occur only in the event of the loss of the normal power supply due to failure or the need to repair/replace a malfunctioning unit. During the power swap-over individual rod position indication will be lost briefly but the step counters will be unaffected ensuring the operators of continued but limited rod group position surveillance capability. Since the RPI system is isolated and separate from the Rod Control system, the power swap-over will not affect the operator's ability to move control rods.

The temporary power supply will be installed in a fashion that meets the seismic requirements of VPAP-0312 and will utilize an emergency bus (J-Bus). The temporary power supply will be as reliable as the normal power supply and meet the input power and regulation requirements of the RPI system. Per Corporate I&C Engineering, EMI/RFI concerns will be precluded by including steps in ICP-RP-1-RPI-1 Attachment 2 and ICP-RP-2-RPI-1 Attachment 2 that ensure the portable power conditioner is positioned such that it will not affect the protection or control circuitry. The power supply swap-over will be made in a "break-before-make" fashion thus ensuring that the emergency busses are not cross-tied. Per Corporate Power Engineering, the Unit 1 & 2 J EDG loading calculations assume 100% loading of transformers 01-EE-TRAN-92 & 02-EE-TRAN-92-2; therefore, this PCTM will not create any additional loading on the J-Bus that has not already been considered.

This PCTM meets the input power and regulation requirements of the RPI system and will not affect the operation of the system once installed. The temporary power supply is isolated from the J-Bus by a transformer and breaker; therefore, will not adversely affect the emergency busses or any other plant systems. The RPI system is separate and isolated from the Rod Control system; therefore, this activity cannot affect the movement of control rods or the Rod Control system. Installation of this PCTM will not increase the probability of occurrence or consequences of a loss of offsite power or a control rod accident, nor will it create the possibility of an accident not previously evaluated in the SAR. Installation of this PCTM will not increase the probability of occurrence or consequences of malfunctions of equipment important to safety, nor will it create the possibility of equipment malfunctions not previously evaluated in the SAR. The deliberate loss of the RPI system for a brief period of time to swap to a temporary power supply is preferable to a permanent loss or unreliable operation of the system and is in keeping with the desire to maintain the margin of safety as described in the basis section of tech specs. T.S. 3.0.3 will be entered during the period of time that the individual rod position indications are lost.

This PCTM should be allowed since it does not present any unreviewed safety questions and will maintain adequate safety margin while providing a reliable temporary power supply to the RPI system.

**01-SE- PROC-03**

**Description**
2-OP-3.2 – Unit Shutdown From Mode 3 to Mode 4, Revision 41
Open the "B" RCS Loop Bypass valve, 2-RC-MOV-2586, in Mode 3 while shutting down for refueling.

**Summary**
The activity is to energize and open the "B" RCS Loop Bypass valve (2-RC-MOV-2586) in Mode 3 to flush the 8" bypass line. It is expected that this activity will reduce the dose rates for maintenance activities planned for the "B" Loop during the refueling outage.

Tech Spec Considerations

With the bypass valve open the B RCS loop will be conservatively considered INOPERABLE as a heat removal method due to slightly reduced flow through the core (TS 3.4.1.2.a Action: Restore prior to Mode 2)

RCS Loop Flow Reactor Trip TS 3.3.1.1 Item 12 will be INOPERABLE since it will not be sensing flow through the core (due to bypass flow through 2-RC-MOV-2586) Action: Secure bypass flow prior to Mode 1.

TS 3.8.2.7, (TRM Table 9.2-1) requires the supply breaker to 2-RC-MOV-2586 (2-EE-BKR-2H1-2S-F3) to be open. Action: Deenergize in 72 hours. Note: TS 3.8.2.5 (TRM Table 5.1-2) requires the breaker to be OPERABLE.

TS 3.8.1.1, The EDG loading does not take into account the subject MOVs. However, MOVs are momentarily energized devices and are only considered in EDG loading during the first few minutes of EDG loading for accident/loop initiated actuations. Also, the valve is manually operated, and the brief energization of this valve in Mode 3 will not impact the EDG loading. It will be placed back into its normally de-energized condition once this evolution is over. 2H EDG will be considered OPERABLE while 2-RC-MOV-2586 is energized.

Non LOCA Analysis Considerations

Currently, Unit 2 is operating with about 308,000 gpm total vessel flow, as opposed to a safety analysis thermal design minimum flow of 278,400 gpm for Mode 3 accidents. [Note that the 295,000 gpm required minimum flow in Technical Specification Table 3.2-1 is only applicable in Mode 1]. Therefore there is more than adequate flow margin to accommodate the expected effect of the bypass line being open. Since the available flow margin (29,600 gpm) is well in excess of the estimated flow penalty for opening the bypass line (<17,000 gpm), and the RCS remains intact, all of the HZP non-LOCA accident analyses presented in UFSAR Chapter 15 remain bounding.

LOCA Analysis Considerations

With 2-RC-P-1B in service and 2-RC-MOV-2586 open, there is a potential path between the 'B' loop cold and hot legs through which ECCS flow can bypass the core, making it less effective for core cooling. It is expected that ECCS flow injected into 'B' loop will still aid in maintaining overall RCS coolant inventory. With the "B" RCP shut down, the "B" cold leg cooling capability is unchanged with the bypass valve open. The evaluation of this situation for postulated LOCA events is presented below. With the bypass valve open in Mode 3, the ECCS operability requirements of TS 3.5.2 are satisfied, ensuring that two independent ECCS subsystems are operable and capable of automatically injecting upon receipt of a safety injection signal. This would provide, at a minimum, the flow from one LHSI pump and one charging pump.

LBLOCA - The ECCS flow bypass is only a concern if 'B' loop is one of the intact loops, since design basis LBLOCA analyses assume all injected flow is lost from the broken loop. The minimum flow requirements for mitigating a LBLOCA can be determined from Attachment 2 of Emergency Operating Procedure 2-

ECA-1.1, entitled Minimum SI Flow Rate Versus Time After Trip. This figure is based upon time after trip, assuming initial hot full power conditions, and defines the flow required to remove core decay heat. At one minute after trip, a minimum flow of approximately 640 gpm is indicated. The cooling requirements under the present situation are significantly less than this, since the initial condition is Mode 3. Even if it is assumed that all of the flow injecting into 'B' loop bypasses the core, and all ECCS flow through either 'A' loop or 'C' loop is lost through the break, flow would still be injected from one LHSI and one charging pump branch line. The sum of these flowrates exceeds the 640 gpm necessary for decay heat removal. This cooling capability would provide abundant flow to maintain any core heatup within the acceptance criteria of 10CFR50.46.

SBLOCA - WCAP-12476, "Evaluation of LOCA During Mode 3 and Mode 4 Operation for Westinghouse NSSS," documents an evaluation of Westinghouse plant response to postulated LOCA events in Mode 3 and 4. It was concluded that for three loop plants, response would be within the acceptance criteria of 10CFR50.46 if flow from one charging pump was initiated at 10 minutes. Accumulators were assumed to be unavailable for the Mode 3 evaluation in WCAP-12476 since it was assumed that RCS pressure was below the point at which accumulator MOVs are isolated (1000 psig for NAPS).

Summary

A review of the UFSAR Chapter 15 accidents indicates that the current accident analyses remain bounding for the proposed condition. This is based on the following:

- For the non LOCA accidents, the RCS remains intact and therefore the FSAR analysis remains bounding by virtue of the flow margin discussion above.
- For the LOCA events, the effect of the bypass line on SI flow delivered to the core is acceptable. If we assume that the effect of the bypass line would result in SI flow being delivered to only one loop (broken loop spills and loop B injection bypasses the vessel and core) the delivered flow to the intact line would still be adequate to remove decay heat at shutdown, as discussed above.

For these reasons, the consequences of accidents considered are not increased. The RCS pressure boundary is not affected; therefore, the probability of occurrence of a Loss of Coolant Accident is not increased. Affected equipment is being operated as designed; therefore, the activity does not create the possibility of accidents not previously considered. Based on the above, an unreviewed safety question does not exist. Since the activity will reduce the dose rates for planned maintenance in the "B" loop room without jeopardizing safe station operation in Mode 3, the activity should be allowed.

**01-SE- PROC-05**

**Description**
2-OP-5.7, Operation of the Pressurizer Relief Tank (PRT)
Install a temporary hose between an SI accumulator vent and a drain off of the RHR relief valve discharge line.

**Summary**
Due to flow restrictions that exist in the installed nitrogen supply line, it is desired to provide an additional controlled source of nitrogen to the PRT to provide a slight overpressure to the RCS as part of the normal RCS draindown from 28% to 74 inches. The proposed procedure change will use a hose rated for at least 100 psig to supply nitrogen from the "A" SI accumulator vent to the RHR relief valves discharge line and then to the PRT. This configuration will allow the control room operator to control RCS overpressure by opening the pressurizer PORV and controlling the makeup flow of nitrogen to the SI accumulator with its supply HCV.

Personnel safety will be ensured by maintaining the nitrogen supply pressure from the accumulator at approximately 50 psig and by physically restraining the hose at the connections in accordance with standard Operations practice. This will prevent the the hose from whipping. In addition, a check valve will be provided on the jumper discharge side which will limit the amount of radioactive gas that could be released from the PRT if the jumper hose were to be cut or damaged.

Equipment safety is provided by at least one pressurizer PORV and its associated block valve maintained open and the PRT rupture disc. The nitrogen pressure to the RCS will be limited to less than or equal to 50 psig. This pressure will provide a back pressure to the RHR relief valves which will tend to increase the pressure at which those valves will lift. However, the main RCS overpressure protection will still be the PRT rupture disk which will be unaffected by the additional nitrogen makeup source.

An unreviewed safety question is not created because:
(1) The probability of an accident or malfunction previously evaluated in the SAR occurring is not increased. The change does not introduce any accident initiators. The unit is shutdown and will be in Mode 5 while this change is active.
(2) The consequences of any accident or malfunction previously evaluated in the SAR are not increased. No fission product barriers are compromised by this change. The unit is shutdown and will be in Mode 5 while this change is active.
(3) The possibility of creating a new accident or malfunction has not increased. The change will be installed by qualified personnel and using appropriate safety guidelines. The control room operator will have control of the nitrogen supply via the SI accumulator makeup HCV. A jumper hose rupture does not breach the RCS boundary because of the installed check valve.

Because the change is not an undue risk to personnel safety or reactor safety, this procedure change should be allowed.

**01-SE- PROC-06**

**Description**
0-OP-16.11, Makeup to Unit 2 RWST From The Boron Recovery Tanks
0-OP-16.11 is a new procedure to support the recovery of borated water that is otherwise lost during a refueling outage. A Boron Recovery Tank will be used as a source of makeup water to the Unit 2 RWST.

**Summary**
0-OP-16.11 is a new procedure designed for transferring water between a Boron Recovery Tank and the Unit 2 RWST. During refueling outages, a significant quantity of borated water will collected in the in-service Boron Recovery Tank. Recovery of this borated water back to the RWST will result in cost savings and reduce the amount of water that must be discharged back to the environment. The procedural actions are similar to other RP alignments such as transferring refueling cavity water back to the RWST and the maintenance related activities previously evaluated in 96-SE-PROC-05 and -32.

The overall operation of all involved systems will not be altered. Boron concentration of the RWST is maintained within allowable limits by calculations prior to the initiation of the transfer and by sampling afterwards. A significant portion of the RP piping is non-seismic and it will be aligned to the RWST when the RWST is required to be operable. This condition has been previously evaluated in 96-SE-PROC-25 for Engineering Transmittal CE-96-014 which addressed the non-seismic characteristics of the RP system.

These contingency actions will be put in place to protect the plant from a loss of the RP system due to a seismic event. These contingency actions are described in the Engineering Transmittal and are included in the procedure. RWST boron concentration and level are maintained within their Technical Specification allowable limits by administrative requirements that are included in the procedure. These actions will ensure enough borated water remains in the RWST to perform necessary functions. Design features prevent the loss of the entire spent fuel pit or reactor cavity during a seismic event where the RP system is lost.

Accident precursors are not affected by contingency actions designed to isolate the RP system from safety related systems necessary to respond during the postulated accident. Since these actions cannot affect the accident precursors, the probability of any postulated accident or loss of equipment is not altered. Therefore, the probability of occurrence of accidents or malfunctions of equipment previously evaluated in the SAR is not increased.

The contingency actions are designed to isolate the non-seismic piping of the RP system from any system needed during the postulated accident. The administrative requirements to calculate and sample the RWST ensure that it remains fully operable. Since these contingency actions and administrative requirements ensure the continued availability and operability of all necessary systems, the consequences of any postulated accident have not been altered. RP system contingency actions will not adversely affect equipment required to mitigate malfunctions of equipment previously analyzed. Therefore, the consequences of accidents or malfunctions of equipment previously analyzed are not increased.

The overall operation of the RP system and the RWST is not altered. The non-seismic portions of the RP system will be isolated in the event of a seismic event and RWST boron concentration and level are maintained within required limits. Therefore, existing analysis is still valid and no other accidents are postulated. The overall operation of the RP system and the RWST is not altered. Therefore, the probability of occurrence or consequences of accidents or malfunctions of equipment not previously analyzed are not increased.

RP is not a Technical Specification system. Contingency actions and administrative requirements will ensure that Technical Specification systems remain fully operable during any postulated seismic event. Therefore, the margin of safety as reflected in the bases of the Technical Specifications is not reduced.

Given the above conclusions, no unreviewed safety question exists.

**01-SE- PROC-07**

**Description**
2-OP-16.2 Revision 15-P1
This TM change is being developed to allow recovery of loop stop valve leakage from the PDTT pump discharge to the RP system. This procedure will allow the installation of a hose and a check valve between the discharge of the PDTT pump and a vent valve on the RP system back to the Refueling Cavity.

**Summary**
A temporary modification is to be added to procedure 2-OP-16.2 as a method for loop stop valve leakage recovery. This procedure will allow the installation of a hose and a check valve between the discharge of the PDTT pump and a vent valve on the RP system to the Refueling Cavity. This change will allow recovery of the leakage when the RHR system is unavailable.

The difference in elevation between the connection at the PDTT pump discharge and the Refueling Cavity water level is 76 feet. The PDTT pumps are rated for 120 feet of discharge head at a flow rate of 60 gpm. The rated discharge pressure of the PDTT pumps is 53 psig. The procedure allows the use of both PDTT pumps if required. Operating both of the PDTT pumps in parallel will result in a minimal increase in the discharge head of the pumps; therefore, using a hose that is rated for 250 psig is acceptable.

The temporary modification will be leak checked when placed in service. Failure of the hose would result in water from the PDTT being pumped on to the containment floor until the leak is terminated. The Loop Stop Valves will be closed during the period that this temporary modification is installed which will limit any leakage to the PDTT. Refueling Cavity level will be preserved by the check valve that is to be installed near where this Temporary Modification ties into the RP system. This procedure will only be used during a de-fueled condition, so the safety significance is negligible.

Failure of the temporary check valve could cause a reduction in Refueling Cavity and Spent Fuel Pit level; however, this Temporary Modification will normally be used with the transfer canal gate valve closed. Maintaining the transfer canal gate valve closed is not a procedural requirement and its configuration does not affect this evaluation. This TM will only be installed when the unit is de-fueled and it will be removed prior to core on-load. The transfer canal gate valve is normally closed in this condition.

An Unreviewed Safety Question does not exist based on the following:

Implementation of this TM will not increase the probability of occurrence of an accident or malfunction of equipment previously analyzed. Failure of the TM will not affect equipment and systems used to respond to the considered accidents. The ability to provide makeup to the RCS and cavity are not reduced by implementing this TM. Implementation of this TM has no effect on systems or equipment required to provide backup cooling to the reactor vessel or spent fuel pit. The design function of the RP system will not be adversely affected by this TM. Therefore, implementation of this TM will not increase the consequences of an accident or malfunction of equipment previously analyzed.

The TM will be installed with no fuel in the Reactor Vessel, when the core cooling function of RHR is not required. Catastrophic failure of the TM could result in a loss of Cavity inventory; however, even if the transfer canal gate valve were open to the Spent Fuel Pool, the leakage would be detected locally or remotely from MCR indications and would be isolated locally prior to the development of any adverse inventory condition. The TM will not interface with other systems that are required for any safety function. Therefore, implementation of this TM will not create the possibility of an accident or malfunction of equipment not previously analyzed.

Implementation of this jumper has no effect on the basis section of the Tech Specs. Therefore, the margin of safety as defined in the bases to the Tech Specs is not reduced.

**01-SE- PROC-08**

**Description**
2-MOP-7.31
This procedure change provides an alternative method to fill the Safety Injection (SI) Accumulators from the Refueling Purification (RP) system while the RP system is lined up in one of the following configurations:
1) Recirc to the Unit 2 RWST
2) Unit 2 Cavity to Cavity
3) Pump down of the Unit 2 RCS to the Unit 2 RWST

**Summary**
The normal method of filling an SI Accumulator is from RWST via the Hydrostatic Test Pump. Filling three accumulators using the normal method is slow and designed for normal makeup at power. It is desired to fill the SI Accumulators in a more timely manner. The proposed changes will allow the SI Accumulators to be filled by installing a temporary modification and fill from the RP system which is lined up to take a suction from either the Reactor Cavity or Unit 2 RWST.

The first method (2-MOP-7.31, Section 5.13) involves filling the SI Accumulators from the RP System with the RP System suction source from the Unit 2 Cavity. A temporary hose is installed between the RP pump discharge, downstream of the RP Filters and Ion Exchanger, and the SI Accumulator fill line downstream of the Hydro Test pump. The normal Accumulator fill line trip valves control which Accumulator is being filled. The water will be supplied from the cavity, and the fill rate will be controlled by throttling at the RP pump discharge connection. The RP system parameters (RP Filter and Ion Exchanger D/P) will be monitored and maintained within their normal operating ranges during the evolution. The Accumulator fill rate can also be adjusted by throttling the RP discharge flow to either the Unit 2 RWST or the Unit 2 Cavity, depending on the RP system configuration.

The second method (2-MOP-7.31, Section 5.14) involves filling the SI Accumulators from the RP system with the RP system suction source from the Unit 2 RWST. Temporary hoses are installed between the RP pump discharge, downstream of the RP Filters and Ion Exchanger, and the Accumulator drain lines through the Type A test air line and trip valves. With the temporary hoses installed and the RP system on recirculation to the Unit 2 RWST, the Accumulator fill rate will be controlled by throttling at the RP pump discharge connection. The RP system parameters (RP Filter and Ion Exchanger D/P) will be monitored and maintained within their normal operating ranges during the evolution.

This procedure is only valid when Unit 2 is in Mode 5, 6, or defueled. The RP system will be initially configured in one of the following line ups:
- Unit 2 Cavity to Cavity
- Pump down of the Unit 2 RCS to the Unit 2 RWST
- Recirc to the Unit 2 RWST

The RP system as described in the Safety Analysis Report allows for the above mentioned configurations. The boron concentration of the RP suction source must be between 2200 and 2400 ppm boron and the water must meet all other Chemistry requirements for SI Accumulator water. If the RP System is aligned to the RWST, then the limitations of 2-OP-16.2 must be met. If a seismic event occurs, an operator must be available to be immediately dispatched to close the isolation valves. Step 5.14.3 verifies that RP is aligned on recirc to the RWST.

The probability of occurrence of accidents is not increased. This activity may be performed when the RWST is required to be operable. The contingency actions designed to isolate the RP system from safety related systems and the demonstrated ability to maintain the RWST fully operable at all times do not affect the event precursors. Since these actions cannot affect the event precursors, the probability of any postulated accident is not altered.

The consequences of any postulated accidents is not increase. The RWST will remain fully operable as defined in the Technical Specifications. The contingency actions ensure the continued availability of all necessary systems; therefore, consequences of any postulated accident have not been altered. This activity will be performed when the SI Accumulators are not required to be operable. There is no postulated accident during this evolution that requires operability of the accumulators.

This activity does not create the possibility of a different type of accident. The overall operation of the RP system, the RWST, and the SI Accumulators is not altered in any way. The non-seismic portions of the RP system will be isolated in the event of a seismic event. Calculations and sampling ensure that the SI Accumulators will be operable when required by the Technical Specifications. Therefore, all existing analysis is still valid and no other accidents are postulated.

**01-SE- PROC-09**

**Description**
2-MOP-5.98 Rev. 0, Returning One or More Reactor Coolant Loops to Service Following Maintenance Using Backfill Method with the Reactor Head Removed
This new procedure allows isolated and drained reactor coolant loops to be returned to service using by backfilling through the loop stops from the active portion of the RCS while the reactor head is removed. Installation of temporary modifications to bypass the loop stop valve interlocks is included in this procedure.

**Summary**
2-MOP-5.98 Rev. 0 will be the procedure controlling this evolution. This new procedure was created to return one or more drained reactor coolant loops to service following maintenance using the backfill method with the reactor head removed. This will take advantage of the large volume of water in the cavity as a source of makeup. This will reduce the amount of water needing to be pumped back to the RWST. The procedures provide the necessary controls for temperature and boron concentration of the isolated loop to ensure the required shutdown margin is maintained if fuel is in the vessel.

Specifically, the procedure ensures the following conditions are maintained: a) Seal injection will be supplied to the RCP if the loop has been verified drained (using PDTT inleakage rate), and the boron contration of the seal injection water is above the TS 3.9.1. b) After defeating the loop stop valve interlocks via jumper installation, the applicable cold leg loop stop valve may be opened provided that the loop is drained, the pressurizer contains at least 450 cubic feet of water (32% cold cal level), and a source range neutron flux monitor is operable. c) Backfilling of the loop may proceed if the pressurizer level is maintained above 32 % cold cal level, the source range neutron flux count rate is no more than a factor of 2 above the initial count rate, and seal injection is maintained above the required boron concentration. d) When the isolated loop is full, the loop stop valves can be fully opened when the boron concentration of the loop is in spec, and no more than two hours have passed since the loop was backfilled. This backfill technique was previously evaluated under 99-SE-OT-32, and these required conditions are properly controlled by the proposed procedure, 2-MOP-5.98 Rev. 0. This evaluation concentrates on the temporary modifications that will be required to defeat the loop stop valve interlocks. Safety Evaluation 00-SE-PROC-21, written for 1/2-MOP-5.97 (RETURNING ONE OR MORE REACTOR COOLANT LOOPS TO SERVICE FOLLOWING MAINTENANCE USING BACKFILL METHOD) previously evaluated temporary modifications being used in this procedure.

If fuel will be in the vessel, core onload will be complete, but other core alterations will be allowed. This makes evolutions such as gap testing and core map video activities possible while filling the loops. Technical Specifications will be complied with by maintaining adequate boron concentration and shutdown margin, and 23 feet will be maintained above the reactor pressure vessel flange at all times.

RCS Loop Stop Valve interlocks are designed to ensure that an accidental startup of an undrained, unborated and/or cold, isolated reactor coolant loop results only in a relatively slow reactivity insertion rate. The interlocks perform a protective function using two independent limit switches to verify that the hot leg loop stop valve is open, two independent limit switches to verify that the cold leg loop stop valve is full closed, and two independent flow switches to verify that bypass flow around the cold leg loop stop valve is greater than 125 gpm for 90 minutes. (The flow verifies that the pump is running, the bypass line is not blocked, and the valves in the bypass line are open). Additionally, the hot leg loop stop valve is prevented from opening unless the cold leg valve in the same loop is fully closed.

It is desired to partially open the loop stop valves on one loop at a time to support backfilling a drained loop. After an initially drained loop is filled from the RCS in this manner, the loop is no longer considered to be isolated. Thus, the requirements for returning an isolated and filled loop to service are not applicable, and the loop stop valves may be fully opened without restriction but within two hours of completing the loop backfill evolution. This Safety Evaluation considers a Temporary Modification that would allow bypassing the protective circuitry as needed to allow opening of the hot and cold leg loop stop valves. To support this evolution, the restrictions imposed by Technical Specification 3.4.1.6 will ensure that: 1) no potential is created for the introduction of unsampled water from the loop to the core after the evolution; 2) adequate RCS

inventory for core cooling is maintained throughout the evolution; 3) no potential for an undetected boron dilution as a result of mismatch between the boron concentration of the makeup stream and the RCS is created. 2-MOP-5.98 maintains the breakers for the subject valves with jumpered interlocks locked open until the TS restrictions are satisfied. Therefore, installing the proposed Temporary Modifications does not alter the bases of diminishing the potential for uncontrolled positive reactivity addition or loss of decay heat removal.

Additionally, the UFSAR analyzed condition for startup of an inactive loop with the cold leg loop stop valve initially closed states: "Even with the assumption that administrative procedures are violated to the extent that an attempt is made to open the loop stop valves with 0 ppm in the inactive loop while the remaining portion of the system is at 1200 ppm, the dilution of the boron in the core is slow. ... For these conditions, the time for shutdown margin to be lost and the reactor to become critical is 16.4 min." As can be seen, there is plenty of time for the operator to identify the high count rate and to take appropriate actions.

No Unreviewed Safety Question exists because the probability of occurrence and the consequences of a startup of an inactive loop or inadvertent criticality accident are not affected. In addition, there are no postulated accidents or malfunctions that could be generated by the proposed activity.

**01-SE- PROC-10**

**Description**

VPAP - 2201, CH-97.100 Rev. 6, VPAP - 0306 Att.3 "CHEMCALC Ver. 2 Mod 5.

The change will implement a change of reactor coolant chemistry pH control from the current "coordinated" program [constant pH(t) = 6.9] to a "modified" program which allows the pH(t) to increase as the fuel cycle progresses from an initial pH(t) of 6.9 to a final pH(t) of 7.4. Currently lithium is controlled from near a maximum value of 3.5 ppm at the beginning of a fuel cycle to a value near 0.2 ppm at the end of a fuel cycle. The change to "modified" chemistry will not change the maximum lithium value at the beginning of a fuel cycle but will result in an end of fuel cycle lithium concentration near 0.7 ppm. An additional change is that the coordinated pH program was based on RCS Tavg(305.5 degrees Celsius) and the new program will be based upon a reference temperature of 300 degrees Celsius.The change will also implement new control bands for the lithium concentration in accord with EPRI Primary Water Chemistry Guidelines, Rev. 4, March 1999.

Operation with modified chemistry is expected to result in less crud on the fuel and lower dose rates than coordinated chemistry. Industry data confirms this expectation with a reduction of ~ 20% for modified chemistry compared to coordinated chemistry. The calculation of pH based on a fixed reference temperature is based on the observation that the temperature dependence of pH is primarily controlled by the strong variation in the dissociation constant of water, Kw, with temperature. It will eliminate lithium addition and removal operations that would be demanded when the plant ramps due to this sensitivity of Kw to temperature. It also facilitates comparisons to different plants and to the historical corrosion product solubility data base, which was developed for 300 degrees C.

In summary, this change will result in reduced corrosion of primary system components and lower dose rates in the plant. It is the same type of reactor coolant chemistry control in use at Surry Power Station, as well as a number of other stations in the industry

This change would be implemented for North Anna Unit 2 at startup of Fuel Cycle 15 (Spring 2001) and for North Anna Unit 1 at startup of Fuel Cycle 16 (Fall 2001).

**Summary**

There are no unreviewed safety questions determined. Major issues considered included the fuel cladding integrity, materials of construction of the RCS (primarily cracking of Alloys 600), post LOCA sump pH analyses, and the development of Axial Offset Anomaly. None of the items mentioned previously are expected to lead to any problems or conditions that have been previously analyzed nor are they expected to produce any new scenarios not previously analyzed.

Paraphrasing the EPRI Primary Water Chemistry Guidelines, Revision 4 - Crack growth rates of Alloy 600 material are not systematically dependent upon water chemistry ( including pH and lithium) with the limits of the PWR Water Chemistry Guidelines. The effect of chemistry on crack growth rate was second order compared to heat to heat variability. pH in the operating range has relatively small effect on Primary Water Stress Corrosion Cracking (PWSCC) of Alloy 600 materials. PWSCC occurs typically in highly stressed regions (U-bends and tube sheet expansion transitions in steam generators with susceptible Alloy 600 tubing, Alloy 600 tube plugs, and vessel head and pressurizer penetrations. For Alloy 600, there is an approximate 20% decrease in characterisitic life with increasing lithium from 0.7 to 3.5 ppm and little additional effect of lithium above 3.5 ppm. The station already operates within this range of lithium and no deleterious impact has been seen. The effect of lithium is small compared to more dominant effects of stress, heat to heat variations, and temperatures and only becomes significant if there is long term operation at or above 3.5 ppm lithium, which is not expected for this pH program change. In summary, chemistry regimes with initial lithium concentrations up to 3.5 ppm should not cause a significant increase in Alloy 600 crack growth rates.

The actual pH of the coolant system has no effect on fuel cladding corrosion but the pH and the amount of lithium do have an impact on fuel crud deposition which in turn can have impacts on fuel cladding corrosion. One of the important principles of reactor coolant pH control is to not operate below a pH(t) of 6.9. Operation below pH(t) 6.9 can lead to the formation and deposition of significant core crud.

Additionally, another principle of reactor coolant pH control is to operate at pH(t) 6.9 at the beginning of extended fuel cycles. Both of these principles are addressed by this pH change proposal. In terms of fuel performance, the difference in strategies between coordinated and modified pH control programs have little effect on cladding corrosion when the effects of coolant chemistry on crud deposition are accounted for, particularly for the more corrosion resistant cladding materials now being used for current generation fuels. The move to a higher pH during the fuel cycle as proposed, will reduce the amount of core crud deposits and thus reduce the impact on the cladding. Additionally, reductions in core crud also reduce the likelihood of Axial Offset Anomaly developing.

Nuclear Analysis and Fuel has determined that this proposed pH change has no impact on post LOCA sump pH analyses previously performed.

This change is a change to the existing reactor coolant system chemistry control program for pH(t) control. The pH(t) will be allowed to increase from an initial value of 6.9 at the beginning of a fuel cycle with lithium maintained at ~ 3.5 ppm to a final value of 7.4 with a final lithium value of ~ 0.7 ppm. This compares to the current program which maintains a constant pH(t) of 6.9 throughout the fuel cycle and allows lithium to vary from ~ 3.5 ppm to 0.2 ppm. Cracking of Alloy 600 materials is not expected. Water chemistry has a second order effect on this mode of cracking. No corrosion issues are expected since higher pH will result in lower corrosion and dose rates because fewer corrosion products are expected to be generated. This in turn will result in lesser amounts of activated corrosion products such as Co-58. Because higher pH results in less corrosion, the possibility of Axial Offset Anomaly development is reduced as well. The higher pH proposed has an insignificant impact on post LOCA sump pH analyses.
Per Technical Report NE-1267, Rev. 0, a Westinghouse assessment of the proposed chemistry change and the temperature change concluded that for the current cladding material a significant amount of margin remains to the design limit. The projected end of life corrosion levels are also small enough that no impacts are expected on other fuel rod design criteria that may be impacted by the thermal effects of high corrosion, such as rod internal pressure.

Therefore, it is determined that no unreviewed safety question exists for this change.

**01-SE- PROC-11**

**Description**
Procedure 0-OP-4.13, Rev. 0 "Inspection of Fuel Assembly Thimble Sleeves"
Procedure 0-OP-4.13 provides instructions for the visual inspection of irradiated fuel assemblies which may possibly have degraded thimble sleeves. Fuel handling performed under this procedure consists of lifting the fuel assembly a maximum of four (4) feet, while the assembly remaining inside the spent fuel pool rack cell, in order to perform the visual inspections. Lifting of the fuel assembly is performed using the station's spent fuel handling tool (not the "nozzleless" handling tool). Limitation of the height of the lift will be accomplished by the use of a sling in series with the hoist hook and the handling tool.

**Summary**
As a result of Plant Issue PI N-2001-0886 "Dropped Fuel Assembly G45", all fuel assemblies with 304 SS thimble sleeves are considered susceptible to the failure mechanism (Intergranular Stress Corrosion Cracking, IGSCC) and are restricted from movement by normal means. Successful visual inspection of the thimble sleeves will permit reclassification of unaffected fuel assemblies to allow movement with normal fuel handling tools.

Procedure 0-OP-4.13 provides instructions for the visual inspection of irradiated fuel assemblies which may have degraded thimble sleeves. As such, it is assumed that during the course of the visual inspection a fuel assembly with degraded sleeves may experience a top nozzle separation event (similar to G45) and fall back into its spent fuel pool rack cell location. This procedure limits the upward movement of the fuel assembly to be inspected to four (4) feet. Analysis provided in Reference 2 concludes that no fuel rod failures will occur should a nozzle separation event occur and the fuel assembly falls from this height.

The probability of occurrence or the consequences of an accident or malfunction of equipment important to safety previously evaluated in the safety analysis report is not increased as a result of the use of this procedure. The Fuel-Handling Accident Outside Containment accident is defined as "...dropping of a spent fuel assembly onto the spent fuel pool floor or the racks that hold the spent fuel." Inherent in the treatment of such an event as an accident is that there is an associated release of fission products. For North Anna the UFSAR states: "it is conservatively assumed for this analysis that the cladding of all the fuel rods in one assembly rupture." The fuel assemblies being inspected may possibly have degraded thimble sleeves, which would increase the potential for separation of the top nozzle from the remainder of the fuel assembly, allowing the fuel assembly to drop. However, the procedure permits the fuel assembly being inspected to be lifted a maximum of four (4) feet. The analysis of Reference 2 concludes that no fuel rods will rupture for a fall of this height into the spent fuel pool rack cell. As no fuel rods are failed and no fission product release occurs, a nozzle separation event which occurs during the completion of this procedure would not be construed as a fuel handling accident. In addition, the minimum cooling time of any susceptible fuel assembly (time since discharge from the reactor) would preclude the presence of I-131. Therefore, the conditions for a Design Basis Accident are not present. All fuel handling will be performed in accordance with this procedure and existing fuel handling procedures insuring that all of the bounding assumptions of the Fuel Handling Accident Outside Containment, including requirements for spent fuel pool crane travel, water level, and fuel building ventilation, remain valid. The sling used to limit the upward movement of the fuel assembly to four (4) feet meets the safety requirements for hoisting cables in Reference 4 (safety factor of five (5)). Therefore, there is no increase in the probability of malfunction of any fuel handling equipment. This insures there is no increase in the probability of occurrence or consequences of this accident.

The possibility for an accident or malfunction of a different type than any evaluated previously in the safety analysis report is not increased. Fuel assembly video inspection involves the nonintrusive use of simple hand held tools to inspect a single fuel assembly. As such, there is no possibility that an accident of a different type than previously evaluated in the SAR will be created. As discussed above, it is postulated that a nozzle separation event may occur. Analysis has concluded that no fuel rods will fail (rupture) and no radioactive releases will occur as a result of any such event. Analysis in Reference 3 concludes that the resulting stresses and strains on the spent fuel pool racks and the concrete of the pool floor are within the allowable code limits for the case of a fuel assembly dropped through a storage cell. As all fuel handling

will be performed in accordance with this procedure and existing fuel handling procedures, the limiting failure of any fuel handling equipment remains bounded by the Fuel Handling Accident Outside Containment described in the UFSAR.

The margin of safety as defined in the basis for any Technical Specification is not reduced. The margin of safety associated with the spent fuel pit crane travel and fuel building ventilation system, as described in the bases section of the Technical Specifications is based on the assumption that all of the radioactive material from the fuel pellet to clad gap of an irradiated fuel assembly is released to the spent fuel pool. As this and all other bounding assumptions for the Fuel Handling Accident remain valid, this margin of safety is not reduced.

**01-SE- PROC-12**

**Description**
New Procedures
1-MOP-31.35A, Removal of 1-FW-E-5A, 1-FW-E-6A, and 1-CN-DC-1A from service for maintenance
1-MOP-31.35B, Removal of 1-FW-E-5B, 1-FW-E-6B, and 1-CN-DC-1B from service for maintenance
2-MOP-31.35A, Removal of 2-FW-E-5A, 2-FW-E-6A, and 2-CN-DC-1A from service for maintenance
2-MOP-31.35B, Removal of 2-FW-E-5B, 2-FW-E-6B, and 2-CN-DC-1B from service for maintenance
These new procedures permit removal from service and return to service of selected Drain Coolers and Feedwater Heaters. These procedures were written to permit maintenance on these heat exchangers during plant operation.

**Summary**
MAJOR ISSUES:
It is sometimes desirable to take a Feedwater Heater or Drain Cooler out of service during plant operation in order to perform repairs such as tube plugging or to replace leaking relief valves. During the year 2000, these procedures (MOPs for Unit 1 and Unit 2) were drafted in order to provide more complete guidance on removing 5$^{th}$ and 6$^{th}$ point FW heaters and drain coolers from service and returning them to service following maintenance. Note that these procedures may be performed with the Main Turbine in operation. These procedures do not permit complete isolation of their associated heat exchangers. High energy fluid will remain on the shell side of the heat exchangers. These procedures provide the steps to align the heat exchangers for Condensate side maintenance.

The primary plant operational concerns are related to system transients experienced during removal and return to service of these heat exchangers. One concern is the rate of heat-up and cool-down of these heat exchangers during such evolutions. Another concern is that the turbine load must be reduced before taking feedwater heaters out of service. This concern is described in the Westinghouse Steam Turbine Technical Manual, 59-W893-00100, I.L. 1250-4116, page 15, Section VI, Feedwater Heater Ops.

JUSTIFICATION:
Implementation of these new procedures should be permitted, since they are in compliance with the Technical Specifications, the Safety Analysis Report, and the design basis requirements of the Unit 1 and Unit 2 Main Turbines and their associated plant systems. The SAR does not provide sufficient level of detail to describe such equipment operations.

Removal of Feedwater Heaters and Drain Coolers is commonly practiced in the industry and isolation valves are installed for this purpose. The Vendor Technical Manual (U1: 59-W893-00100, U2: 59-W893-00095) suggests limitations on removing feedwater heaters from operation. Namely, turbine power must be reduced from full power, turbine vibrations must be monitored, and heatup and cooldown rates of heat exchangers must be observed. These limitations are included in the Precautions and Limitations section of the new procedures. The overall operation of associated plant systems and equipment, including Condensate, Feedwater, and the Main Turbine remains unchanged.

UNREVIEWED SAFETY QUESTION ASSESSMENT:
1. Condition does not increase the probability of occurrence or the consequences of an accident or malfunctions of equipment important to safety and previously evaluated in the Safety Analysis Report.

   All activities associated with these procedures are bounded by existing analysis. Failure of all associated piping and components is bounded by analysis of Minor Secondary System Pipe Breaks and Major Secondary System Pipe Rupture. In addition, these activities do not increase the probability of any turbine or main steam related accidents, since all of the turbine governor valves will still be capable of closure from turbine trip signals.

2. Condition does not create a possibility for an accident or malfunction of a different type than was previously evaluated in the Safety Analysis Report.

Providing specific procedures for removal and return to service of these heat exchangers will allow for better control of these evolutions. All accidents that involve the turbine require isolating main steam from the turbine to control and limit the accident. The steam isolation capability of the main turbine has not been affected by this change. Further, failure of all associated piping and components is bounded by analysis of Minor Secondary System Pipe Breaks and Major Secondary System Pipe Rupture.

3. Condition does not reduce the margin of safety of any part of the Technical Specifications as described in the bases section.

   There are no Technical Specifications directly relating to the feedwater heaters or drain coolers. Technical Specification margin as it relates to the main turbine is concerned with isolation of steam flow from the turbine in the event of a turbine trip or overspeed condition. Neither of these is affected by the removal of feedwater heaters or the drain cooler from service during power operations. Thus, the evolutions controlled by the proposed new procedures do not reduce the margin of safety of any part of the Technical Specifications as described in the Bases Section. Removal of associated heat exchangers from service will result in a decrease in feedwater temperature and a corresponding insertion of positive reactivity. While there is a potential for a slight increase in reactivity due to this reduction in feedwater temperature, this is adequately addressed in these new procedures and does not impact the margin of safety.

**01-SE- PROC-13**

**Description**
0-OP-52.1, Rev 3 "Domestic Water System"
Three changes are proposed by this revision.
An electrical jumper to defeat the alternating circuits input to a Domestic Water (DW) Booster Pump when it is removed from service and restore the alternating circuits input when the DW Booster Pump is returned to service. Noun names are being added to procedure steps to clarify and improve usability. A Procedure step to cross-tie Well House 2 well supply with other Wells is being deleted since check valve, 1-DW-7, located in the discharge line of Well 2 prevents this action.

**Summary**
This Safety Evaluation considers allowing the installation and removal of an electrical jumper that will defeat a Domestic Water (DW) Booster Pump's alternating circuit input in order to facilitate maintenance on a DW Booster Pump.

Two DW Booster Pumps are provided, one being a 100% spare, which deliver water to the DW Hydropneumatic Tank. The DW Hydropneumatic Tank's pressure and level are controlled by a combination pressure-level controller connected to the tank. The controller controls the operation of the DW Booster Pumps, the air compressors and vent valve. An Alternating Circuit is utilized to equalize the number of pump starts between the two DW Booster Pumps.

This jumper will allow the removal of one of the two DW Booster Pumps for maintenance. Removal of the alternating circuit's input to a DW Booster Pump that has been removed from service for maintenance will prevent the possible loss of the DW Hydropneumatic Tank level and pressure. The jumper will prevent the alternating circuit from trying to call for the start of a DW Booster Pump that has been removed from service, thus preventing the loss of the inservice DW Booster Pump and ensuring DW Hydropneumatic Tank level is maintained.

The Domestic Water (DW) System is described in Section 9.2.3.1 of the UFSAR. The DW system pressure is designed to be maintained between 40 and 60 psig by the pressure maintenance equipment. Two DW Booster Pumps are provided, one as 100% capacity spare. Therefore, the removal of the alternating circuits input to a DW Booster Pump that has been removed from service for maintenance is acceptable to ensure the DW system remains operable.

CONCLUSION:

The jumper does not alter or affect the function or operation of the Domestic Water System. During a Design Basis Accident, the DW system would be lost since the lines are not seismically supported and the power supplies are not safety related. Therefore, the impact of the jumper during an accident is negligible.

The system does not provide any safety function required for safe shutdown or accident mitigation. The jumper does not alter the system function or performance. Therefore, the change does not increase the probability of an accident or malfunction previously evaluated in the UFSAR. Likewise, the change does not increase the consequences of an accident or malfunction previously evaluated. The change involves a simple jumper which will only be placed in service when a DW Booster Pump is removed from service for maintenance; therefore, no new accidents or malfunctions are created. The Domestic Water System is not required by the Technical Specifications. Thus no Technical Specification requirements are altered by the change, nor are new requirements necessitated. For these reasons, an Unreviewed Safety Question is not created, and the Temporary Modification should be allowed.

**01-SE- PROC-14**

**Description**

ET NAF 2001-0071, REV. 0, DESIGN BASIS ADEQUACY OF WESTINGHOUSE NOZZLELESS FUEL ASSMBLY HANDLING TOOL

0-OP-4.11, Rev. 0, NOZZLELESS FUEL ASSEMBLY HANDLING TOOL

Dominion and Westinghouse, the fuel vendor, have concluded that all fuel assemblies using Type 304 stainless steel guide thimble sleeves may be susceptible to separation of the top nozzle from the remainder of the assembly during fuel handling. North Anna Unit 1 fuel Batches 1 – 8 and Unit 2 fuel Batches 1 – 7 are in this population. A fuel handling tool, which does not require the availability of intact guide thimble sleeves, has been procured from Westinghouse to handle affected fuel assemblies. The Engineering Transmittal provides a review of the design basis adequacy of the tool. The Operating Procedure gives detailed instructions for assembly, operation, and maintenance of the tool.

**Summary**

The nozzleless fuel handling tool uses an alternative means of gripping the fuel assembly (collets that expand into the inner surface of the guide thimbles rather than lifting at the top nozzle). The UFSAR design requirements for the fuel handling system are:

1. Fuel-handling devices have provisions to avoid dropping or jamming of fuel assemblies during transfer operation.
2. Fuel lifting and handling devices are capable of supporting maximum loads under design-basis earthquake conditions.
3. Cranes and hoists used to lift spent fuel have a limited maximum lift height so that the minimum required depth of water shielding is maintained.

The tool meets these requirements, therefore, the frequency of occurrence of a fuel handling accident caused by failure of the tool has not been increased.

However, the nozzleless tool is slightly more complicated to use and maintain. It requires the use of a torque wrench to latch onto the fuel assembly and manual adjustment of the gripping collets. To address the increase in complexity, a step in Procedure 0-OP-4.11 (currently Step 5.2.14) calls for briefly stopping upward movement of the fuel assembly at approximately 12 inches to verify there is no slipping between the fuel assembly and the grippers.

Since the nozzleless fuel handling tool itself will not increase the frequency of occurrence of a fuel handling accident and procedural steps mitigate human performance concerns, use of the nozzleless fuel handling tool will not cause more than a minimal increase in the frequency of occurrence of this accident.

The nozzleless tool is more mechanically complex than the other tools. Maintenance, adjustment, and testing of the tool are required by the procedure, after the tool is assembled and on a periodic basis. Detailed steps in the procedure instruct the operators in completion of these activities. In addition, as noted above, when the tool is being used the procedure calls for briefly stopping upward movement of the fuel assembly at approximately 12 inches to verify there is no slipping between the fuel assembly and the grippers. Thus, there is no increase in the likelihood of occurrence of a malfunction of the fuel handling equipment in general and specifically the nozzleless fuel handling tool.

All fuel handling using the nozzleless tool will be performed in accordance with this procedure (0-OP-4.11). All bounding assumptions of the accident analyzed in the UFSAR (time since reactor operation and depth of spent fuel pool water) remain valid should the accident occur during fuel movement using the nozzleless tool. Therefore, the consequences of a fuel handling accident outside of containment are not increased. The limiting consequence of a malfunction of fuel handling equipment, and specifically the nozzleless fuel handling tool, is a fuel handling accident. Since the consequences of the fuel handling accident remain bounded by the UFSAR analyzes, the consequences of a malfunction of the fuel handling equipment are also not increased.

The use of the nozzleless fuel handling tool involves movement of fuel assemblies in the spent fuel pool only. Therefore, the only credible accident is the fuel handling accident. Use of the nozzleless tool does not create a possibility for an accident of a different type than any previously evaluated in the UFSAR. The nozzleless fuel handling tool uses a different means of latching to a fuel assembly than the "normal" handling tools. All other fuel movement operations are the same. Thus, use of the nozzleless tool does not create a possibility for a malfunction of an SSC important to safety with a different result than any previously evaluated in the UFSAR.

Use of the nozzleless fuel handling tool as prescribed in Procedure 0-OP-4.11 involves movement of fuel assemblies in the spent fuel pool only. Therefore, the only fission product barrier that could be affected is the fuel cladding. Use of the nozzleless tool to move fuel within the spent fuel pool has no impact on the integrity or any design basis limit that could affect the integrity of the fuel cladding.

Use of the nozzleless fuel handling tool to move fuel assemblies in the spent fuel pool does not result in any change in any method of evaluation described in the UFSAR. The current accident analysis (Fuel-Handling Accident Outside Containment), and its calculated consequences, remain bounding for this activity.

**01-SE- PROC-15**

**Description**
Fuel-Handling Accident Outside Containment

**Summary**
Procedure 0-OP-4.13 provides instructions for the visual inspection of irradiated fuel assemblies, which may possibly have degraded thimble sleeves. Fuel handling performed under this procedure consists of lifting the fuel assembly a maximum of four (4) feet, while the assembly remaining inside the spent fuel pool rack cell, in order to perform the visual inspections. Lifting of the fuel assembly is performed using the station's spent fuel handling tool (not the "nozzleless" handling tool). Revision 1 of the Procedure removes the requirement that the lift be accomplished using a sling in series with the hoist hook and the handling tool, thereby limiting the height of the fuel assembly lift. Henceforth, the limitation of the lift height is to be controlled administratively with the operator utilizing visual reference indicators marked on the fuel handling tool.

All of the fuel assemblies susceptible to the thimble sleeve cracking/failure (fuel batches N1B8/N2B7 and older) have been discharged from the reactor for a minimum of 20 months (since 3/12/2000). Should a nozzle separation occur with the fuel assembly be lifted above 4 feet, the possibility exists that a failure of some or all of the fuel rods may result.

For this evaluation the UFSAR accident "Fuel Handling Accident Outside Containment" and a malfunction of the fuel handling equipment were considered. The evaluation concludes:

1. There is no increase in the frequency of occurrence or the consequences of a fuel handling accident outside of containment. The requirement to perform the thimble sleeve inspection at a maximum height of 4 feet remains in the procedure. Reference 2 of the Safety Review/Regulatory Screen concludes that no fuel rods will rupture for a fall of this height into the spent fuel pool rack cell.
2. There is no increase in the likelihood of occurrence or the consequences of a malfunction of the fuel handling equipment. Lifting of the fuel assembly is performed using the station's spent fuel handling tool (not the "nozzleless" handling tool). The limitation of the lift height is to be controlled administratively with the operator utilizing visual reference indicators marked on the fuel handling tool. Use of these visual cues is normal operator practice when moving fuel. A malfunction of the fuel handling equipment could result in a fuel assembly being lifted to a height greater than 4 feet during completion of the inspection procedure. Should a nozzle separation occur with the fuel assembly be lifted above 4 feet, the possibility exists that a failure of some or all of the fuel rods may result. All bounding assumptions of the fuel handling accident outside containment analyzed in the UFSAR (time since reactor operation and depth of spent fuel pool water) remain valid.
3. There is no possibility that an accident of a different type than previously evaluated in the UFSAR or a malfunction of an SSC important to safety with a different result than any previously evaluated in the UFSAR will be created. This fuel assembly visual inspection involves the nonintrusive use of simple hand held tools to inspect a single fuel assembly lifted a maximum of 4 feet in the spent fuel pool rack cell. Only one fuel assembly is being handled at any given time. The limitation of the lift height is to be controlled administratively with the operator utilizing visual reference indicators marked on the fuel handling tool.
4. The only fission product barrier that could be affected is the fuel cladding. The possibility of a rupture of all of the fuel rods in the fuel assembly has been considered in the UFSAR (Fuel-Handling Accident Outside Containment). Completion of the inspection procedure does not result in a design basis limit for a fission product barrier as described in the UFSAR being exceeded or altered.
5. Visual inspection of fuel assemblies in the spent fuel pool does not result in any change in any method of evaluation described in the UFSAR. The current accident analysis (Fuel-Handling Accident Outside Containment), and its calculated consequences, remain bounding for this activity.

**SAFETY EVALUATION LOG**
**OTHER**
**2001**

| S.E. # | Unit | Document | System | Description | SNSOC Date |
|---|---|---|---|---|---|
| 01-SE-OT-01 | 1,2 | UFSAR FN 00-044 | | Eliminates the requirement for prior SNSOC review & approval of all procedural changes to NUREG-0612 safe load paths or exclusion areas, as currently stated in NAPS UFSAR Section 9.6.4.1. | 1-25-01 |
| 01-SE-OT-02 | 1,2 | UFSAR FN 01-001 | | Table 3C-2 (High Energy Lines [Outside Containment]) will be revised to correct operating pressure & temperature values listed in the table (identified in PI N-2000-0636-R2) & resolved in engineering transmittal CME-0047. | 2-01-01 |
| 01-SE-OT-03 | 2 | Tech Rpt NE-1266<br>FN 2001-004 | | Refueling & operation of North Anna Unit 2, Cycle 15, Pattern OX | 2-15-01 |
| 01-SE-OT-04 | 1,2 | TS Chg 385<br>UFSAR FN 00-042<br>1&2-ES-1.3 | | Implements the revised LOCA containment integrity analysis | 2-20-01 |
| 01-SE-OT-05 | 1,2 | UFSAR FN 00-046<br>ET CEE 00-0009, R. 0<br>ET NAF 01-0023, R. 0<br>0-OP-26.7, Rev. 7, P1 | | Allows RSST load shed circuit to be defeated with both units on-line for a period of up to 72 hours | 3-06-01 |
| 01-SE-OT-07 | 1,2 | UFSAR FN 00-047<br>Tech Rpt NE-1200<br>PI N-2000-2489-R2 | | Updates UFSAR Section 15.2.6 to reflect the current design bases that credit TS controls to preclude the preconditions for significant & uncontrolled reactivity insertion during the startup of an inactive loop. | 3-20-01 |
| 01-SE-OT-09 | 1,2 | UFSAR FN 00-049<br>0-PT-75.11<br>0-OP-49.1 | SW | Defines the required number of SW system reservoir spray arrays that are required to be operable to meet minimum design basis requirements. | 3-27-01 |
| 01-SE-OT-10 | 1,2 | UFSAR FN 01-010 | | Updates the description of zinc materials in the assumptions section of the containment hydrogen generation analysis. (Ref. PI N-2001-0488) | 4-17-01 |
| 01-SE-OT-11 | 1,2 | UFSAR FN 01-002 | | 1. Changes all references of Calgon biocide H-510 to the active chemical ingredient "Isothiazolin".<br>2. Eng. Calc ME-0567, Rev. 1, corrected several math errors, thus changing the maximum expected concentrations in the control room following a chemical spill. Clarifies hazard levels associated with zinc chloride & sodium molybdate. | 4-17-01 |
| 01-SE-OT-11<br>**REV. 1** | 1,2 | UFSAR FN 01-002 | | Replacement of Calgon biocide H-510 with NALCO 2894 Algaecide (copper-free) in the bearing cooling system.<br>ET N 01-108, Rev. 0, has been prepared as a supplement to calculation ME-0567 to document the acceptability of the NALCO 2894 algaecide with respect to control room habitability & provide the maximum expected chemical concentrations in the control room following a chemical spill | 6-21-01 |

**SAFETY EVALUATION LOG**
**OTHER**
**2001**

| S.E. # | Unit | Document | System | Description | SNSOC Date |
|---|---|---|---|---|---|
| 01-SE-OT-12 | 2 | UFSAR FN 01-013 | | Includes a revised 10 CFR 50.61 pressurized thermal shock screening calculation result for NAPS U2 reactor vessel weld material fabricated from weld wire heat 4278 (nozzle to intermediate shell weld 04A, OD 94%), with consideration given to Sequoyah U2 plant specific surveillance program data. | 5-01-01 |
| 01-SE-OT-13 | 1,2 | TS CHG 290A | | Includes a statement in Bases ¾.3.1 & ¾.3.1.2 to identify that a plant specific risk analysis was performed to support the increased AOTs & decreased surveillance frequencies for the functional units in Block 4 of referenced TS. | 5-08-01 |
| 01-SE-OT-14 | 1,2 | TS CHG 389 | | References to VEPCO will be changed in Units 1 & 2 operating licenses & TS to Dominion Generation Corporation | 5-17-01 |
| 01-SE-OT-15 | 1,2 | FN 01-007 | | Incorporates criteria & methodology of Generic Implementation Procedure (GIP) developed by the Seismic Qualification Utility Group & endorsed by the NRC. Also adds description of the in-structure median centered spectra that can be used in evaluations using the GIP. | 5-22-01 |
| 01-SE-OT-16 | 1,2 | UFSAR FN 01-011 | | Addresses discrepancies identified in Oversight Audit 01-02. Discrepancies consisted of an incorrect description of the foam hose stream capabilities for protection of fuel oil storage tank & pumphouse (9.5.1.2.1 & 9.5.1.3.1.2), an incorrect reference to a halon system that has been removed (9.5.1.4.1.2), and an unclear description of SCBAs use for fire fighting (9.5.1.2.4.4). | 5-29-01 |
| 01-SE-OT-18 | 1,2 | UFSAR FN 01-005 | | Updates Section 15.2.7 & associated tables & figures to incorporate a loss of load accident reanalysis | 5-31-01 |
| 01-SE-OT-19 | 1,2 | TRM Chg #44 | | Upgrades the TRM to capture revisions to the EQ Barrier Program over the last several years. Changes are administrative in nature. | 6-07-01 |
| 01-SE-OT-20 | 1,2 | Fuel Anomaly NDC01-9, Add. 2 | | Fuel Anomaly NDC01-9, Addendum 2, documents NAF's intention to conditionally remove the handling restrictions from fuel assemblies that were identified as susceptible to intergranular stress corrosion cracking of thimble sleeves based upon results of video inspections. | 6-21-01 |
| 01-SE-OT-22 | 1,2 | TRM chg 45<br>ET N-00-0138, R. 0<br>DR/PI N-99-0774<br>NAPS App. R .report | | This change incorporates recommendations from ET N-00-138, Rev. 0, by (a) clarifying Appendix R / fire protection compensatory measures, (b) clarifying fire brigade manning, and (c) clarifying Appendix R alternate shutdown equipment fire watch locations and their bases. | 7-19-01 |

**01-SE-OT-01**

**Description**
NAPS UFSAR, Section 9.6.4.1 & NAPS UFSAR Change Request No. FN 2000-044
Eliminate the requirement for prior SNSOC review and approval of all procedural changes to NUREG-0612 safe load paths or exclusion areas, as currently stated in NAPS UFSAR, Section 9.6.4.1.

**Summary**
NAPS UFSAR, Section 9.6.4.1, currently requires prior SNSOC review and approval of all deviations to NUREG-0612 safe load paths (also interpreted to include deviations to safe load path exclusion areas). The main issue associated with this Safety Evaluation is to determine whether this NAPS UFSAR statement is tied to any NUREG-0612 program commitment or can this current NAPS UFSAR requirement be deleted.

Virginia Power's original commitment to such procedure changes can be found in a December 15, 1982 letter to the US NRC (see Ref. 1). In that letter Virginia Power stated, "information concerning deviations to procedures with existing load paths...could be found in Section 5 of...[the] Quality Assurance Manual and in Section 6 of North Anna Power Station Technical Specifications." In other words, Virginia Power would follow the review process for such procedure changes, as set forth in our license bases, which at that time, required review by a station supervisory personnel with a follow-up review by SNSOC. In the Final NAPS TER, dated May 1984, Section 2.1.2.a, Summary of Licensee Statements and Conclusions (see Ref. 2), reiterated "Current plant procedures require that deviations to safe load paths be reviewed by station supervisory personnel with a follow-up review by the station nuclear safety and operating committee." Section 2.1.2.b, of the TER, stated the basis for acceptability as "Deviations from load paths are acceptably handled on the basis that prior approval is required and that the additional procedures and changes prepared receive at least two levels of supervisory review." The NRC's SER for Heavy Loads dated May 25, 1984 (see Ref. 3), has the simple conclusion "The staff has reviewed the TER and concurs with its findings that the guidelines in NUREG-0612, Sections 5.1.1 and 5.3 have been satisfied."

NAPS Technical Specifications, Section 6.8, denotes the requirements for SNSOC review of new and changed procedures. As stated in NAPS Plant Issue Evaluation Response N-2000-0389-E1 & R1, this section was recently revised by amendment 191/172. Currently, these NAPS Technical Specifications state that a procedure change requiring a Safety Evaluation is reviewed by SNSOC and a procedure change not requiring a Safety Evaluation is reviewed as discussed in the UFSAR. The NRC's SER for Amendment 191/172 noted that we stated "the screening process would be specified in [the] Operational Quality Assurance Program Topical Report and that procedure changes that do not require a safety evaluation must be approved by cognizant management and a senior reactor operator. Based on the screening process and procedure change approval by cognizant management and a senior reactor operator, the staff finds the proposed change ... acceptable." The QA Topical Report is now controlled as Chapter 17 of the UFSAR. Section 17.2.5, Instructions, Procedures, and Drawings, states the current process for review of procedure changes and requires cognizant management and SRO review, but does not require SNSOC review, of changes that do not require a safety evaluation. If a change has a safety evaluation, SNSOC review is required.

In conclusion, the original licensing basis has been properly modified (TS Amendment 191/172) and the current licensing basis for review of procedure changes to safe load paths for North Anna is based upon the NAPS Technical Specification requirement that the change receive SNSOC approval when the change is screened to require a safety evaluation. Therefore, the cited NAPS UFSAR, Section 9.6.4.1 statement, listed above, requiring prior SNSOC review and approval of all deviations to NUREG-0612 safe load paths, is not a program commitment and can be deleted. All procedure change review and approvals currently meet the commitments, as described in NAPS Technical Specifications and the Topical Report (UFSAR Chapter 17). As such, no unreviewed safety questions exist.

**01-SE-OT-02**

**Description**
UFSAR Change Request FN 2001-001
In response to Plant Issue N-2000-0636-R2, Engineering Transmittal CME 00-0047 has identified changes to Table 3C-2, High-Energy Lines (Outside Containment), Chapter 3 of the UFSAR are required. These changes are to the information provided in that table and will have no adverse affect on the evaluation for high energy line breaks documented in Appendix 3C of the UFSAR.

**Summary**
This safety evaluation addresses the changes to Table 3C-2, Appendix 3C of the UFSAR. The changes made provide corrections to the table as a result of the review conducted and documented in Engineering Transmittal CME-00-0047. Plant Issue N-2000-0636-R2 identified discrepancies between values listed in Table 3C-2, Appendix 3C of the UFSAR and the Line Designation Table listed in a parameter set of EDS. The discrepancies were the operating pressure and temperature, line size, seismic class, and quality class with the operating pressure and temperature data encompassing the bulk of the discrepancies. Review of the controlling documents in which Table 3C-2 and the Line Designation Table database provided the definitions by which each document bases its data on. Section 3C.2.2.1 of that Appendix defines operating temperature and pressure, "as the maximum temperature and pressure in the piping system, during occurrences that are expected frequently in the course of power operation, start-up, shutdown, standby, refueling, or maintenance of the plant." The EDS parameter set for the Line Designation Table provides fields for the "normal" pressure and temperature for each line contained within the table. The controlling document for the Line Designation Table is found in Mechanical Engineering Nuclear Standard STD-MEN-0022, Piping Line Designation Tables. Mechanical Engineering Nuclear Standard STD-MEN-0022 provides the definition of the "normal" pressure and temperature fields listed in the EDS database as such, "The normal pressure and temperature will correspond to the values encountered during normal operation of the system." The difference in the definitions could account for the differences in the published values in each document. Whereas the Appendix 3C is using maximum operating values to determine the type of high energy line break analysis, the Line Designation Table in EDS is listing conditions during steady state normal operating conditions in the plant, not start-up, standby, etc. conditions that may yield higher or lower pressure and/or temperature conditions. Regardless all changes to Table 3C-2 are bounded by the existing high-energy line break analysis for the lines addressed herein. Therefore changes required in the data appearing in Table 3C-2 of the UFSAR will be made.

In regard to line size, seismic class, pipe break evaluation type, and quality class discrepancies that were few in number, a definite source or cause of the discrepancies proved difficult to identify. It appears that the discrepancies are a result of typographical errors, errors in electronic data transfers, or failure to update a data base/document as a result of a design change or maintenance activity. To state a definite cause for each would be speculation. However, most of the minor discrepancies have been corrected with the issuance of Revision 36 of the UFSAR with the balance corrected by the review performed and documented in Engineering Transmittal CME-00-0047.

The change in Table 3C-2 of the North Anna UFSAR does not affect the operation of any plant system. The changes addressed and evaluated by this safety evaluation are used to determine if the affected lines are still bounded by their high-energy line break evaluations. It has been determined that there is no affect to the evaluations. There is no physical change to any plant system that would increase the probability or possibility of an accident or component malfunction previously analyzed, nor will it increase the probability or possibility of an accident or component malfunction of a different type. The evaluation performed to determine the effects of a high energy line break outside of containment and documented in Appendix 3C, Table 3C-2 remains valid and is not affected by the changes evaluated in engineering transmittal CME-00-0047. It can therefore be concluded that the changes to Table 3C-2 do not involve an unreviewed safety question.

**01-SE-OT-03**

**Description**
Technical Report, NE-1266, Revision 0, "Reload Safety Evaluation, North Anna 2 Cycle 15 Pattern OX," T. R. Flowers, February 2001.
UFSAR Change Request FN-2001-004.
Refueling and operation of North Anna Unit 2 Cycle 15 Pattern OX.
Incorporation of the following features described in Technical Report NE-1266, Revision 0:

1. Use of short (127.2") poison stack BP rods as in Cycle 14.

2. Twenty-eight of the peripheral assemblies will have replacement top nozzles.

3. Effects of a potential change in the RCS coolant chemistry program on safety.

4. A minor change in the fabrication of the top nozzle adapter plate, the use of cast top nozzles, and bead blasted Alloy 718 hold-down spring screws for the fresh fuel. Prior to this reload, Chapter 4, Section 2, Mechanical Design, of the UFSAR must be revised in order to incorporate the changes in the material of the hold-down spring screws that attach the springs to the top nozzle. These changes are included in UFSAR Change Request Number FN-2001-004. The basis for this change is Technical Report NE-1266, Revision 0. The UFSAR change does not affect any of the Safety Analyses contained in Technical Report NE-1266.

**Summary**
A safety evaluation has been performed to determine whether an unreviewed safety question will result from the refueling and operation of North Anna Unit 2 Cycle 15. In this evaluation, reload cycle parameters have been calculated and compared to the existing safety analysis assumptions. These parameters have been shown to be either explicitly bounded or accommodated by existing safety analysis margin and/or conservatism.

The impact of the following features and assumptions have been accounted for in the appropriate evaluations performed for N2C15:

1. Cycle 15 burnup limit is 20,900 MWD/MTU for EOC14 = 19,000 MWD/MTU, or 20,400 MWD/MTU for EOC14 = 19,900 MWD/MTU. These limits include up to a 5 °F Tavg coastdown at full power, followed by a customary power coastdown for a total coastdown of approximately 2500 MWD/MTU, past the end of normal Tavg full power reactivity. Tavg coastdown operation was approved for both North Anna units by NAPS Safety Evaluation No. 99-SE-OT-26, Revision 1, 08/05/99; and has already been implemented in N2C14 (Safety Evaluation No. 99-SE-OT-45, 9/23/99). The maximum Tavg reduction is limited to the value specified in the cycle-specific reload safety evaluation. N2C15 is limited to a 5 °F coastdown (NE-1266, Revision 0).

2. An RCCA fully withdrawn position of 226 steps.

3. Use of short (127.2") poison stack BP rods as in Cycle 14.

4. Twenty-eight of the peripheral assemblies will have replacement top nozzles.

5. A maximum FQ of 2.19 during normal operation, but reduced to 2.15 for the EOC Tavg and power coastdown, modified by K(z), as presented in Appendix A of Technical Report NE-1266.

6. Effects of a potential change in the RCS coolant chemistry program on safety.

7. A minor change in the fabrication of the top nozzle adapter plate, the use of cast top nozzles, and bead blasted Alloy 718 hold-down spring screws for the fresh fuel. Prior to this reload, Chapter 4, Section 2, Mechanical Design, of the UFSAR must be revised in order to incorporate the changes in the material of the hold-down spring screws that attach the springs to the top nozzle. These changes are

included in UFSAR Change Request Number FN-2001-004. The basis for this change is Technical Report NE-1266, Revision 0. The UFSAR change does not affect any of the Safety Analyses contained in Technical Report NE-1266.

One of the reload parameters was found to be outside the range of the generic safety analysis input assumptions, and therefore required specific evaluation. In accordance with the Topical Report VEP-FRD-42, Rev. 1-A, "Reload Nuclear Design Methodology," an evaluation was performed to determine the impact of the parameter on the currently applicable safety analyses, as described below.

The reload cycle fuel rod FΔH census is not bounded by the reference limit for all values. Based on the known DNBR sensitivity to FΔH in a thermal hydraulic evaluation (Reference 3), a penalty has been assessed against retained DNBR margin to accommodate the unbounded values in the census.

The results of this evaluation can be summarized as follows:

1. No increase in the probability of occurrence or consequences of an accident will result from this core reload. The reload creates only incremental changes in the values of parameters previously shown to be significant in determining core response to known accidents. Since the currently applicable safety analyses remain bounding for North Anna Unit 2 Cycle 15, it is concluded that operation with the proposed reload core will neither increase the probability of occurrence nor the consequences of initiating events for any known accident.

2. It has been determined that the effect on system operation and accident response is fully described by the parameters evaluated. Therefore, operation of this core does not create the possibility of an accident of a different type than any previously evaluated in the Safety Analysis Report.

3. The margin of safety is not reduced. The effects of core parameter variations were accommodated within the conservatism of the assumptions used in the applicable safety analyses. These analyses have demonstrated that calculated results meet all design acceptance criteria as stated in the UFSAR.

**01-SE-OT-04**

**Description**

UFSAR Change Request FN 2000-042 for North Anna Power Station UFSAR Chapters 6.2 and 6.3
Technical Specification Change Request 385 (Containment Air Partial Pressure Operating Curve) affecting TS 3.6.1.4 with Figure 3.6-1, 4.6.2.2.1, and 4.8.1.1.2 (Table 4.8-1)
Change to North Anna Power Station Emergency Operating Procedures 1/2-ES-1.3, "Transfer to Cold Leg Recirculation"
Also, this safety evaluation addresses the containment response analysis effects from the design changes listed in Block #7 (Items 2, 3, 4 and 5). However, specific safety evaluations for those changes may be required in accordance with the nuclear design control program.
Implementation of the revised LOCA containment integrity analysis requires changes to the North Anna Technical Specifications, Sections 6.2 and 6.3 of the North Anna UFSAR, and emergency operating procedure 1/2-ES-1.3. Explicit containment integrity analyses were performed to incorporate several revised design inputs related to containment initial conditions and heat removal systems. The current licensing basis includes evaluations of the revised inputs. The new analysis incorporates all of the changes into the LOCTIC computer code calculations, providing a complete, more robust accident analysis.

The new safety analysis provides justification for the following changes to the North Anna Technical Specifications:

- Revise TS Figure 3.6-1, containment air partial pressure versus service water temperature operating curve.
- Revise the TS IRS delay time from 195 to 400 seconds in TS 4.6.2.2.1 and TS 4.8.1.1.2 (Table 4.8-1).
- Revise the TS IRS delay timer uncertainty from 9.75 sec to 5.0 sec in TS 4.6.2.2.1 and TS 4.8.1.1.2 (Table 4.8-1).
- Revise the TS ORS delay timer uncertainty from 21.0 sec to 5.0 sec in TS 4.6.2.2.1 and TS 4.8.1.1.2 (Table 4.8-1).

The containment design criteria are satisfied for operation with the revised TS containment air pressure operating curve and the revised RS delay time values. The intent of the UFSAR update is to revise the analysis assumptions and results in Sections 6.2 and 6.3 for the containment peak pressure, depressurization, LHSI and RS pump NPSH, and inadvertent QS actuation event analyses to be consistent with the new safety analysis documented in technical report NE-1257, Rev. 0 [Reference 1 in Item 18]. This safety evaluation does not evaluate the plant design changes listed in Item 7 except as they relate to the containment response analysis. Rather, this evaluation supports the use of revised analysis assumptions that are based on the Item 7 plant changes. Separate safety evaluations will be performed for the plant design modifications described in Item 7. This safety evaluation only implements the revised safety analysis and the assumptions thereof.

**Summary**

**<u>Description of Change</u>**

This safety evaluation is performed for the implementation of a revised containment integrity analysis for North Anna Units 1 and 2. The analysis includes LOCA containment integrity and safeguards pumps NPSH analyses with the Stone & Webster Engineering Corporation (SWEC) LOCTIC computer code, which is also the basis for the existing licensing basis containment integrity analyses. The main steam line break containment integrity analysis was also evaluated. The containment response to the design basis LOCA was analyzed with revised design inputs to address findings from internal design basis review teams and items from industry and internal operating experience. One of the more significant changes is the incorporation of instrumentation uncertainty in areas of the analysis where nominal response had previously been assumed. Some plant instrumentation changes must be made in order to reduce uncertainties to acceptable values. The plant changes are identified in Item 7. The new containment analysis basis is documented in technical report NE-1257, Rev. 0 [Reference 1]. LOCTIC analyses were documented by SWEC in References 2-5.

The list of revised design inputs includes: uncertainties for refueling water storage tank (RWST) temperature, service water (SW) temperature, casing cooling temperature, containment air partial pressure,

and containment bulk temperature; revised flow rates for quench spray (QS), inside recirculation spray (IRS), outside recirculation spray (ORS), QS bleed, and SW; RS heat exchanger (RSHX) tube plugging and fouling; QS nozzle efficiency; RS and QS start times; RWST level for low head safety injection (LHSI) recirculation mode transfer (RMT); and accumulator discharge pressure. Significant design input changes were evaluated and included in the analysis basis as they were found. The main objective of the reanalysis was to explicitly include all revised design inputs in the LOCTIC simulations.

**Technical Specification Change 385**

A revised Technical Specification (TS) Figure 3.6-1 containment air partial pressure versus SW temperature operating domain was developed such that operation in the acceptable domain ensures that the containment design criteria are satisfied. The IRS delay timer setpoint and the IRS and ORS timer uncertainties were revised in the analysis such that new values must be incorporated into TS 4.6.2.2.1 and 4.8.1.1.2 (Table 4.8-1). The TS changes do not involve any changes to plant systems, structures, and components. The change to Figure 3.6-1 is a minor shift in the allowable containment air pressure operating domain but does not represent a change in operating philosophy. Analysis results with the proposed TS changes meet the applicable acceptance criteria. Specifically,

- The maximum containment pressure is less than the 44.1 psig containment leakrate pressure limit (TS 3.6.1.2 and 3.6.1.3), and the peak containment temperature is less than the design limit of 280°F.
- The containment depressurizes to less than 14.7 psia in less than 1 hour and remains subatmospheric thereafter.
- The LHSI and RS pumps have adequate NPSH to ensure pump integrity during the postulated LOCA.
- The containment liner design criteria are satisfied based on analysis of the inadvertent QS actuation event.
- The environmental zone description equipment qualification profiles for pressure and temperature are not exceeded during the postulated accident.

**UFSAR Change Request FN 2000-042**

Chapters 6.2 "Containment Systems" and 6.3 "Emergency Core Cooling System" of the North Anna UFSAR include extensive discussion of the containment design, system operating requirements, and analyses to ensure containment integrity and adequate NPSH for the safeguards pumps. The new safety analysis affects several sections in those chapters. This safety evaluation supports the changes included in UFSAR Change Request FN 2000-042.

A. Emergency Operating Procedure 1/2-ES-1.3

The safety analysis assumption for the RWST level at which LHSI recirculation mode transfer (RMT) occurs was changed from 23% to 20%. To accommodate the setpoint change, emergency operating procedure 1/2-ES-1.3 "Transfer to Cold Leg Recirculation" [Reference 7] will be modified to hold manual operator RMT actions until the automatic RMT setpoint of 20% RWST level is reached. This procedure change ensures that manual RMT could not be completed before reaching the safety analysis limit. As a result, the auto setpoint will initiate RMT, and the operator will verify the actions and perform manual backup, if necessary. The EOP change is required to ensure the plant procedures are consistent with the new analysis basis.

Item #7 lists the plant design changes that are required to support the implementation of the revised containment analysis. The design changes may require separate safety evaluations to support each change, because this safety evaluation only supports the use of analysis assumptions based on the plant changes in Item #7 as they affect the containment response analysis. The design changes are consistent with the revised safety analysis will not change the conclusions from the unreviewed safety question determination that follows.

It is expected that the RTDs located inside containment will be replaced during an outage. The TS change submittal will request that operation under the revised TS containment air pressure operating curve begin during the next outage sufficiently after NRC approval, rather than the normal implementation window.

**Unreviewed Safety Question Determination**

The results of this evaluation can be summarized as follows:

- No increase in the probability of occurrence of an accident or malfunction will result from the changes to the Technical Specifications, UFSAR, and EOPs. The probability remains unaffected since the accident analyses involve no change to a system, component, or structure that affects initiating events for any of the accidents evaluated. The analyses meet the applicable acceptance criteria (peak containment pressure less than 44.1 psig, containment pressure is subatmospheric within 1 hour and remains subatmospheric thereafter, available NPSH is greater than required NPSH for RS and LHSI pumps, the minimum containment pressure from an inadvertent QS event is greater than the containment liner design pressure, and the equipment qualification envelopes are not exceeded) for operation in the acceptable domain shown on revised TS Figure 3.6-1 for containment air partial pressure versus service water temperature. Since the containment design criteria are satisfied, radiological consequences of accidents previously evaluated in the North Anna Units 1 and 2 UFSAR will not be increased.

- The implementation of the proposed changes does not create the possibility of an accident of a different type than was previously evaluated in the SAR. The proposed Technical Specification, UFSAR, and EOP changes do not alter the nature of events postulated in the UFSAR nor do they introduce any unique precursor mechanisms. Therefore, there is no possibility for accidents of a different type than previously evaluated.

- The implementation of the proposed changes does not reduce the margin of safety. The containment analysis results satisfy the applicable acceptance criteria for operation within the acceptable operating limits of revised Technical Specification Figure 3.6-1 "Containment Air Partial Pressure Versus Service Water Temperature" and with the TS changes to the RS delay timer values. The change to EOP 1/2-ES-1.3 ensures adequate safety margin for the NPSH analyses. It is concluded that the margin of safety will not be reduced by the implementation of the changes to the Technical Specifications, UFSAR, and EOPs.

**01-SE-OT-05**

**Description**
ET CEE 00-0009, Rev. 0, **Defeating the RSST Load Shed Circuit with Both Units On-Line**
ET NAF 2001-0023, Rev. 0, **PRA Evaluation of Defeating RSST Load Shed Circuit with Both Units On-Line**
0-OP-26.7, Rev. 7, P1, **Reserve Station Service Load Shed**
UFSAR Change Request No. FN 2000-046

0-OP-26.7 will be revised to permit defeating the circuit for a period of up to 72 hours during operation of both Units 1 and 2. The UFSAR, section 8.3.1.1, will be revised to reflect the fact that the circuit can be defeated for maintenance activities.

**Summary**
Currently, there are no provisions to defeat the RSST load shed to allow any maintenance activities during those times when the load shedding must be enabled. In some cases, it is desirable to defeat the load shed circuit when both units are on-line. This change will allow the RSST load shed circuit to be defeated for up to 72 hours with both units on-line in order to allow maintenance to be performed. Due to the already low likelihood of two-unit loading of the RSST's (e.g., simultaneously two units trip and transfer and the generator breaker on Unit 1 fails to operate), defeating the RSST load shed circuit for a short period of time is acceptable. The 72 hour limit is an administrative limit. The Safety Monitor model will be modified to include this evolution and will be used to determine the acceptability of defeating the load shed when necessary.

The RSST load-shedding scheme will initiate whenever both the Unit 1 **and** Unit 2 Station Service Buses are fed from the associated Reserve Station Service transformer. The load shedding is also dependent on two control switches and the operating status of the associated Main Feedwater Pump motors. The load-shedding of certain non-safety-related secondary plant electrically driven equipment is intended to alleviate potential low-voltage profile conditions on the Reserve Station Service system during combined unit operation using only the Reserve Station Service transformers.

Before and during start-up of Unit 2, Station Service Buses 2A, 2B, and 2C are supplied from Reserve Station Service transformers A, B, and C, respectively. After the Unit 2 generator is on-line, the Station Service Buses are transferred to the Station Service transformers. For several events, principally a Unit 2 trip, the buses will be automatically transferred to the associated Reserve Station Service transformers.

Unit 1 Station Service buses 1A, 1B, and 1C are normally supplied from the Station Service transformers at all times. The 22kV main generator breaker eliminates the need to routinely supply the buses from the Reserve Station Service transformer. For several events, principally equipment failures, the Unit 1 Station Service buses will automatically transfer to the associated Reserve Station Service transformers, similar to Unit 2. However, the installation of the Unit 1 main generator breaker greatly reduces the likelihood of combined loading from both Units 1 and 2 Station Service Buses on the Reserve Station Service transformers.

In the event of two-unit loading of the RSST's with the load shed circuit defeated, the higher load would result in lower voltage. The RSST's would be overloaded and it is probable that one or more Emergency Buses would separate from the offsite power supplies via the undervoltage relays and transfer to the Emergency Diesel Generators. While the EDG's are capable of supplying the loads under any condition, this event would be very undesirable and is in direct conflict with the goals of GDC-17. If both units are operating in a normal configuration, some type of failure would be required on Unit 1 to initiate transfer of the station service loads to the RSST's in conjunction with the transfer of the Unit 2 loads.

**The probability or consequences of an accident or malfunction previously evaluated in the safety analysis report are not increased.**
The Electrical Distribution System is fully operable and the performance characteristics of safety related systems are unaltered. The RSST load shed circuit will be defeated during maintenance activities to preclude inadvertent actuation, which could result in the loss of normal feedwater and a turbine trip. This change does not increase the probability of a turbine trip, loss of normal feedwater, or a loss of offsite power to the station auxiliaries. Defeating the RSST load shed circuit does not impact the consequences of an accident. The load shed circuit alleviates potential low-voltage profile conditions on the reserve station

service system during combined unit operation using only the reserve station service transformers. For the load shed circuit to operate, both units must trip and a failure must occur to initiate transfer of the Unit 1 station service loads to the RSST's. (Normally, the main generator breaker operates and Unit 1 buses do not transfer.) The defeat of the load shed will be procedurally controlled to minimize the likelihood of combined unit loading on the RSST's. Therefore, the probability of loss of offsite power to the emergency bus(es) is not increased. The consequences of a loss of offsite power to the emergency buses are unchanged. The EDG's are fully capable of supplying the necessary loads to maintain the plant in a safe condition or to mitigate the consequences of an accident.

**The possibility of an accident or malfunction of a different type than previously evaluated in the safety analysis report is not created.**

No new accident precursors are introduced. Two unit loading of the RSST's with no load shedding could result in low voltage and separation of the emergency bus(es) from offsite power. This would require that the buses be supplied from the EDG's. While this is undesirable, a total loss of offsite power has been previously evaluated in the SAR. Defeating of the RSST load shed circuit will be procedurally controlled to minimize the likelihood of this event. This change will allow use of a control switch to defeat the load shed circuit. This does not create the possibility for a malfunction of equipment of a different type than was previously evaluated in the SAR. The changes do not affect the outcome of the accident analyses.

**The margin of safety as defined in the basis for any Technical Specification is not reduced.**

The emergency power system capability to power the safe shutdown and accident mitigation equipment is not affected. The operation of other systems is unaffected. No safety limits or limiting safety system settings are altered. Therefore, the margin of safety has not been reduced.

**01-SE-OT-07**

**Description**
Plant Issue Number N-2000-2489-R2
UFSAR Change Request FN 2000-047
Startup of an Inactive Loop Accident Analysis Design Basis Document (AADBD) update tracked by NAF Level I tem 1272. Technical Report NE-1200, "Key Operator Actions Assumed in Safety Analyses", Update tracked by NAF Level I Item 1274.
The proposed UFSAR changes update Section 15.2.6, "Startup of an Inactive Loop", to reflect the current design bases that credit Technical Specification controls to preclude the preconditions for significant and uncontrolled reactivity insertion during the startup of an inactive loop (i.e., reduced boron concentration or temperature in an isolated loop). A conservative analysis of the reactivity effects of the isolated loop recirculation activity required by Technical Specification 3.4.1.5.a is also being incorporated into Section 15.2.6.

**Summary**
**Purpose**

The purpose of the Safety Evaluation is to implement a revised discussion of the Startup of an Inactive Loop accident analysis into North Anna UFSAR Section 15.2.6. The existing UFSAR discussion of the Startup of an Inactive Loop (SUIL) accident analysis in UFSAR Section 15.2.6 does not accurately reflect the current NRC-approved licensing position. In addition, the existing UFSAR discussion does not present an analysis of the reactivity effects of the isolated loop recirculation activity required by Technical Specification 3.4.1.5.a. The proposed UFSAR changes modify UFSAR Section 15.2.6 to correct these deficiencies. The technical bases for the proposed UFSAR changes are documented in Calculation SM-1275, "Startup of an Inactive Loop Accident Analysis for North Anna Units 1 and 2," dated February 2001 (1).

**Background**

As of this writing, UFSAR Section 15.2.6.2.1.2 (ICMP Database Record 31089) states the following:

*The start-up of an inactive reactor coolant loop with the loop stop valves initially closed has been analyzed assuming the inactive loop to be at a boron concentration of 0 ppm while the active portion of the system is at 1200 ppm, a conservatively high value for the required shutdown margin for beginning of life. The flow through the relief line is assumed at its maximum value of 330 gpm.*

The conclusions regarding the analysis of this scenario of the startup of an inactive loop accident are documented in Section 15.2.6.2.2.2 (ICMP Database Records 31094 and 52722):

*15.2.6.2.2.2 Loop Stop Valves Closed. Even with the assumption that administrative procedures are violated to the extent that an attempt is made to open the loop stop valves with 0 ppm in the inactive loop while the remaining portion of the system is at 1200 ppm, the dilution of the boron in the core is slow. The initial reactivity insertion rate is calculated to be less than $2.6 \times 10^{-5}$ delta-k/sec, considerably less than the reactivity insertion rates considered in Section 15.2.2. For these conditions, the time required for the shutdown margin to be lost and the reactor to become critical is 16.4 minutes. This calculation takes into account the reduced reactor coolant system volume due to the isolated loop. This is ample time for the operator to recognize a high count rate signal and terminate the dilution by turning off the pump in the inactive loop or by borating to counteract the dilution.*

Nuclear Analysis and Fuel (NAF) / Reactor Engineering staff observed that the range of RCS boron concentrations considered in the UFSAR analysis (i.e., 0 ppm to 1200 ppm) do not conservatively bound the range of expected boron concentrations required to meet shutdown margin requirements at cold, no xenon (Xe), all rods in (ARI) conditions. Critical boron concentrations (cold, no Xe, ARI) in the range of 1300 ppm to 1400 ppm have been experienced in recent North Anna core designs. NAF staff investigated

this discrepancy and concluded that the analysis is conservative in terms of the *boron concentration difference* considered in the analysis relative to boron concentration differences that can realistically be achieved under the constraints of current Technical Specifications. NAF also concluded that the SUIL "Loop Stop Valves Closed" analysis presented in the UFSAR is historical in nature. Specifically, licensing actions subsequent to the incorporation of this analysis into the UFSAR have credited Technical Specification controls for precluding the pre-conditions necessary for the SUIL "Loop Stop Valves Closed" scenario to result in a significant and uncontrolled reactivity addition. A discussion of the licensing history for the Startup of an Inactive Loop accident analysis is presented below.

The original North Anna Units 1 and 2 Technical Specifications included requirements for un-isolation of isolated reactor coolant loops. The purpose of the requirements was to prevent inadvertent criticality during the process of bringing the loop into service, and to avoid reactor vessel thermal shock and the imposition of excessive thermal fatigue on vessel components, paticularly on the cold leg nozzles. The Technical Specifications required that the isolated loop remain closed unless (a) the isolated loop had been operated on a recirculation flow of greater than or equal to 125 gpm for at least 90 minutes, (b) the temperature of the cold leg of the isolated loop was within 20°F of the highest cold leg temperature of the operating loops, and (c) the reactor was subcritical by at least 1.77%$\Delta$k/k. As of this writing, these requirements still remain in effect. The recirculation activity required by Technical Specifications is performed under strict administrative control, and does not by itself constitute a boron dilution event. Nonetheless, UFSAR Section 15.2.6.2.1.2 evaluates the reactivity effects of inadvertent startup of an inactive loop with the loop stop valves closed. The most recent analysis performed for the North Anna Core Uprating effort (described below) assumes two loops are in operation and one loop is isolated (i.e., N-1 loop operation), even though this operating mode was eliminated by Technical Specification Amendment 32. (Letter from R. A. Clark to J. H. Ferguson, Serial No. 354 dated June 2, 1981. Additional information on licensing history is available in Letter from J. P. O'Hanlon to USNRC, "Virginia Electric and Power Company, North Anna Power Station Units 1 and 2, Proposed Technical Specifications Change, Revised Loop Stop Valve Operation," Serial No. 96-532, dated November 6, 1996.)

An analysis of the SUIL "Loop Stop Valves Closed" case was performed as part of the North Anna Core Uprating effort to determine the time required for complete loss of shutdown margin. (See Letter from W. L. Stewart to H. R. Denton (NRC), "Amendment to Operating Licenses NPF-4 and NPF-7, North Anna Power Station Unit Nos. 1 and 2, Proposed Technical Specification Changes," dated May 2, 1985.) Because N-1 loop operation is precluded by Technical Specifications, this analysis is historical in nature. However, the analysis does provide a technical basis (although an incomplete technical basis) for concluding that sufficient time exists for corrective operator action in response to boron dilution resulting from procedurally-controlled coolant recirculation with a loop stop valve closed. The Core Uprating analysis assumed that the coolant in the inactive loop contained 0 ppm boron, while the active portion of the system contained 1200 ppm boron. At the time of the analysis, this boron concentration was considered consistent with estimates of the boron concentration required to meet the minimum shutdown margin at Beginning-of-Life (BOL). Flow through the relief line was assumed to be at its maximum value of 330 gpm. The initial reactivity insertion rate was calculated to be less than 2.6E-5 $\Delta$k/sec, which is considerably less than the reactivity insertion rates considered in the Rod Withdrawal from Subcritical event analyses. For these conditions, the time required for the minimum Technical Specification shutdown margin to be lost, and the reactor to become critical was calculated to be 16.4 minutes. This was concluded to be ample time for the operator to recognize a high Source Range count rate signal and terminate the dilution by turning off the pump in the inactive loop, or by borating to couteract the dilution. The core uprating analysis further concluded that the reactivity addition at End-of-Life (EOL) is less limiting than that assumed above to occur at BOL.

By letter dated November 6, 1996 (Letter from J. P. O'Hanlon to USNRC, "Virginia Electric and Power Company, North Anna Power Station Units 1 and 2, Proposed Technical Specifications Change, Revised Loop Stop Valve Operation," Serial No. 96-532, dated November 6, 1996), Virginia Power requested amendments to the Technical Specification requirements for isolated loop startup to permit filling a drained and isolated loop via backfill from the RCS through partially opened loop stop valves. The Technical Specification change submittal included the technical basis for elimination of the loop stop valve interlocks based on temperature and relief line flow. (Note that the loop stop valve interlock requirements were not

governed by Technical Specifications.) However, the 20°F temperature difference and 90-minute recirculation flow requirements remained in the Technical Specifications. The basis for elimination of the loop temperature and recirculation flow portions of the loop stop valve interlocks was the establishment of procedural controls governed by Technical Specifications to preclude the possibility of inadvertent reactivity addition due to temperature reduction or boron dilution. The Technical Specifications and associated plant procedures include the following controls:

a. The boron concentration in the isolated loop is required to be maintained higher than the boron concentration in the operating loops, thus eliminating the potential for introducing coolant from the isolated loop that could dilute the boron concentration in the operating loops. (Note: this requirement has been modified to require a boron concentration in the isolated loop that is greater than that which satisfies the mode-dependent shutdown margin requirement as applicable for the active volume of the RCS. See Letter from S. R. Monarque (NRC) to D. A. Christian, "North Anna Power Station Units 1 and 2 – Issuance of Amendments Re: Technical Specification Change for Reactivity Controls – Return Isolated Reactor Coolant System Loops to Service," (Amendments 223 and 204), Serial No. 00-465, dated August 25, 2000.)
b. The reactor must be subcritical by at least 1.77% $\Delta k/k$ prior to opening a cold leg loop stop valve. This ensures that any minor reactivity changes associated with temperature gradients cannot result in inadvertent criticality.
c. Prior to opening a cold leg loop stop valve, the isolated loop must operate on a recirculation flow of greater than or equal to 125 gpm for at least 90 minutes. This ensures a slow, controlled mixing of the contents of the isolated and active loops.
d. The temperature of the cold leg of the isolated loop must be within 20°F of the highest cold leg temperature of the operating loops. This restriction limits the potential reactivity addition due to cooldown to a small amount that is readily accommodated by the available shutdown margin.

The November 6, 1996 submittal was followed by responses to various NRC Requests for Additional Information (RAIs). (See Letter from N. Kalyanam to J. P. O'Hanlon, "Request for Additional Information – Revised Loop Stop Valve Operation; North Anna Power Station Units 1 and 2," Serial No. 98-179, dated March 16, 1998. See also Letter from J. P. O'Hanlon to USNRC, "Virginia Electric and Power Company, North Anna Power Station Units 1 and 2, Proposed Technical Specifications Change, Revised Loop Stop Valve Operation," Serial No. 98-179, dated April 15, 1998. See also Letter from N. Kalyanam to J. P. O'Hanlon, "Request for Additional Information – Revised Loop Stop Valve Operation; North Anna Power Station, Units 1 and 2," Serial No. 98-364, dated June 9, 1998.) Of particular interest is the letter dated April 15, 1998, in which Virginia Power responded to an NRC inquiry concerning the erosion of shutdown margin due to the introduction of coolant with reduced temperature but with adequate boron concentration. The analysis considered introduction of 32°F water into a core operating at 200°F with no mixing between the cold loop and the other loops. The analysis demonstrated that the net reactivity addition was less than one half of the minimum shutdown margin required by Technical Specifications. Thus, neither the inadvertent opening of a loop stop valve nor the loop stop valve bypass line recirculation activity required by Technical Specifications presents any concerns relative to loss of shutdown margin under conditions of reduced isolated loop temperature. Approval of the November 6, 1995 submittal, and the associated RAI responses, was granted by Letter from N. Kalyanam to J. P. O'Hanlon, "North Anna Power Station, Units 1 and 2 – Issuance of Amendments – Startup of Isolated Loop by Backfill," dated October 30, 1998.

By letters dated June 22, 2000 (Letter from D. A. Christian to USNRC, "Virginia Electric and Power Company, North Anna Power Station Units 1 and 2, Proposed Technical Specification Changes, Response to Request for Additional Information," Serial No. 00-304, dated June 22, 2000) and July 25, 2000 (Letter from D. A. Christian to USNRC, "Virginia Electric and Power Company, North Anna Power Station Units 1 and 2, Corrected Pages for Proposed Technical Specification Changes, Reactivity Controls – Return of Isolated RCS Loops to Service," Serial No. 00-304A, dated July 25, 2000), Virginia Power requested Technical Specification changes to accommodate the vacuum-assisted fill technique for returning isolated RCS loops to service. In addition to providing additional Technical Specification requirements to support the vacuum-assisted loop backfill technique, these submittals affirmed the continued applicability of the

Technical Specification controls that preclude the possibility of inadvertent reactivity addition during or following loop stop valve operations. The NRC Safety Evaluation Report for these submittals is documented in a Letter from S. R. Monarque to D. A. Christian, "North Anna Power Station Units 1 and 2 – Issuance of Amendments Re: Technical Specification Change for Reactivity Controls – Return Isolated Reactor Coolant System Loops to Service," Serial No. 00-465, dated August 25, 2000. In the SER, the NRC states "The licensee's proposed TS changes provide necessary controls to ensure that the preconditions related to reactivity for the startup of an inactive RCS loop accident are precluded."

By eliminating the possibility of the pre-conditions necessary for a significant and uncontrolled reactivity addition during the startup of an inactive loop, the accident analysis presented in UFSAR Section 15.2.6.2.1.2 is no longer relevant to the North Anna design basis, and is considered "historical" in nature. Because of the Technical Specification controls described above, the only relevant analysis that might be performed for the Startup of an Inactive Loop accident is an evaluation of the operational impact of performing the recirculation activity required by Technical Specifications in the presence of a hypothetical reduced boron concentration in the isolated loop. An evaluation of this type is presented Calculation SM-1275 (1).

**Basis for UFSAR Update**

Nuclear Analysis and Fuel has performed an analysis of the SUIL "Loop Stop Valves Closed" case assuming that three RCS loops are isolated and RHR is in operation when the recirculation activity required by Technical Specification 3.4.1.5.a is initiated. As a result of this configuration, the volume of the active portion of the reactor coolant system is reduced to 3345 $ft^3$. The analysis assumes an initial RCS boron concentration of 1800 ppm. This boron concentration conservatively bounds the predicted boron concentration required to meet the Technical Specification minimum shutdown margin requirement of 1770 pcm at Cold Zero Power (CZP), Beginning of Cycle (BOC), All Rods In (ARI), No Xenon (Xe) conditions. The isolated loop boron concentration was assumed to be 1300 ppm, 500 ppm less than the 1800 ppm concentration assumed to exist initially in the active portion of the RCS. The concentration difference is conservative, given that the Technical Specifications governing restoration of isolated and drained loops to service ensure that the boron concentration in the isolated loop will be greater than or equal to the boron concentration corresponding to the mode-dependent shutdown margin requirement (e.g., 1800 ppm). The design maximum loop stop valve bypass line flow rate of 330 gpm was assumed to be transferred to the reduced RCS volume. The analysis assumes a differential boron worth that conservatively bounds values expected to occur over core life.

These conditions were analyzed with a "perfect mixing" model as well as a "dilution front" model. In the "perfect mixing" model, the inventory transferred from the isolated loop during each time step was assumed to be instantaneously distributed throughout the active portion of the reactor coolant system. Likewise, the inventory transferred from the active portion of the reactor coolant system during each time step was assumed to be instantaneously distributed throughout the isolated loop. The "dilution front" model assumes that, because of the relative flow rates, the inventory transferred from the isolated loop causes a diluted slug of water to pass through the reactor core. With each loop transit, the boron concentration of the slug of water "steps down" to a value calculated as a weighted average based on the dilution flow rate and boron concentration and the RHR flow rate and the boron concentration of coolant in the active portion of the RCS.

The Nuclear Analysis and Fuel calculation determined that between 17.0 minutes ("dilution front" model) and 50.5 minutes ("perfect mixing" model) are available for corrective operator action in response to increasing source range neutron count rate. The estimated reactivity insertion rates during the transient are well within the range of reactivity insertion rates considered in the Rod Withdrawal from Subcritical accident analysis. The NRC staff criteria for boron dilution events set forth in Standard Review Plan Section 15.4.6 require 15 minutes to be available for corrective operator action between the time an alarm makes the operator aware of unplanned moderator dilution and complete loss of shutdown margin (2). Because the recirculation activity is a controlled and monitored evolution, 17.0 minutes is sufficient time for operators to identify a dilution in progress and to terminate the evolution.

## Unreviewed Safety Question Determination

The proposed revised UFSAR discussion of the Startup of an Inactive Loop accident analysis documented in UFSAR Change Request FN 2000-047 does not create the possibility of a new or different kind of accident, increase the probability of occurrence or consequences of accidents previously analyzed, nor decrease any margin of safety inherent in previously performed accident analyses. Technical Specification controls described in North Anna TS 3.4.1.5 and 3.4.1.6 preclude the possibility of a significant and uncontrolled reactivity addition during the startup of an inactive loop. The loop stop valve bypass line recirculation activity required by TS 3.4.1.5.a is a procedurally controlled evolution, and does not itself constitute a boron dilution event. A conservative analysis of this event demonstrates that there is adequate time for corrective operator action in response to credible scenarios of reactivity insertion due to reduced boron concentration or temperature. No new operating modes or allowable plant conditions are being introduced by the proposed UFSAR changes that could create the possibility of a new or different type of accident, or which could increase the probability of occurrence or consequences of accidents previously analyzed.

(1) Calculation SM-1275, "Startup of an Inactive Loop Accident Analysis for North Anna Units 1 and 2," dated February 2001.

(2) Letter from W. J. Chipiwalt (VEPCO) to B. C. Rusche, "Amendment No. 44", Serial No. 827, dated December 29, 1975 (citing requirements of Standard Review Plan, NUREG-0800, Section 15.4.6, April 1975 as applicable to the North Anna Power Station license application).

**01-SE-OT-09**

**Description**
SAR Change Request FN-2000-049, SW Spray Array Clarification,
O-PT-75.11 and OP-49.1
VP. Calculation ME-062 and addendum determines the minimum number of spray arrays needed to support design basis requirements. The UFSAR will be clarified (revised) and changed to indicate the minimum number of spray arrays required to be operable to meet design basis minimum requirements. Evaluation indicates that three spray arrays out of eight are required to meet the design basis requirements of the NAPS Service Water Spray Array System with two SW headers operable following a single failure. To meet minimum design basis requirements whether with a single SW header in operation or both SW headers operating, no less than three spray arrays must always be operable including any single failure considerations that may be appropriate.

**Summary**
Since this UFSAR change reflects only a clarification to existing design basis information in the UFSAR no Unreviewed Safety Question exists for this safety evaluation. A UFSAR change has been requested by station personnel to clarify the design basis minimum number of spray arrays needed to support the plant design basis. During repairs to a NAPS SW spray array in May 1998, initial engineering reviews were performed which indicated that one of four spray arrays on each SW header could be removed from service without affecting operability of the SW header. Additionally, a UFSAR change request is warranted since the design basis calculation ME-062 states that only 3 of 4 arrays are required for a header to be operable (minimum safeguards). Whereas the UFSAR states that 4 arrays (2 pairs) are required for DBA mitigation (1 pair per header or two pair on a single header). This apparent discrepancy generated a plant deviation report (DR 98-1750). The following paragraphs provide the required clarifications to the UFSAR.

The LOOP and LOCA are the design basis accidents previously considered and are not effected by the clarifications to the UFSAR as a result of this UFSAR Change request. Clarification of the UFSAR does not increase the probability of occurrence for any accident considered. Since the accidents previously considered are not affected, by this clarification of the UFSAR no consequences of a previously considered accident are increased. Clarifications to the UFSAR will not result in the possibility for an accident of a different type than was previously considered.

Equipment failure such as the spray array valves and headers and supporting equipment, which have been previously considered, have been considered for this Safety Evaluation. The clarifications to the UFSAR to do not increase the probability of occurrence of malfunctions previously identified. No malfunctions of a different type are suggested by the new clarifications added to the UFSAR by this UFSAR Change Request.

The clarifications to the UFSAR that increase the understanding of the functionality of the Spray Array system have not been addressed in the Technical Specification bases section. Therefore, no reduction in any margin of safety results from these clarifications to the UFSAR.

The proposed change does not require a change to the Operating License or Technical Specifications since they are editorial in nature and only provide clarifications to the design basis requirements of the Service Water Spray array system.

The following will be added to the UFSAR as a clarification of the minimum design basis of the Service Water Spray array system:

"Under the most limiting conditions, a single SW supply and return header will meet the SW system accident design basis requirements of a simultaneous loss-of-coolant-accident (LOCA) for one unit and loss of offsite power for both units. Assuming the most limiting single failure, the minimum design basis requirements for the SW system reservoir spray array are met with either one or both SW headers in

operation as long as a minimum of three spray arrays remain OPERABLE following the failure. Three out of four spray arrays are required with only one SW header (supply and return) in operation or three out of eight spray arrays with both SW return headers in operation.

A failure in the SSPS system of a master relay or the slave relay (K608) can result in the failure of four spray isolations MOV's to automatically open, if initially closed. If two spray array isolation MOV's are closed and inoperable prior to the event, potentially six spray arrays will fail to open during a design basis accident. Therefore, to ensure three spray arrays remain operable, only one spray array out of the eight total spray arrays may be closed and out of service. However, two spray arrays may be inoperable if they are on separate SI trains. If a spray array is inoperable solely due to the inability of its associated MOV to automatically open, the array may be considered operable if the MOV is administratively maintained in the open position."

**01-SE-OT-10**

**Description**

UFSAR Change Request FN 2001-010 for North Anna Power Station UFSAR Section 6.2.5.3

The change adds description to specify the bounds of applicability of the zinc material assumptions (relative to the actual plant configuration) in the North Anna containment hydrogen generation analysis in UFSAR Section 6.2.5.3. The current licensing basis analysis includes distinct inputs for zinc paint and zinc metal, but the hydrogen generation rate per unit of surface area is assumed to be the same for both zinc subcategories in the analysis of record. Materials/ISI Engineering reports in Reference 4 that the zinc metal in containment exceeds the analysis input while the zinc paint assumption is much greater than the zinc paint in containment. The evaluation concludes that it is important that only the total zinc mass and surface area be verified against the total assumed in the safety analysis, and that subcategory verification is not required. The UFSAR change clarifies the limits on zinc material in containment that are imposed by the safety analysis.

**Summary**

**Description of Change**

This safety evaluation is performed to add description regarding the bounds of applicability of the zinc material assumptions (relative to the plant configuration) in the containment hydrogen generation analysis in Section 6.2.5.3 of the North Anna UFSAR [1]. No reanalysis was performed. Rather, the description of material inputs is amended to clarify that the total zinc mass and surface area, not individual subcategories of zinc, are the parameters that must be verified against the containment inventory.

Currently, UFSAR Section 6.2.5.3 and Table 6.2-59 and the safety analysis [2] present the zinc inputs to the analysis in two subcategories: paint and galvanized metal. Materials/ISI Engineering verification of the containment inventory [3,4] concluded that there is more metal than the safety analysis input, while there is no or very little exposed zinc paint. ET NAF 2001-0025 [5] was written to evaluate the impact on the hydrogen generation analysis of the metal inventory being larger than the safety analysis input. Reference 2 concluded that the analysis of record hydrogen generation rate per unit of zinc surface area is the same for paint and metal (this conclusion was verified for Surry's Reference 6 analysis). Therefore, the analysis of record remains bounding because the total zinc mass and total exposed zinc surface area are less than the total assumed in the safety analysis. The UFSAR change adds this clarification to avoid future PI's after each inventory that documents more galvanized metal than the safety analysis assumption. ET NAF 2001-0025 establishes the total zinc mass and surface area limits for Materials/ISI Engineering to ensure that the containment hydrogen analysis continues to bound the plant configuration.

In conclusion, the maximum hydrogen concentration of 3.9% calculated in Reference 2 remains the analysis basis. This safety evaluation supports the changes included in UFSAR Change Request FN 2001-010.

The results of this evaluation can be summarized as follows:

- No increase in the probability of occurrence of an accident or malfunction will result from the changes to the UFSAR. The probability remains unaffected since the accident analysis is not revised. A brief description is added to the UFSAR to clarify the bounding nature of the zinc inputs in the containment hydrogen analysis. There is no change to a system, component, or structure that affects initiating events for any of the accidents evaluated in the SAR. The containment hydrogen generation analysis of record is not affected and continues to meet the applicable acceptance criteria. Since the containment design criteria are satisfied, radiological consequences of accidents previously evaluated in the North Anna Units 1 and 2 UFSAR will not be increased.

- The implementation of the proposed UFSAR changes does not create the possibility of an accident of a different type than was previously evaluated in the SAR. The proposed UFSAR changes do not alter the nature of events postulated in the UFSAR nor do they introduce any unique precursor mechanisms. Therefore, there is no possibility for accidents of a different type than previously evaluated.

- The implementation of the proposed UFSAR changes does not reduce the margin of safety. The containment hydrogen generation analysis results are not altered and the applicable acceptance criteria continue to be met. It is concluded that the margin of safety will not be reduced by the implementation of the UFSAR changes.

**01-SE-OT-11**

**Description**
UFSAR Change Request FN 2001-002

The UFSAR requires revision to support the replacement of Calgon biocide H-510 with Applied Specialties Inc. biocide AS-590 (copper-free) in the bearing cooling (BC) system. The generic chemical name, 'Isothiazolin', should be referenced in the UFSAR, VPAP, and the appropriate chemistry and operations procedures, rather than the vendor name. Isothiazolin is a common pesticide used for algae control in the BC system. The addition of copper-based chemicals in Calgon H-510 act only to promote the shelf life of the product. In order to facilitate continuous blowdown of the BC water to Lake Anna, we must use copper-free forms of Isothiazolin. Due to the relatively small volumes that are kept on site, shelf life is not a concern. By referencing only the basic active chemical biocide, rather than the vendor product name, the chemical can be purchased without the need for UFSAR or procedural changes.

Engineering calculation ME-0567, Rev. 1 corrected several mathematical errors, thus changing the maximum expected concentrations in the Control Room following a chemical spill. The affected chemicals include Hydrazine, Ethanolamine, and H-510 Biocide. The hazard levels associated with Zinc Chloride and Sodium Molybdate were also clarified. These two chemicals only pose a significant threat to humans when solid particles or fumes created by burning are inhaled. These changes to ME-0567, Rev. 1 require that the UFSAR be updated.

**Summary**
<u>Background</u>

PI N-2001-0397 required the revision of calculation ME-0567, Rev. 1 to correct several mathematical errors. These errors impact the maximum expected concentration in the control room following a chemical spill. Criterion 19 of 10CFR50, Appendix A, "Control Room," requires that the Control Room remain habitable during normal and accident conditions. As a result of the above changes, Engineering performed an evaluation to ensure Control Room habitability will be maintained following a chemical spill.

To support continuous BC blowdown during warm weather months, Calgon H-510 is being replaced with a copper-free form of Isothiazolin. This change was evaluated in ME-0567, Rev. 1. The maximum allowable concentration of Isothiazolin was determined to be 5.0%.

The evaluation considered the following areas for each chemical addressed:

- Quantity, toxicity, and state in the plant.
- Chemical transport into the MCR via the emergency air intakes.
- Worst-case concentration level in the MCR

Calculation ME-0567, Rev. 1 was initiated to determine if any chemicals pose a threat to Control Room habitability. The calculation showed that all chemicals would have a Control Room concentration less than their toxicity limit in the event of a spill. The evaluation concluded that no chemical stored on site in a quantity over 100 pounds could adversely affect Control Room personnel following a release.

<u>Major Issues Considered</u>

**Probability or Consequences of Malfunctions** – No modifications are being made to plant systems and their operation as a result of this change. The evaluated condition has no impact on events or mechanisms that could initiate the accidents listed in the SAR. There are also no physical changes to plant systems and components that perform accident mitigation functions. An accident of a different type is not created as a result of this document change or the change in the biocide used in the BC system.

**Technical Specification / Operating License** – The Technical Specification sections relevant to Control Room Habitability are:

- Plant Systems, Control Room Emergency Habitability System Section 3.7.7.1, LCO and 4.7.7.1, Surveillance Requirements
- Plant Systems, Bases, Control Room Emergency Habitability System Sections 3/4.7.7

The Technical Specifications are not affected in any way by this change. The Mechanical Engineering evaluation and corresponding UFSAR changes document the safety of Control Room habitability with the on-site chemical storage configuration per VPAP 2202.

**Safe Shutdown Capability** – The SE and corresponding UFSAR changes are performed to ensure the safety of the plant based on an updated evaluation of the on-site chemical storage configuration. In addition, the storage of the biocide does not alter the operation of any system, component or structure as defined in the UFSAR. Because there are no physical modifications to the plant operating systems and components associated with the changes, there is no impact on the station's ability to achieve and maintain safe shutdown in the event of a fire. In addition, operation from the Auxiliary Shutdown Panel will not be adversely affected.

The use of Isothiazolin in the concentrations commercially available does not present a fire hazard. Magnesium chloride and Magnesium Nitrate are chemical bi-products found in the biocides. Isothiazolin and the chemical bi-products contained in the commercially available biocides are non-volatile in the available concentrations.

**Environmental Impact** – Mechanical Engineering has determined the plant to be safe with respect to the current chemical storage configuration. In addition, the replacement of Calgon H-510 with Applied Specialties AS-590 or an equivalent biocide containing no more than 5% WT concentration Isothiazolin will not adversely affect the chemical storage configuration of the plant. Therefore, there will be no impact on the environment or the FES. Since no changes are being made to the plant operating systems or components, no changes in power level or effluents are expected. No change to the Environmental Protection Plan is required.

For these reasons, these changes to the UFSAR & ME-0567 (Rev. 1) do not create an unreviewed safety question.

**01-SE-OT-11 Rev 1**

**Description**

UFSAR Change Request FN 2001-002

The UFSAR requires revision to support the replacement of Calgon biocide H-510 with NALCO 2894 Algicide (copper-free) in the bearing cooling (BC) system. The generic chemical name, 'Isothiazolin', should be referenced in the UFSAR, VPAP, and the appropriate chemistry and operations procedures, rather than the vendor name, where appropriate. Isothiazolin is a common pesticide that has been used for algae control in the BC system. Copper-based chemicals in Calgon H-510 are added to promote the shelf life of the product, however the copper additives do increase the biocides effectiveness in controlling algae. In order to facilitate continuous blowdown of the BC water to Lake Anna, we must use copper-free forms of Isothiazolin. Due to the relatively small volumes that are kept on site, shelf life is not a concern. By referencing only the basic active chemical, rather than the vendor product name, the chemical can be purchased without the need for UFSAR or procedural changes.

Engineering calculation ME-0567, Rev. 1 corrected several mathematical errors, thus changing the maximum expected concentrations in the Control Room following a chemical spill. The affected chemicals include Hydrazine, Ethanolamine, and H-510 Biocide. The hazard levels associated with Zinc Chloride and Sodium Molybdate were also clarified. These two chemicals only pose a significant threat to humans when solid particles or fumes created by burning are inhaled. These changes to ME-0567, Rev. 1 require that the UFSAR be updated. In addition, engineering transmittal N 01-108, Rev, 0, has been prepared as a supplement to calculation ME-0567 in order to document the acceptability of the NALCO 2894 Algicide with respect to Control Room habitability and provide the maximum expected chemical concentrations in the Control Room following a chemical spill.

**Summary**

<u>Background</u>

PI N-2001-0397 required the revision of calculation ME-0567, Rev. 1 to correct several mathematical errors. These errors impact the maximum expected concentration in the control room following a chemical spill. Criterion 19 of 10CFR50, Appendix A, "Control Room," requires that the Control Room remain habitable during normal and accident conditions. As a result of the above changes, Engineering performed an evaluation to ensure Control Room habitability will be maintained following a chemical spill.

To support continuous BC blowdown during warm weather months, Calgon H-510 is being replaced with a copper-free form of Isothiazolin. This change was evaluated in ME-0567, Rev. 1, and in engineering transmittal N 01-108, Rev. 0.

The evaluation considered the following areas for each chemical addressed:

- Quantity, toxicity, and state in the plant.
- Chemical transport into the MCR via the emergency air intakes.
- Worst-case concentration level in the MCR

Calculation ME-0567, Rev. 1 was initiated to determine if any chemicals pose a threat to Control Room habitability. The calculation showed that all chemicals would have a Control Room concentration less than their toxicity limit in the event of a spill. The evaluation concluded that no chemical stored on site in a quantity over 100 pounds could adversely affect Control Room personnel following a release. Engineering Transmittal N 01-108 was prepared to document the acceptability of using a replacement chemical, NALCO 2894 Algicide, in the Bearing Cooling System, to be stored on site in chemical storage tank 1-BC-TK-3.

<u>Major Issues Considered</u>

**Probability or Consequences of Malfunctions** – No modifications are being made to plant systems and their operation as a result of this change. The evaluated condition has no impact on events or mechanisms that could initiate the accidents listed in the SAR. There are also no physical changes to plant systems and components that perform accident mitigation functions. An accident of a different type is not created as a result of this document change or the change in the biocide used in the BC system.

**Technical Specification / Operating License** – The Technical Specification sections relevant to Control Room Habitability are:

- Plant Systems, Control Room Emergency Habitability System Section 3.7.7.1, LCO and 4.7.7.1, Surveillance Requirements
- Plant Systems, Bases, Control Room Emergency Habitability System Sections 3/4.7.7

The Technical Specifications are not affected in any way by this change. The Mechanical Engineering evaluation and corresponding UFSAR changes document the safety of Control Room habitability with the on-site chemical storage configuration per VPAP 2202.

**Safe Shutdown Capability** – The SE and corresponding UFSAR changes are performed to ensure the safety of the plant based on an updated evaluation of the on-site chemical storage configuration. In addition, the storage of the biocide does not alter the operation of any system, component or structure as defined in the UFSAR. Because there are no physical modifications to the plant operating systems and components associated with the changes, there is no impact on the station's ability to achieve and maintain safe shutdown in the event of a fire. In addition, operation from the Auxiliary Shutdown Panel will not be adversely affected.

The use of Isothiazolin compounds in the concentrations commercially available does not present a fire hazard. Magnesium chloride and Magnesium Nitrate are chemical bi-products found in the biocides. Isothiazolin compounds and the chemical bi-products contained in the commercially available biocides are non-volatile in the available concentrations.

**Environmental Impact** – Mechanical Engineering has determined the plant to be safe with respect to the current chemical storage configuration. In addition, the replacement of Calgon H-510 with the NALCO 2894 Algicide or a copper-free biocide, equivalent to Calgon H-510 containing no more than 5% WT concentration of Isothiazolin compounds will not adversely affect the chemical storage configuration of the plant. Therefore, there will be no impact on the environment or the FES. Since no changes are being made to the plant operating systems or components, no changes in power level or effluents are expected. No change to the Environmental Protection Plan is required. Potentially increasing the % weight concentration of Isothiazolin compounds used in Calgon H-510 and Applied Specialties AS-590 from approximately 1.5 – 2.0% to 5.0%, or the use of NALCO 2894 Algicide containing a maximum 4.5% concentration of a slightly different Isothiazolin compound, will not violate our VPDES permit. The quantities of the biocide used in and discharged from the BC system are insignificant relative to the volumes of water involved, and there is no environmental impact.

For these reasons, these changes to the UFSAR & ME-0567 (Rev. 1) do not create an unreviewed safety question.

**01-SE-OT-12**

**Description**
UFSAR Change Request FN 2001-013
The UFSAR is being updated to include a revised 10 CFR 50.61 Pressurized Thermal Shock (PTS) screening calculation result for the North Anna Unit 2 reactor vessel weld material fabricated from weld wire heat 4278 (nozzle to intermediate shell weld 05A, OD 94%), with consideration given to Sequoyah Unit 2 plant-specific surveillance program data.

**Summary**
**PURPOSE**

The purpose of this Safety Evaluation document an evaluation of the application of Sequoyah 2 surveillance data to North Anna Unit 2 reactor vessel weld material fabricated from weld wire Heat 4278. The evaluation documented herein supports an update to the UFSAR description of the 10 CFR 50.61 Pressurized Thermal Shock (PTS) screening calculation result for the North Anna Unit 2 reactor vessel weld material fabricated from weld wire heat 4278 (nozzle to intermediate shell weld 05A, OD 94%).

**DISCUSSION**

10 CFR 50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events", requires that licensees "consider plant specific information that could affect the level of embrittlement." Sequoyah Unit 2 reactor vessel materials surveillance program analysis results have been incorporated into 10 CFR 50.61 PTS screening calculations, as well as into calculations that demonstrate the conservatism of analyses previously performed for compliance with 10 CFR 50 Appendix G, "Fracture Toughness Requirements". (See Technical Report NE-1274, Revision 0, "Application of Sequoyah 2 Surveillance Data to North Anna Unit 2 Reactor Vessel Weld Material Fabricated from Weld Wire Heat 4278, North Anna Unit 2," dated April 2001 (14).)

**SAFETY SIGNIFICANCE**

Dominion provided updates to the NRC's Reactor Vessel Integrity Database (RVID) by letters dated November 19, 1999 (1) and September 19, 2000 (2). The updates considered available reactor vessel materials surveillance data, including data obtained from the North Anna Units 1 and 2 plant-specific surveillance program as well as from other utilities' surveillance programs (3) (4) (5) (6). During review of proposed changes to the North Anna Units 1 and 2 Technical Specifications Reactor Coolant System (RCS) pressure/temperature (P/T) operating limits, Low Temperature Overpressure Protection System (LTOPS) setpoints, and LTOPS enabling temperatures ($T_{enable}$) (7) (8) (9), the NRC reviewer noted that Sequoyah Unit 2 surveillance data had been applied to the North Anna 1 Nozzle-to-Intermediate Shell Weld 05B (ID 6%) (1), but not to the North Anna 2 Nozzle-to-Intermediate Shell Weld 05A (OD 94%) (2). Both of these welds were fabricated with weld wire heat number 4278. The NRC reviewer agreed that the North Anna Units 1 and 2 Nozzle-to-Intermediate Shell Welds were non-limiting materials in terms of their Reference Temperatures for the Nil Ductility Transition ($RT_{NDT}$), but requested that Dominion provide updated RVID data tables that included explicit consideration of the Sequoyah 2 surveillance data for the North Anna Unit 2 weld fabricated from weld wire heat 4278.

Revised North Anna Unit 2 data tables for the NRC's Reactor Vessel Integrity Database (RVID) and an evaluation of changes relative to the previous RVID update for North Anna Unit 2 (2) have been prepared (14). The evaluation in Reference (14) considers the impact of the Sequoyah Unit 2 surveillance data on North Anna 2 (a) licensing basis reactor coolant system (RCS) pressure/temperature (P/T) limit curves, (b) the associated Low Temperature Overpressure Protection System (LTOPS) setpoints and enabling temperature, and (c) 10 CFR 50.61 Pressurized Thermal Shock (PTS) screening calculations. The evaluation is performed in a manner consistent with applicable regulatory guidance. Specifically, the calculation of the Reference Temperature for the Nil Ductility Transition ($RT_{NDT}$) is performed in accordance with Regulatory Guide 1.99 Revision 2 (11),

and the regulatory guidance provided in the meeting minutes from the November 12, 1997 NRC/Industry meeting on reactor vessel integrity (12). PTS screening calculations were performed in accordance with 10 CFR 50.61 (10). Supporting calculations are documented in Reference (13). Evaluation results are presented in a format consistent with the data requirements of the NRC's Reactor Vessel Integrity Database (RVID).

## CONCLUSIONS

The PTS screening calculation results for North Anna Unit 2 continue to meet the applicable screening criteria. Further, the $RT_{NDT}$ value used in the development of the current North Anna Unit 2 Technical Specification P/T limits, LTOPS setpoints, and LTOPS enabling temperature remains conservative.

By letters dated June 22, 2000 (7), January 4, 2001 (8), and March 22, 2001 (9), a Technical Specification change request was submitted to the NRC for the purpose of modifying the North Anna Units 1 and 2 P/T limits, and extending the cumulative core burnup applicability limits for the existing North Anna Units 1 and 2 LTOPS setpoints and LTOPS enabling temperatures. After consideration of the Sequoyah Unit 2 Capsule W analysis results, it has been determined that the $RT_{NDT}$ values previously provided to the NRC by letters dated November 19, 1999 (1) and September 19, 2000 (2) that support the aforementioned Technical Specification change submittal remain valid and conservative.

**The proposed UFSAR changes do not increase the probability of occurrence or consequences of accidents previously analyzed.** The proposed changes update the North Anna Unit 2 PTS screening calculations performed in accordance with 10 CFR 50.61. The 10 CFR 50.61 PTS screening criteria are met for all North Anna Unit 2 reactor vessel beltline materials. Therefore, the consequences of PTS events are not increased by the revised screening calculations. Reactor vessel material properties are not PTS event initiators. Therefore, the probability of occurrence of PTS events is not increased by the revised PTS screening calculation results.

**The proposed UFSAR changes do not increase the possibility for an accident of a different type than previously identified in the Safety Analysis Report.** The PTS screening calculations were performed in accordance with the methods prescribed by 10 CFR 50.61. None of the analysis parameters constitute new or unique accident initiators. Therefore, no possibility exists for creating an accident of a different type than previously analyzed in the Safety Analysis Report.

**The proposed UFSAR changes do not reduce the margin of safety.** Technical Report NE-1274 Revision 0 (14) demonstrates that the proposed revised analyses provide an acceptable margin of safety.

Required UFSAR changes are documented in UFSAR Change Request FN 2001-013.

**01-SE-OT-13**

**Description**
Technical Specification Bases Change Request No. 290A - This Bases change will incorporate the plant-specific risk analysis performed to extend the allowed outage time, bypass time, and surveillance frequency for the following functional units: 1) RCP Pump Breaker Position (RTS Functional Unit 20 in Table 3.3-1), 2) ESFAS Loss of Power, 4.16 Kv Emergency Bus Undervoltage (Loss of Voltage) (Functional Unit in Table 3.3-3) and ESFAS Loss of Power, 4.16 Kv Emergency Bus Undervoltage (Grid Degraded Voltage) (Functional Unit 7.b in Table 3.3-3), and 3) Automatic Switchover to Containment Sump (Function 7 in our ITS submittal table 3.3.2-1).
Include a statement in the Bases to identify that a plant specific risk analysis was performed to support the increased AOTs and decreased surveillance frequencies for the functional units in block 4.

**Summary**
WCAPs noted in references 1, 2, and 3 document a Westinghouse study which recommended an increase in the surveillance intervals of the analog instruments to quarterly and the permissive interlocks to refueling, when protection setpoint drift data could be shown to remain within the assumptions of the applicable safety analyses. The NRC has approved the use of these WCAP's in licensing submittals to extend the surveillance intervals when supported by plant data. As approved by the NRC in amendments 221/202, dated 03/09/00, North Anna Plant Technical Specifications were revised to incorporate the relaxations of Allowed Outage Times, test times and reduced functional testing of the Reactor Trip System/ Engineered Safety Features Actuation System (RTS/ESFAS) protection circuitry consistent with the WCAP references. However, three of the functional units (RCP Breaker Position Trip Above P-7, Functional Unit 20 in Table 3.3-1), 2) ESFAS Loss of Power – 4.16 Kv Emergency Bus Undervoltage (Functional Units 7a – Loss of Voltage, and 7b – Grid Degraded Voltage in Table 3.3-3), and 3) Automatic Containment Sump Switchover (Function 7. in our ITS submittal) included and approved for the relaxations in the amendments were not fully evaluated in the reference WCAP and NRC SERs. Therefore, a plant-specific risk assessment was performed to establish a basis for implementing the approved relaxations for these functional Units.

The WCAP-14333P evaluated the impact of the relaxation of allowed outage times and completion times, and action statements on core damage frequency. The change in core damage frequency is 3.1 percent for those plants with two out of three logic schemes that have not implemented the proposed surveillance test interval, allowed outage times, and completion times evaluated in WCAP-10271 and its supplements. This analysis calculates a significantly lower increase in core damage frequency than the WCAP-10271 analysis calculated. This can be attributed to more realistic maintenance intervals used in the current analysis and crediting the AMSAC system as an alternative method of initiating the auxiliary feedwater pumps. Therefore, the overall increase in CDF is estimated to be 3.1% for the proposed changes per the Westinghouse generic analysis.

The NRC performed an independent evaluation of the impact on core damage frequency and large early release frequency. The results of the staff's review indicate that the increase in core damage frequency is small (approximately 3.2%) and the large early release frequency would increase by only 4 percent for 2 out of 3 logic schemes that have not implemented the proposed surveillance test interval, allowed outage times, and completion times evaluated in WCAP-10271 and its supplements.

The impact on the Probabilistic Risk Assessment (PRA) due to an increase in the RPS and ESFAS AOTs and surveillance interval from monthly to quarterly is considered minor. The evaluation used the North Anna PRA model to estimate an overall change in the CDF of approximately one percent. For configurations involving the instrumentation and protection components such as those addressed by this package, the Large Early Release Frequency (LERF) impact is typically bounded by the CDF impact. (Reference 6)

Amendments 221/202 to the North Anna TS approved the relaxations to the RPS and ESFAS instrumentation AOTs and surveillance frequencies. However, two of the functional units for the current

Technical Specifications and an additional function unit that is part of our ITS submittal were not modeled in the WCAP and therefore, required a plant-specific risk assessment to implement. This Bases change will document that a plant-specific risk assessment has been performed to establish the acceptable risk associated with the relaxations for these functional units.

The reactor trip function on RCP breaker position is not included in the PRA model. However, its unavailability was specifically evaluated with and without operator action, both above and below Permissive P-8. Both random and common cause failures were evaluated. In each case, the total signal unavailability is increased by about 60% by the proposed TS limits. The magnitude of the signal unavailability remains very small in every case. When these unavailabilities are used to estimate the risk sensitivity, their net impact is negligible. This latter point is made clear by comparison to the risk sensitivity of the trains of reactor protection, which are individually NOT risk-significant. Individual components of the reactor protection system are of proportionally lower impact.

The undervoltage/degraded voltage (UV/DV) EDG start is modeled and may be assessed more rigorously. Both the UV and the DV signals were evaluated. The net impact of the proposed TS change is an increase in the EDG start-failure probability of approximately 0.8 percent. This failure mode is only marginally risk significant in a zero-maintenance configuration. The increase in start failure probability yields a CDF increase on the order of only 0.01% or <1E-8/yr.

The reactor trip function on RCP breaker position, the EDG auto-start on UV/DV, and the Automatic Switchover to Containment Sump are minor contributors at most to the core damage frequency. The proposed increases in their TS STIs and AOTs have a negligible impact on CDF with a combined impact of only about 0.01%. These sensitivities are easily bounded by the generic and plant-specific analyses previously reviewed and approved by the NRC for similar functions.

The Automatic Switchover to Containment Sump occurs when the Refueling Water Storage Tank level drops to the established setpoint. This function is not presently included in the North Anna Technical Specifications, but it will be included when North Anna converts to the Improved Technical Specifications. Thus, the Automatic Switchover to Containment Sump is being addressed in this submittal. Its failure probability is estimated to increase by approximately 1.3E-4 as a result of the proposed changes. However, the Automatic Switchover to Containment Sump function has a negligible risk impact in the zero-maintenance configuration. This minor increase in its unavailability also results in a negligible CDF impact.
This Bases change supplements the original Technical Specifications change (Amendments 221//202) which relaxed the AOTs and modified the surveillance frequency requirements for the RTS and ESFAS analog instrument channels, including the EDG UV/DV start circuitry. As noted above, a plant-specific risk assessment was performed for those channels that were not included in the original WCAP-10271, Supp 1 and 2 and WCAP-14333P risk analysis to establish the basis for the relaxations. In addition, the following summarizes the safety evaluation determination of no unreviewed safety question.

> The increase in the allowed outage and maintenance times for the RTS and ESFAS analog instrumentation and the actuation logic and the reduced surveillance frequency have no impact on the probability of occurrence of any accident previously evaluated in chapter 15 of the UFSAR. The RTS and ESFAS Systems including the EDG UV/DV start circuitry will continue to be operated in the same manner.
>
> The increase in the allowed outage and maintenance times for the RTS and ESFAS analog instrumentation, the actuation logic and EDG UV/DV start circuitry have no impact on the consequences of the accident identified herein. The data review specifically confirmed that quarterly instrument drift remains within the assumptions of the protection setpoint analysis. As such, the setpoints remain adequate to ensure that all accident consequences remain within acceptable levels. All safety components, structures, and systems will be operable as assumed in the safety analysis to mitigate the consequences of the previously evaluated accidents. Therefore the consequences of the accidents identified above are not increased by the changes to the AOTs, bypassed times,

surveillance interval for the RTS and ESFAS analog instrumentation, actuation logic and interlocks, and EDG UV/DV start circuitry.

The RTS and ESFAS Systems, including the EDG UV/DV start circuitry, will continue to be operated in the same manner. The increased allowed outage and maintenance times for the analog instrumentation channels and the automatic actuation logic and the decreased surveillance frequencies for the analog instrumentation channels do not establish any new method of plant operations. Therefore, no new modes of operation or accident precursors are generated by the proposed Technical Specification changes.

No hardware or procedural changes will be made which generate unique accident risk. The RTS and ESFAS Systems and EDG UV/DV start circuitry will continue to be operated in the same manner. The operability requirements and minimum redundancy requirements in the TS are maintained. Therefore, no new accident precursors or method of operation are generated by the proposed changes. Existing safety analyses remain applicable. Thus there is no reduction in the margin of safety.

**01-SE-OT-14**

**Description**
Technical Specification Change Request No. 389
References to Virginia Electric and Power Company in the North Anna Units 1 and 2 Operating Licenses and Technical Specifications will be changed to Dominion Generation Corporation as a result of the pending license transfer being prepared as part of the Dominion's functional separation into regulated and unregulated entities.

**Summary**
Virginia Electric and Power Company (Dominion Virginia Power) is transferring the licenses for its nuclear facilities to Dominion Generation Corporation pursuant to electric industry restructuring laws in the Commonwealth of Virginia, which require electric utilities in Virginia to separate generation from transmission and distribution functions. Dominion Virginia Power's generation facilities will be transferred to Dominion Generation Corporation, while Dominion Virginia Power will retain its transmission and distribution assets and functions. Consequently, conforming changes to the Facility Operating Licenses and accompanying Technical Specifications for North Anna Power Station Units 1 and 2 are necessary to reflect the transfer of ownership of North Anna Power Station to Dominion Generation Corporation. The proposed changes delete references to Virginia Electric and Power Company and variations thereof and replace them with references to Dominion Generation Corporation as the new owner and operator of North Anna Power Station and make minor changes that support the license transfers. No physical modifications are being made to plant systems or components nor are any changes in day-to-day operation of the units being affected. The personnel responsible for the safe operation of the plant will not change as a result of the license transfer. Therefore, the proposed changes are solely administrative in nature and will not adversely affect nuclear safety or safe plant operation. Consequently, an unreviewed safety question does not exist.

**01-SE-OT-15**

**Description**
UFSAR Change Request No. FN 2001-007
The proposed UFSAR change incorporates the criteria and methodology of Generic Implementation Procedure (GIP) developed by the Seismic Qualification Utility Group (SQUG) and endorsed by the NRC in their Safety Evaluations. The GIP methodology, with some enhancements, can be used as an alternative to the current licensing basis methods for seismic design and verification of existing, modified, new and replacement equipment and components. The UFSAR change also includes a brief description of median-centered in-structure spectra that can be used in evaluations using the GIP, and minor editorial changes.

**Summary**
The proposed change to the UFSAR is being made to allow the use of the GIP method as a cost-effective alternative method for demonstrating seismic adequacy of equipment. Relative to the current North Anna licensing basis, the GIP method, with additional considerations, results in an equivalent or superior level of assurance that equipment will perform the required safety functions during and after a seismic event. Therefore, the following applies:

- The impact of the proposed change is considered on a seismic event as a potential accident initiator and the change will have no impact on a seismic event as a potential initiator of accidents previously analyzed in the UFSAR.
- The only accidents in the SAR that could potentially be affected by the use of the GIP method are the Operating Basis Earthquake (OBE) and the Design Basis Earthquake (DBE). However, the GIP method, being a method for demonstrating seismic adequacy of equipment, will not increase the likelihood of the occurrence of an OBE or a DBE. Therefore, with respect to the seismic event as an occurrence, the proposed change will not increase the probability of occurrence of a seismic event because this event is the result of natural phenomena.
- Assumptions in previously analyzed accidents in the USAR regarding availability and performance of equipment to mitigate an accident following a seismic event are unchanged. Therefore, the proposed change does not increase the consequences of an accident previously evaluated in the UFSAR.
- The only accidents in the UFSAR that could potentially have radiological release consequences affected by the use of the GIP method are those accidents analyzed in the UFSAR associated with the Operating Basis Earthquake and the Design Basis Earthquake. However, as described above, the proposed change will have no effect on them and will change no accident consequences.
- Use of a new method for demonstrating equipment seismic adequacy could potentially affect the ability of safety-related equipment or equipment important to safety to perform required safety functions during or after a seismic event, thus affecting radiological release consequences. However, the use of the GIP method will provide equivalent or superior assurance of equipment seismic adequacy to that provided by the current North Anna licensing basis. Thus, use of GIP will have no effect on radiological release consequences.
- The UFSAR requirements regarding seismic adequacy of equipment include a subset of equipment (i.e., safety-related and NSQ) that must meet seismic adequacy requirements. The UFSAR also discusses the method for demonstrating seismic adequacy. The proposed change will provide an alternative method for demonstrating seismic adequacy and does not change the subset of equipment that must meet seismic adequacy requirements. The change will continue to ensure that regulatory requirements regarding seismic adequacy of equipment are met.
- The proposed change does not affect the set of equipment that must meet seismic adequacy requirements or the level of seismic adequacy as defined in the UFSAR, therefore, it does not create the possibility of an accident of a different type than previously evaluated in the UFSAR.
- Malfunction of safety-related or NSQ equipment previously evaluated in the UFSAR is considered to ensure that such equipment would perform required safety functions during and after a seismic event. No equipment important to safety is affected by the proposed change. Therefore, the proposed change will not increase the probability of occurrence of a malfunction of equipment important to safety previously evaluated in the UFSAR.

- The GIP method provides an equivalent or superior level of assurance that equipment will withstand various potential seismic failure modes. Further, as discussed in Appendix A, the GIP method addresses specific seismic failure modes identified during real earthquakes that are not addressed in the current North Anna licensing basis method. The proposed change will not introduce any new equipment failure modes and thus does not create the possibility of a malfunction of equipment important to safety of a different type than any previously evaluated in the UFSAR.
- No change to Operating License or Technical Specifications is required.
- The proposed change does not affect the ability of the Station to achieve and maintain safe shutdown in the event of a fire.
- The proposed change does not cause any adverse environmental impact whether previously evaluated or not in the FES.
- The proposed change will not involve any change in effluents or power level
- The proposed change will not cause any change to the environmental protection plan.

The safety evaluation herein shows that no unreviewed safety question is created by this UFSAR change and, as such, the use of the GIP method is acceptable. The use of the GIP will not affect the ability of safety-related equipment or equipment important to safety to perform required safety functions during or after a seismic event. The background information associated with this evaluation is summarized as follows.

**GIP has been reviewed and accepted by the NRC** – The GIP method has been extensively reviewed. GIP-2 was approved by the NRC [4] for resolution of USI A-46, which was issued by the NRC to address concerns with early seismic qualification techniques.
The NRC has also approved GIP-3 in SSER NO. 3 [5].

**GIP meets the intent of the regulations** – The methods used in GIP-2 and GIP-3 have been reviewed and accepted by the NRC for Unresolved Safety Issue (USI) A-46 plants in SSER No. 2 [4] and SSER No. 3 [5]. In SSER No. 2, the NRC stated that the GIP-2 methods "satisfy the pertinent seismic requirements of General Design Criterion 2 and the purpose of the NRC regulations relevant to equipment seismic adequacy including 10 CFR Part 100." This SSER No. 2 statement covers application of GIP-2 to not only existing as-installed equipment in USI A-46 plants, but also new and replacement equipment which may be installed in USI A-46 plants.

To demonstrate that the use of the GIP will not result in an unreviewed safety question or in a reduction of safety margin relative to the North Anna licensing basis, a detailed comparison of the GIP with key elements of the North Anna licensing basis is performed. This comparison is shown in Appendix A to this safety evaluation. Differences between the GIP method and the North Anna licensing basis are identified and the effect of the differences on the overall cumulative relative safety margin is determined. The results demonstrate that the use of the GIP method will not reduce plant margin of safety.

**01-SE-OT-16**

**Description**

UFSAR Change Request FN 2001-011

The change is to chapter 9.5.1 of the UFSAR, Fire Protection System, with an additional minor change to Chapter 3.5, Missile Protection Criteria. The change will consist of revisions to the description for manual foam hose streams for the protection of the Fuel Oil Storage Tank, so that it is consistent with current fire fighting strategies. In addition, a reference to a halon system within the records storage room will be deleted, since the records stored there and the halon system have been removed. Associated with that change, will be the addition of a description of the preaction sprinkler system protecting the records room within the Records Building. Lastly, the description of SCBA's used for fire fighting will be clarified.

**Summary**

Nuclear Oversight Audit 01-02 identified some discrepancies within section 9.5.1, Fire Protection System, of the UFSAR. These discrepancies consist of an inadequate description of foam hose stream capabilities for protection of the Fuel Oil Storage Tank (9.5.1.2.1 and 9.5.1.3.1.2), an incorrect reference to a halon system that has been removed (9.5.1.4.1.2), and an unclear description of SCBA's used for fire fighting (9.5.1.2.4.4). The changes will correct and clarify these discrepancies, such that the UFSAR descriptions are consistent with current fire protection equipment and capabilities.

Unit 1 license condition 2.D.(3).u and Unit 2 license condition 2.C.(23) allow the Licensee to make changes to the fire protection program if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire. The ability to achieve and maintain safe shutdown in the event of a fire will not be degraded. The UFSAR describes using a foam hose stream to protect the Fuel Oil Storage Tank from a nearby hose house. The foam hose stream, if needed, will be supplied from one of the portable foam carts available on site. In addition, the UFSAR describes a halon system for the records room in the office building. The records have been removed from this room; therefore, the halon system was no longer needed, and has been removed. The records are now stored within the records room in the Records Building. Adequate fire suppression is provided for this room in the form of an automatic preaction sprinkler system. This is in conformance with Reg. Guide 1.88 and NFPA 232-1975, as described in Chapter 17 of the UFSAR. The method of operation for SCBA use for fire fighting has not been changed.

The change to the method used for applying foam hose streams to the Fuel Oil Tank and Pumphouse does not adversely affect the ability to manually combat a fire on the tank or within the pumphouse. The original description for the use of a manual foam hose stream did not specify the quantity of foam required. A review of the original specification, NAS 266, identified the original intent was for a manual foam hose stream for spill protection of the Fuel Oil Storage Tank and Pumphouse. In both cases, the system was intended to be a back-up suppression system to the fixed suppression systems installed. NAS 266 specified the use of 5 gallon cans of concentrate to produce the foam hose stream. A total of ten, 5 gallon cans, were specified to be contained within the hose house. The existing portable units contain 32 gallons of foam, and have an approximate discharge time of 18 to 20 minutes. There are a total of 4 - 32 gallon portable units available for fire brigade use. In addition, the change to the fire fighting strategy provides greater flexibility to the fire brigade for providing a foam hose stream on the Fuel Oil Storage Tank or Pumphouse. The use of portable units will allow the brigade to use any nearby hydrant they chose. This ensures a foam hose stream can be applied even if access to one hydrant is blocked by smoke and flames. A sufficient quantity of foam is available on site, and can be quickly retrieved by the fire brigade, to combat a fire on the Fuel Oil Storage Tank or adjacent pump room. As a result, the existing foam hose stream capabilities exceed those original specified within NAS 266, and described within the UFSAR.

The elimination of the halon system does not decrease the protection within the Office Building area since the records storage has been moved. Adequate suppression has been provided for the records within the Records Building. The changes to the description of SCBA's are administrative, and do not impact their function or operation. The UFSAR changes do not impact the station's compliance with 10CFR50

Appendix R, and it's ability to safely shutdown in the event of a fire. The changes do not relax established requirements or change the method in which safe shutdown is achieved and maintained.

The current North Anna License condition allows the licensee to make changes to the fire protection program without NRC approval if those changes do not adversely affect that ability to achieve and maintain safe shutdown in the event of a fire. The ability to achieve and maintain safe shutdown will not be adversely affected. 10CFR50, Appendix A, General Design Criteria (GDC) 3, discusses the minimum level of fire protection that must be maintained at the station. This change will eliminate the halon system for the office building records room. This is acceptable since the records have been removed from this area. The capability to apply a foam hose stream to the Fuel Oil Storage Tank and pumphouse has not been adversely affected, only the description on the equipment used to achieve this has changed. All systems and equipment relied upon to meet Appendix R requirements will continue to be in place and operable. There will be no adverse impact on the station's compliance with GDC 3. This change does not create or impact an unreviewed safety question.

**01-SE-OT-18**

**Description**

Change Request No. FN-2001-005 for North Anna Units 1 and 2 UFSAR Section 15.2.7, "Loss of External Electric Load and/or Turbine Trip," Table 15.2-1 and the associated figures.

This safety evaluation supports a revision to Section 15.2.7 and the associated table and figures of the North Anna Units 1 and 2 Updated Final Safety Analysis Report (UFSAR). The loss of load accident reanalysis was performed using updated in-house analysis techniques within the constraints of applicable analysis requirements.

**Summary**

PURPOSE

This Safety Evaluation supports a revision to Sections 15.2.7, "Loss of External Electric Load and/or Turbine Trip," Table 15.2-1 and the associated figures of the Updated Final Safety Analysis Report (UFSAR), for North Anna Units 1 and 2 .

BACKGROUND

This safety evaluation has been prepared to support the incorporation of a revised UFSAR description of the Loss of External Electric Load and/or Turbine Trip (LOL) accident analysis. The primary technical reference for the revised UFSAR description is Calculation SM-1259, Revision 0 (Reference 1), which summarizes an updated LOL accident analysis for North Anna Units 1 and 2. Calculation SM-1259, Revision 0 was prepared to revise UFSAR Sections 15.2.7, Table 15.2-1 and the associated figures. These updated analysis techniques include: (a) Use of RETRAN2, Mod5.2 code on IBM-AIX 4.3.2 platform instead of IBM main frame; (b) Use of Local Condition Heat Transfer model in the secondary side of steam generator, and (c) Use of decay heat model based on ANSI 1979 decay heat model.

SUMMARY OF LOL ACCIDENT ANALYSIS

The Loss of Load/Turbine Trip transient is a heatup event resulting from loss of external electrical load or a turbine trip. This causes a rapid reduction of steam flow from the SG resulting in a quick rise in secondary side pressures and primary side temperatures and pressures. The transient is terminated either by a direct Rx trip or, in the limiting case, a Rx trip on high pressurizer pressure. The primary and secondary side pressure relief systems are confirmed to be adequate to limit the maximum pressures to within design limits. The transient continues to have ample margin to the core thermal limits and is not limiting with respect to core thermal margins.

During this event, offsite power is assumed to be available for the continued operation of plant components such as the RCPs. The case of the transient occurring with loss of all offsite power is covered under the Loss of Offsite Power event.

One case of the Loss of External Electric Load and/or Turbine Trip analysis is performed to demonstrate that the limiting minimum DNBR is above the acceptance criterion. Another case assesses the limiting reactor coolant and main steam system peak pressures against their respective acceptance criteria. As a result of this analysis, the peak cold leg pressure decreased from 2740.4 psia to 2737.5 psia, the peak steam generator pressure decreased from 1184.4 psia to 1174.6 psia. The MDNBR increased from 2.15 to 2.186. The accident analysis satisfies the applicable event acceptance criteria.

With respect to the proposed revision to the UFSAR description of the LOL accident analysis, the following conclusions are applicable:

a. The probability of occurrence of the LOL accident is not increased by the incorporation of the revised UFSAR Section 15.2.7 description of the accident analyses, Table 15.2-1 and the associated figures. The proposed UFSAR text relies on existing Technical Specification and procedural requirements to ensure that

the LOL accident analysis remains valid. No system configuration, design or method of operation is being changed. Therefore, it is concluded that the probability of occurrence of the LOL accident is not increased.

b. The implementation of the proposed changes to the UFSAR section does not create the possibility of an accident of a different type than was previously evaluated in the SAR. All applicable accident analysis acceptance criteria, including accident propagation criteria, will continue to be met. No system configuration, design or method of operation is being changed. No new or unique accident precursors are introduced. The proposed changes that will not compromise the ability of operators to control the plant under normal and accident conditions since the heat removal capacity of the system remains adequate.

c. The margin of safety in the LOL accident analyses is not reduced by the incorporation of the revision to UFSAR Section 15.2.7, Table 15.2-1 and the associated figures. The proposed UFSAR change does not change the plant configuration or mode of operation. The accident analysis for the LOL event shows adequate margin to the event acceptance criteria. Therefore, the margin of safety will not be reduced by the implementation of the proposed UFSAR change.

**01-SE-OT-19**

**Description**
Technical Requirements Manual, Section 12.2, EQ Doors
The change to the Technical Requirements Manual (TRM) is the result of revisions to the Probabilistic Safety Assessment, clarifications and the evolution of the EQ Barrier Program. These changes are administrative in nature and are designed to aid the user in understanding the restrictions and limitations of the Program.

**Summary**
The change being evaluated is a revision to the Technical Requirements Manual, Section 12.2, EQ Doors. The change to the TRM is the result of revisions to the Probabilistic Safety Assessment (PSA), clarifications and the evolution of the EQ Barrier Program. These changes are administrative in nature and are designed to aid the user in understanding the restrictions and limitations of the Program.

Four (4) EQ Doors which are not captured in the Probabilistic Safety Assessment, as they are maintained closed and locked are added with a note stating such. These doors are being added to provide a more comprehensive list of EQ Doors. Plant Issue N-2000-2032 identified that not all EQ Doors were listed in the TRM. One of the initial actions incorporated two (2) additional doors, which had been added in the PSA but had not been incorporated into the TRM at that time.

Specifically:
Note a. on page 12.2-3 is being revised to ensure only one door is breach at a time unless evaluated by Engineering.

Note c. on page 12.2-3 is being revised to add Chiller Room doors. The doors separating the ESGR 1 & 2 and the Chiller Rooms were added by a revision to the PSA. The same restrictions applied to the Unit 2 ESGR to the Turbine Building apply to these doors as the Potentially Harsh Environment (Turbine Building) and the affects on equipment are the same.

Note c. & d. on page 12.2-3 are being applied to the doors separating the ESGR 1 & 2 and the Chiller Rooms. These notes were originally applied to the door separating the ESGR-2 to Turbine Building, but as stated above these two (2) doors and areas are subject to the same Harsh Environment.

Revised note b. on page 12.2-4 for clarity and readability.

Added note c. to page 12.2-4 to clarify the EQ Door Breach Duration of 16 hours for the two (2) doors in the Unit 2 ESGR is a total for the zone not 16 hours per door.

Added four (4) doors to Table 12.2-2 on page 12.2-4 to provide a more complete list of EQ Doors. They are:

| | |
|---|---|
| 01-BLD-STR-A59-1 | Electrical Penetration Area Unit 1 to Auxiliary Building |
| 01-BLD-STR-A80-1 | Control Rod Drive Room Unit 1 to Auxiliary Building |
| 01-BLD-STR-A59-2 | Electrical Penetration Area Unit 2 to Auxiliary Building |
| 01-BLD-STR-A80-2 | Control Rod Drive Room Unit 2 to Auxiliary Building |

Added note d. to page 12.2-4 to inform the user the doors added to Table 12.2-2 (above) do not have PSA time as they are normally maintained closed and locked. A breach to these doors requires a separate Engineering evaluation on a case by case basis.

This TRM revision is administrative in nature intended to provide a more comprehensive profile of the EQ Door Program. These changes do not direct any Operator actions. The EQ Barrier/Door Program is administered by Engineering and controlled via VPAP-0305. The sections of the TRM being revised are informative only. As a result, there is no unreviewed safety question **created by this TRM revision.**

**01-SE-OT-20**

**Description**
Fuel Anomaly NDC01-9 Addendum 2
Fuel Anomaly NDC01-9 Addendum 2 documents NAF's intention to conditionally remove the handling restrictions from fuel assemblies that were identified in references 3 and 5 as susceptible to Intergranular Stress Corrosion Cracking (IGSCC) of thimble sleeves based upon the results of video inspections.

**Summary**
Reference 2 provides video inspection acceptance criteria for conditionally removing the handling restrictions from fuel assemblies that were identified in references 3 and 5 as susceptible to Intergranular Stress Corrosion Cracking (IGSCC) of thimble sleeves. Reference 2 concludes that fuel assemblies that have no indications of reddish-brown oxide, cracking, or other abnormalities at the bulge joints attaching the guide thimble to the top grid sleeves may be moved using the normal spent fuel tool. Fuel Anomaly NDC01-9 Addendum 2 documents NAF's intention to remove the handling restrictions from inspected fuel assemblies that meet the video inspection criteria documented in Reference 2. This will allow fuel assemblies that are susceptible to IGSCC to be moved using the normal spent fuel tool and established procedures. Reference 2 indicates that the visual inspections are currently considered valid only until the fuel is handled using the normal tooling or for three months, whichever comes first, after which the bulge joints should be re-inspected to confirm their integrity before moving the assembly using the normal spent fuel tool. The handling status of fuel assemblies susceptible to IGSCC will be controlled by References 4 and 8.

The activity evaluated involves the movement of irradiated fuel in the spent fuel pool using the normal spent fuel tool. Section 15.4.5 of the UFSAR, Fuel-Handling Accident Outside Containment, discusses the applicable accident analysis. The accident is described and analyzed therein as the drop of a freshly discharged fuel assembly (100 hours after shutdown) leading to the damage of all the rods in the fuel assembly and the subsequent release of activity.

The proposed activity involves movement of assemblies that have been in the spent fuel pool in excess of one year. Therefore there is no iodine source term associated with these assemblies; additionally the whole body doses associated with the failure of all rods in the assembly would be significantly less than analyzed in the UFSAR. Therefore the consequences cannot be increased.

The probability of occurrence of the accident identified above cannot be increased by the proposed activity by virtue of several independent considerations, namely:

1) The probability of dropping a **fuel assembly** is not increased, because the visual inspection program approved in Safety Evaluation 01-SE-PROC-11 (Reference 1) is designed to identify fuel assemblies in the population susceptible to thimble sleeve stress corrosion cracking that exhibit corrosion. Only assemblies that do not exhibit signs of corrosion are being removed from handling restrictions. In accordance with Reference 2, the handling restriction is removed for a period of 3 months provided no additional handling occurs during that period. If additional handling is required, or the 3 month period expires then new video inspections are required to verify that no degradation of the thimble sleeve has occurred. Assemblies that exhibit signs of corrosion remain restricted from handling in the normal manner. Thus eliminating the potential to drop a fuel assembly due to thimble sleeve failure.

2) The probability of dropping a **freshly discharged** fuel assembly is not increased. The assemblies in question have all been in the spent fuel pool for in excess of one year. Note that there is no I-131 source term in these assemblies, so the accident defined, identified and analyzed in the UFSAR (drop of a **freshly discharged** fuel assembly (100 hours after shutdown)) cannot have its probability increased.

The safety evaluation also considered several malfunctions of equipment important to safety. 1) Failure to divert fuel building exhaust to the particulate and activated charcoal filter. 2) Failure of the monitors to alarm on a high radiation level to indicate a possible dropped-fuel-assembly incident. It was concluded that

moving the assemblies in question would have no effect on the availability and reliability of equipment important to safety. Also, since the assemblies in question have all been in the spent fuel pool for in excess of one year there is no I-131 source term in these assemblies, so there are no consequences of losing these design features.

Finally, since the results of the UFSAR fuel handling accidents remain unchanged by this proposed activity, there is no reduction in safety margin.

**01-SE-OT-22**

**Description**
Technical Requirements Manual (TRM) Change Request # 45, ET N-00-0138, Rev 0. Deviation / Plant Issue Report: N-99-0774. NAPS Appendix R Report
Changes to the TRM are the result of revisions needed to clarify: a) Appendix R / Fire Protection compensatory measures, b) Fire Brigade manning, and c) Appendix-R Alternate Shutdown Equipment fire watch locations and their bases.

**Summary**

This Safety Evaluation supports changes / enhancements to applicable sections of the North Anna Technical Requirements Manual (TRM) relative to: a) Appendix R / Fire Protection compensatory measures, b) Fire Brigade manning, and c) Appendix-R Alternate Shutdown Equipment Fire Hose Station locations and their bases.

During planning to replace fire protection isolation valve 1-FP-157, per Work Order # 00356864-01, it was noted that verbatim compliance with TRM 7.1.5 was not reasonably achievable. The replacement of this valve would require all the fire hose stations within the Auxiliary Building to be inoperable. The existing compensatory measures required that additional equivalent capacity fire hose be routed to the Auxiliary Building from operable hose stations. This could not reasonably be achieved. As a result, ET N-00138, Rev-0 was developed to provide alternative required actions involving: a) the establishment of an hourly fire watch and b) staging additional fire protection mandated by the Safety and Loss Prevention Department.

A re-assessment of a recent revision to TR 7.3, requiring that two of the five Fire Brigade members per shift be from the Security Department was determined to undermine the smooth operation of the Brigade and has subsequently been deleted. Further review noted that 10 CFR 50, Appendix R, and North Anna Emergency Procedures only require that the Fire Brigade have at least five (5) qualified members on each shift and that the brigade leader and at least two (2) brigade members have sufficient training in or knowledge of plant safety-related systems to understand the effects of the fire and fire suppressants on safe shutdown capability, and these requirements remain in the TRM.

Deviation Report N-99-0774 identified inadequacies associated with TRM 7.5 relative to Appendix R Alternate Shutdown Equipment. Corrective actions included in ET N-00138, Rev-0, consisted of providing better descriptions, including footnotes, for Fire Watch Locations in Table 7.5-1, as well as the development of a Bases to further describe Appendix R Alternate Shutdown Equipment.

Unit 1 License condition 2.D. (3). u and Unit 2 License Condition 2.c.(23) allow the Licensee to make changes to the fire protection program if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire. The ability to achieve and maintain safe shutdown in the event of a fire will not be degraded. The recommended changes enhance compensatory measures for alternate shutdown equipment and fire hose stations, and provide a bases for the fire watch locations listed for alternative shutdown equipment. The changes to the Compensatory measures within TRM 7.1.5, Fire Hose Stations are necessary to allow normal maintenance on fire protection components. The additional, proposed, compensatory measure provides an equivalent measure of protection to those existing. As a result, the changes do not relax established requirements or change the method in which safe shutdown is achieved and maintained.

The current North Anna License condition allows the licensee to make changes to the fire protection program without NRC approval if those changes do not adversely affect that ability to achieve and maintain safe shutdown in the event of a fire. The ability to achieve and maintain safe shutdown will not be adversely affected since the changes do not affect the ability of any system to function as designed. 1OCFR50, Appendix A, General Design Criteria (GDC) 3, discusses the minimum level of fire protection that must be maintained at the station. This change will not eliminate any fire protection

system or equipment. All systems and equipment relied upon to meet Appendix R requirements will continue to be in place and operable. There will be no adverse impact on the station's compliance with GDC 3. This change does not create or impact an unreviewed safety question since this is a document update that enhances compensatory measures and provides a bases for alternative shutdown equipment compensatory measures.

**SAFETY EVALUATION LOG**
**MODIFICATIONS**
**2001**

| S.E. # | Unit | Document | System | Description | SNSOC Date |
|---|---|---|---|---|---|
| 95-SE-MOD-13 | 1,2 | DCP 94-159-3 | | Pressurizer Heater Electrical Repairs | 3-2-95 |
| 95-SE-MOD-53 | 1,2 | DCP 95-131 | | Nuclear Building Ground Water Intrusion | 8-1-95 |
| 95-SE-MOD-80, Rev. 3 | 1,2 | DCP 95-015 | | Refurbishment of Service Water Pumps | 4-24-97 |
| 95-SE-MOD-83 | 1,2 | DCP 94-271 | | Fire Damper Modifications | 12-14-95 |
| 96-SE-MOD-06 | 1,2 | DCP 95-242 | | Removal of Containment Concrete Floor Plugs | 2-5-96 |
| 96-SE-MOD-20 | 1,2 | DCP 94-010, Field Change No. 1 | | Repair/Replacement of Exposed Service Water Piping to / from Component Cooling Heat Exchangers | 3-14-96 |
| 96-SE-MOD-23 | 2 | DCP 95-190 | | Refueling Water Storage Tank / Casing Cooling Tank Manway Strongbacks | 4-15-96 |
| 96-SE-MOD-33, Rev.1 | 2 | DCP 95-002 | | Condensate Polishing System Upgrades | 8-7-96 |
| 96-SE-MOD-34 | 1,2 | DCP 95-216 | | Charging Pump Discharge Head and Seal Housing Replacements | 7-3-96 |
| 97-SE-MOD-34, Rev. 1 | 2 | DCP 97-003 | | Component Cooling Heat Exchanger Replacement | 12-5-97 |
| 98-SE-MOD-10 | 2 | DCP 97-014 | | Outside Recirculation Spray Pump Motor Replacement | 3-30-98 |
| 99-SE-MOD-03 | 2 | DCP 99-125 | | Relocate Recirculation Spray Pump Temporary Test Dike Panel Storage for Installation of Reactor Head Stand Water Shields | 4-1-99 |
| 99-SE-MOD-05 | 2 | DCP 98-172 | | Install Recirculation Spray Heat Exchanger Service Water Check Valve Inspection Ports | 4-15-99 |
| 99-SE-MOD-06 | 1,2 | DCP 99-106 | | Security System Magnetic Door Lock Enhancements | 6-10-99 |
| 99-SE-MOD-12 | 1,2 | DCP 99-119 | | Blowdown System Upgrade | 7-29-99 |
| 99-SE-MOD-14 | 1 | DCP 99-135 | | Lube Oil Sample Test Ports | 8-3-99 |
| 99-SE-MOD-19 | 1,2 | DCP 99-142 | | Charging Pump Minimum Flow Recirculation Orifice Replacement | 8-24-99 |

## SAFETY EVALUATION LOG
## MODIFICATIONS
## 2001

| S.E. # | Unit | Document | System | Description | SNSOC Date |
|---|---|---|---|---|---|
| 99-SE-MOD-20 | 1,2 | DCP-98-007 | | Feedwater Flow Calorimetric | 8-24-99 |
| 99-SE-MOD-21 | 2 | DCP 99-145 | | Permanent Installation of Thermocouple Cards into 2-MUX-21A | 8-31-99 |
| 99-SE-MOD-24, Rev. 1 | 1 | DCP 97-007 | | Main Generator Redundant Protection and Negative Sequence Detection / Alarm | 3-29-00 |
| 99-SE-MOD-28, Rev. 1 | 1,2 | DCP 99-130 | | Auxiliary Building Central Area Exhaust Damper Instrument Air and Electrical Power Modification | 5-16-00 |
| 00-SE-MOD-13 | 2 | DCP 00-138 | | Reactor Vessel Level Indication System (RVLIS) Sensor Bellows Reorientation | 10-3-00 |
| 00-SE-MOD-14 | 2 | DCP 00-148 | | Main Feedwater Regulating Valve Actuator Air Supply Modification | 10-5-00 |
| 00-SE-MOD-16 | 1,2 | DCP 00-005 | | Modifications to NUREG-0612 Special Lifting Devices | 11-8-00 |
| 01-SE-MOD-02 | 1,2 | DCP 99-006 & test plan<br>UFSAR FN 99-065<br>PI N2000-2146<br>Special Rpt 01-295<br>HP-3010.040<br>HP- 3010.031<br>HP PT-453.01<br>HP PT-406.01<br>0-NAT-I-002<br>0-NAT-M-005<br>EPIP-1.01; EPIP-4.08; EPIP-4.09; EPIP-4.24<br>EALs B-4, B-7, C-7, C-9, E-3, E-5, G.1 & G-2<br>VPAP-2103 (N)<br>0-WP-G99006 | | Replaces the current Kaman process & vent stack particulate, iodine, & gaseous radiation monitors 1-GW-RM-178, 1-VG-RM-179, & 1-VG-RM-180 with a radiation monitor system manufactured by MGP Instruments. Currently installed Westinghouse, NRC, & General Atomic radiation monitors 1-GW-RM-101/102, 1-VG-RM-103/104, & 1-VG-RM-112/113 will be removed. | 7-17-01 |

**95-SE-MOD-13**

**Summary**
DCP 94-159-3 authorizes a different method of making electrical connections to the pressurizer heaters. This method utilizes brazing the lug instead of using standard mechanical hardware. Also the replacement of damaged and shortened high temperature cables with a new type.

**Description**
The pressurizer heater connections have been demonstrating an unacceptable failure rate due to corrosion. The new connection method combined with the Cu/Ni alloy of the new replacement cable should reduce the corrosion resulting in improved pressurizer heater reliability. Further, some of the cable replacements and connector repairs should allow restoration of some heaters that have been left disconnected due to the damage caused by the connector failures.

An unreviewed safety question does not exist because:

- The implementation of this DCP will not increase the probability of occurrence or the consequences of an accident or malfunction of equipment important to safety and previously evaluated in the UFSAR because the components being modified are not safety-related. The different cable terminations are like for like. The replacement cables are like for like with qualified material.
- The implementation of this DCP will not create a possibility for an accident or a malfunction of a different type than any evaluated previously in the UFSAR because the individual components will operate the same as before and will not be exposed to any different risk factors than before. The termination method is expected to provide improved reliability.
- The implementation of this DCP will not reduce the margin of safety as defined in the basis of any Technical Specification because the ability of the pressurizer heaters to contribute to their Technical Specification role will not be altered and may be enhanced by virtue of improved reliability.

**95-SE-MOD-53**

**Summary**
DCP 95-131, Nuclear Building Ground Water Intrusion
The purpose of the design change is to eliminate ground water intrusion into various plant buildings. This will minimize the amount of ground water that is processed out of the building drains as liquid radwaste. It will also reduce the potential for the spread of contamination and improve area housekeeping.

**Description**
Various building expansion joints and concrete joints are leaking ground water. The leaking expansion joints will be disassembled for inspection and repair by removing the metal expansion joint cover and existing compressible joint filer material. The leak will be repaired by placinga compressible hydro active chemical grout foam expanded gasket within the expansion joint. The leaking concrete construction joints will be repaired by drilling small diameter holes adjacent to the joint that are angled to intersect the crack near the midpoint of the structure. The construction joints will be injected with a hydro active chemical grout to stop the leak.

This modification / repair should be allowed because:

The probability of occurrence of an accident or equipment malfunction are not increased. Repair of the leaking building expansion joint and concrete construction joints have no effect on the probability of a LOCA, MSLB or earthquake occurring. The probability of malfunction of safety equipment due to ground water intrusion flooding in the Auxiliary Building has not increased since the charging pump cubicle blocks are conservatively sealed to a minimum of 44" above the floor at elevation 244'-6".

The consequences of an accident or equipment malfunction are not increased since leaktight integrity of the containment will be maintained. Sealing the expansion joints between the containment and adjacent building structure that house safe shutdown equipment is designed to accommodate movements of containment associated with LOCA/MSLB internal pressure and differential building seismic displacements. Adequate compressible material will be installed in the building expansion joints to meet original design basis and prevent the space from inadvertently filling with non compressible material or debris. Structural integrity of safety-related and seismic buildings is therefore maintained.

The possibility for an accident or equipment malfunction of a different type than was previously evaluated cannot be attributed to the inspection and repair of leaking expansion joints and concrete construction joints. The expansions joints provide an opening between building interior fire areas and backfilled building exterior. Since there are no below grade fire hazards, there is no possibility for the passage or spread of heat or flame from one fire area to another. Drilling of small diameter holes for grout injection at construction joints will not compromise integrity of the massive concrete structures since no rebar will be cut without prior Engineering evaluation and approval. The expansion joint repair will utilize a compressible chemical grout foam that will maintain seismic independence of adjacent concrete structures.

The implementation of this DCP is not described and therefore will not reduce the margin of safety as defined in the basis of any Technical Specification.

VIRGINIA POWER

VPAP-3001 GOV 02

| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| 95-SE-MOD-80, Rev.3 | [x] North Anna Power Station<br>[ ] Surry Power Station | [x] Unit 1 [x] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**PART A - Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.

DCP-95-015, REA No.95-404

5. Summarize the change, test, or experiment evaluated.
Service Water (SW) pump 2-SW-P-1A is currently in the Alert range for vibration based on results of recent periodic test 2-PT-75.2A. This pump was in the Alert range twice in the last two years. The pump also shows 20 ft of head degradation since 1989. Other SW pumps are also experiencing degradation, although not as severe as pump 2-SW-P-1A. All four pumps are beyond the RCM recommended 10 year interval for tear down and inspection. DCP-95-015 is an evaluation and guideline for one at a time replacement of the existing SW pumps with the new ones which are similar but not exact replacement-in-kind of the existing ones (stainless steel impeller instead of bronze impeller, slightly different pump performance).

6. State the purpose for this change, test, or experiment.
Purpose of DCP-95-015 is an evaluation and guideline for one at a time replacement of the existing SW pumps with the new ones which are similar but not exact replacement-in-kind of the existing ones (stainless steel impeller instead of bronze impeller, slightly different pump performance). Note, that this revision of the SE is issued to incorporate changes which were done due to final issue (Rev.1) of JCO-95-03 and to reflect possibility of installation of alternate support of the SW pump column.

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met.
Since one at a time replacement of the SW pumps requires more than 72 hours, entering TS Section 3/4.7.4.1.a will be required for the each pump replacement. Three other pumps should be operable during this replacement. SW pump replacement will require temporary removal of removable blocks on the SW pump house roof, i.e. missile protection barrier will be partially removed. Removal of the blocks will be guided by station procedures 0-AP-41, Operations Standard 007 and 0-MCM-1304-01. Note, that in accordance with the latest revision of JCO-95-03 (Rev.1 dated 02-06-96) all required limitations including requirements of Standing Order No 213 have been incorporated into corresponding documentation, so standing order No.213 and the JCO have been closed on 03-18-96.

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [x] No

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

Service Water (SW) pump 2-SW-P-1A is currently in the Alert range for vibration based on results of recent periodic test 2-PT-75.2A. This pump was in the Alert range twice in the last two years. The pump also shows 20 ft of head degradation since 1989. Other SW pumps are also experiencing degradation, although not as severe as pump 2-SW-P-1A. All four pumps are beyond the RCM recommended 10 year interval for tear down and inspection. DCP-95-015 is an evaluation and guideline for one at a time replacement of the existing SW pumps with the new ones which are similar but not exact replacement-in-kind of the existing ones (stainless steel impeller instead of bronze impeller, slightly different pump performance). Note, that this revision of the SE is issued to incorporate changes which were done due to final issue (Rev.1) of JCO-95-03 and to reflect possibility of installation of alternate support of the SW pump column.

This DC does not involve an unreviewed safety question:

Three out of four SW pumps and two SW headers will be available during the pump replacement (the pumps will be replaced one at a time). With one SW pump inoperable during the pump replacement, Action Statement per TS Section 3/4.7.4.1.a will be entered, and flow of SW to CCHXs will be throttled to ensure sufficient SW flow to the RSHXs of the accident Unit in the event of a DBA.

The following malfunctions of equipment related to safety were previously evaluated in the UFSAR:
Failure of operating SW pump and rupture of the main SW header.
In case of failure of the operating SW pump during the accident, two remaining pumps will deliver sufficient flow for the Unit safe shutdown. If one out of three operable SW pumps fails during Units' normal operation, AS per TS Section 3/4.7.4.1.b will be implemented. In this case the failed pump should be restored to operable status within 72 hours or both Units should be in HOT STANDBY within the next 6 hours and in cold shutdown within the following 30 hours. In case of rupture of the main SW header, all components will be connected to the remaining operable header.

Replacement of the SW pumps will be done one at a time while the other three pumps are operable. The new pumps will be installed in place of the existing ones. During the replacement pump installation, the corresponding removable block on the pump house roof will be removed. This creates a temporary opening in the missile barrier. Should a severe weather warning occur during this time, Severe Weather Condition Procedure 0-AP-41, procedure 0-MCM-1304-01 and Operations Standard 007 will be adhered to, i.e. the work will be stopped and removed block will be reinstalled. Therefore, the possibility for an accident of a different type than was previously evaluated in the Safety Analysis Report will not be created.

Replacement of the SW pumps will be done within the existing TS (Section 3/7.4.1.a). Therefore, no margin of any TS as described in the basis section will be reduced.
The new pump total developed head (TDH) will exceed the TDH of the replaced deteriorated pumps and the required TDH of original pump Specification NAS-98. Therefore, replacement of the deteriorated SW pumps with the new ones will improve performance characteristics of the SW system and associated systems (CC, RS, etc.).
An NPSH required test for the replacement pump (this test was performed on pump which is in-kind replacement of the existing pump) was conducted by Johnston Pumps on November 9, 1995. As a result of the test evaluation, Deviation Report No. N-95-1829 and Standing Order No. 213, Rev.0 has been issued to direct operations to implement isolation of two RSHXs after one hour but no longer than two hours after the SI/CDA initiation. The RSHXs which are secured shall be one RSHX associated with one inside RS pump and one RSHX associated with one outside RS pump, if possible, to maintain a full coverage spray pattern. Since initial issue of JCO 95-03, investigation was completed on required compensatory actions per this JCO. Calculations were performed for evaluation of summer mode of operation, strong/week pump interaction, two pump operation with throttling CCHXs and isolation of two RSHXs after the containment depressurization. Results of this investigation were the basis for revision of the JCO which was approved on 02-06-96 (Rev.1 of the JCO). In accordance with the recommendations of Rev. 1 of the JCO, requirements of Standing Order No.213 were incorporated into the station operating procedures on permanent basis. This will enhance SW system performance and eliminate unnecessary SW pump high flow operation. For detailed scope of recommendations for various modes of SW system operations see JCO 95-03, Rev.1 (Ref. 6.10).
Since all required compensatory actions of JCO 95-03 were implemented, the JCO was closed out on 03-18-96.
New pumps will be manufactured with interchanging of the first and second stage impellers. NPSH test of this pump proved that the required NPSH is below than available NPSH of 36.9'. New pump performance test showed better than specified pump performance. Therefore, no problems with the NPSH or other performance related problems will be observed.

VIRGINIA POWER

# Safety Evaluation


VPAP-3001 GOV 02

| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| 95-SE-MOD-83 | [ x ] North Anna Power Station<br>[ ] Surry Power Station | [ X ] Unit 1 [ x ] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**PART A - Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.

DCP 94-271

5. Summarize the change, test, or experiment evaluated.

This DCP changes the function of twenty-six (26) fire dampers which are no longer part of fire area boundaries. These dampers will be modified to be nonfunctional and have new mark number labels installed. Ductwork for seven (7) dampers will be modified to allow access for functional testing as recommended by NFPA. Procedures for periodic inspection and functional testing will be modified accordingly.

6. State the purpose for this change, test, or experiment.

Existing station fire dampers need to be relabeled to reflect disabling twenty-six (26) dampers and seven (7) fire dampers require larger or additional access openings to facilitate functional testing. This design change performs the mark number changes for twenty-six (26) dampers which are modified to be nonfunctional and implements ductwork modifications to provide sufficient access to perform the four (4) year functional test of fire dampers as recommended by NFPA.

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met.

None - Implementation of this modification will be performed within the limitations of existing Technical Specifications. The Battery Room and Battery Room door activities are covered by T.S. 3/4.7.7.1 and 3/4.8.2.3. Safeguards Building Ventilation System activities are covered by 3/4.7.8(Exhaust Ventilation will be flow tested prior to return to service). Fuel Building activities are covered by T.S. 3/4.9.12. Control Room habitability is also covered in UFSAR Section 6.4. Maintenance procedures for implementation will have applicable LCO's incorporated.

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [X] No

**Part A - Resolution Summary Report**

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

The major issues considered in this design change are the ability to functionally test the fire dampers as recommended by the National Fire Protection Association (NFPA). Additionally, conformance with the Appendix R fire area boundaries and the operation of the ventilation systems was considered.

Access plates installed or modified in ductwork adjacent to seven (7) fire dampers will allow functional testing as recommended by NFPA. Twenty-six (26) of the existing station fire dampers are not part of the Appendix R fire area boundaries and will be modified to make them nonfunctional. Mark numbers for these dampers will be changed and the fusible links disabled or damper internals removed to preclude spurious closure. Installation of this design change does not alter the design or operation of the associated ventilation systems.

Implementation of this modification will be performed within the limitations of existing Technical Specifications. The Battery Room and Battery Room door activities are covered by T.S. 3/4.7.7.1 and 3/4.8.2.3. Safeguards Building Ventilation System activities are covered by 3/4.7.8. Fuel Building activities are covered by T.S. 3/4.9.12. Separate maintenance procedures for each damper modification are being written which incorporates the appropriate Technical Specification Limiting Condition for Operation.

Modification to the fire dampers or adjacent ductwork does not alter the configuration, design or operation of the associated ventilation systems. Additionally, the Safeguards Area Exhaust Ventilation System will be flow tested prior to return to service to ensure compliance with Technical Specification requirements. Therefore, an unreviewed safety question is not created.

| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| 96-SE-MOD-06 | [X] North Anna Power Station<br>[ ] Surry Power Station | [X] Unit 1 [X] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

PART A - Resolution Summary Report

4. List the governing documents for which this safety evaluation was performed.

DCP 95-221 (unit 1) and DCP 95-242 (unit 2), Removal of Containment Concrete Floor Plugs

5. Summarize the change, test, or experiment evaluated.

Removal of all 22 concrete floor plugs at containment elevation 291'-10" and replacement with flush mounted grating plugs.

6. State the purpose for this change, test, or experiment.

Removal of containment floor plugs at containment elevation 291'-10" will eliminate the need to perform extensive repositioning of the floor blocks at the beginning and end of each refueling outage. The floor plugs are required to be removed from the floor opening during normal operation to provide pressure relief and ventilation space. The concrete floor plugs are inserted into the floor openings for laydown space during refueling outages.

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met.

None

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [X] No

**Part A - Resolution Summary Report**

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

A containment sensitivity analysis has been performed per SWEC calculation 01040.7910-US(B)-278, Rev. 1 to evaluate the impact of the following key changes:

1) Removal of concrete floor plugs
2) Reduced casing cooling available volume to 100,000 gallons
3) Reduced casing cooling pump flow to 600 gpm
4) Increased RMT time from 4 min to 5 min
5) Applied TS uncertainties to IRS/ORS timer delays
6) Use TS Hi Hi CLS pressure setpoint of 30 psia
7) Increased casing cooling water temperature to 55°F for the ORS pump NPSH sensitivity

A full discussion of the parameter changes is provided in Safety Evaluation 95-SE-OT-43. This Safety Evaluation focuses primarily on the potential effects of concrete floor plug removal.

Removal from containment of all 22 concrete floor plugs on containment floor elevation 291'-10" results in a reduction of passive heat sink area and a corresponding increase in the free air volume of containment. The sensitivity analysis conservatively assumed a 5% decrease in the passive heat sink area in containment. The free air volume of containment was conservative increased 0.5%. Removal of passive heat sink area has the potential to increase containment temperature and peak containment pressure during a Design Basis Accident. The increase in free air volume is conservative for peak containment pressure but is slightly nonconservative for ORS and LHSI pump NPSH. Results of SWEC calculation 01040.7910-US(B)-278, Rev. 1 indicate that the removal of 5% passive heat sink area does not compromise the containment design parameters acceptance criteria. In addition, the small increase in containment free air volume resulting in slightly lower containment pressure was judged to have a negligible effect on pump NPSH.

Replacement of the concrete floor plugs with removable flush mounted grating satisfies seismic design requirements. The flush mounted grating is seismically restrained in the lateral direction by sitting recessed within the floor opening. The grating plug bears on a reinforced concrete ledge. Due to low OBE/DBE vertical seismic accelerations for 5% damping at elevation 291'-10", no vertical upward restraint of the grating plug is required. The grating is qualified by Calculation DO-0219 for a uniform live load capacity of 125 psf or a concentrated live load capacity of 1,000 lbs.

The flush mounted grating plugs associated with the three largest openings (containment dome recirculation fan openings) are considered Heavy Loads in accordance with NUREG-0612. Movement of these flush mounted grating plugs will be controlled by procedure 0-MCM-1303-01 to assure compliance with Station commitments to NUREG-0612.

In conclusion, this change does not constitute an unreviewed safety question because:

1) No increase in the probability of occurrence or consequence of an accident or malfunction of equipment will result from the removal of concrete plugs from containment. There are no changes to plant systems or components required to mitigate a design basis accident associated with removal of concrete floor plugs from containment. The consequences of an accident remain within the design acceptance criteria for containment parameters.

2) The removal of concrete floor plugs from containment and the installation of flush mounted grating plugs does not create the possibility of an accident or malfunction of equipment of a different type than any which have been evaluated previously in the Safety Analysis Report. No new or unique accident precursors have been introduced.

3) The margin of safety as defined in the basis of the Technical Specifications is not reduced by implementation of this change. The Technical Specifications ensure that the plant conditions will be such that containment integrity will not be challenged. Analysis has shown that the acceptance criteria for the most limiting containment accident will not be exceeded.

VIRGINIA POWER

DCP # 94-010, FC#1

APPENDIX 4-15



**Safety Evaluation**


VPAP-3001 GOV 02

| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| 96-SE-MOD-20 | [x ] North Anna Power Station<br>[ ] Surry Power Station | [x ] Unit 1 [x ] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**PART A - Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.

DCP-94-010, FC#1

5. Summarize the change, test, or experiment evaluated.

Installation of Calgon's permanent biofilm sampling device (BSD) is planned in the SW valve house. The installation will include two 1" branches from SW lines 18"-WS-D83-151-Q3 and 24"-WS-D88-151-Q3 upstream of valves 1-SW-MOV-122B and 2-SW-MOV-222B. Two SR one inch diameter lines with valves will be connected together downstream of the valves and the 1" line will go to the NSQ seismic metal box (compartment) where the sampling device is installed. The NS, non-seismic BSD consists of 1/2" piping, 1/2" ball valves and replaceable samples located inside the sampling cylinder. To eliminate adverse effects of the device's failure, the box is drained to the reservoir. Two inch drain line is calculated to remove water from the box without overflow in case of failure of the 1/2" piping within the box.

6. State the purpose for this change, test, or experiment.

The purpose of the BSD installation is to analyze the effectiveness of the SW chemical treatment.

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met.

Connections of the 1" lines to discharge SW headers 18"-WS-D83-151-Q3 and 24"-WS-D88-151-Q3 require isolation of the main SW headers. Per DCP-94-010 each main SW header will be isolated three times. Therefore, the one inch connection to the BSD will be installed during main SW header isolation for the SW lines replacement to/from CCHXs.

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [x] No

Part A - [illegible]

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

Installation of Calgon's permanent biofilm sampling device (BSD) is planned in the SW valve house. The installation will include two 1" diameter branches from SW lines 18"-WS-DB3-151-Q3 and 24"-WS-DBB-151-Q3 upstream of valves 1-SW-MOV-122B and 2-SW-MOV-222B. Two SR one inch lines with valves will be connected together downstream of these valves and the 1" line will go to the NSQ seismic metal box (compartment) where the sampling device is installed. The NS, non-seismic BSD consists of 1/2" piping, 1/2" ball valves and replaceable samples located inside the sampling cylinder. To eliminate adverse effects of the device's failure, the box is drained to the reservoir. The two inch drain line is calculated to remove water from the box without its overflow in case of failure of the 1/2" piping within the box. The purpose of the BSD installation is to analyze effectiveness of the SW chemical treatment.

This FC does not involve an unreviewed safety question:

The BSD installation does not affect the design/operation/configuration of the SW system or any other system. The TS are also not affected. A small amount of the SW (approximately 6 gpm) will be diverted to the BSD and discharged in the spray pond bypassing the spray arrays. It will not effect the spray pond performance considering large spray pond volume and normal SW flow rate of approximately 23,000 gpm.

Connection of the BSD requires isolation of the main SW headers. The main task of DCP-94-010, Repair/Replacement of Exposed SW Piping to/from CCHXs, requires the isolation of the main SW headers (three separate isolations for each header for total of six isolations). Two out of six 168 hour TS Section 3/4.7.4.1.d AS on the SW headers will be utilized for the connection of 1" SR piping for the BSD connection to SW discharge headers 18"-WS-DB3-151-Q3 and 24"-WS-DBB-151-Q3. Therefore, the BSD connection to the SW headers is enveloped by the main task of DCP-94-010 and its SE (95-SE-OT-04) and it does not increase the probability of occurrence for the accident previously evaluated in the Safety Analysis Report.

VIRGINIA POWER



VPAP-3001 GOV 02

| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| 96-SE-MOD-23 | [X] North Anna Power Station<br>[ ] Surry Power Station | [ ] Unit 1 [X] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**PART A - Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.

DCP 95-190

5. Summarize the change, test, or experiment evaluated.

A diaphragm plate is to be welded to the flange of the casing cooling tank (CCT) and refueling water storage tank (RWST) lower manways. A new manway cover is to be fabricated for the RWST and the manway covers will be reinstalled to provide backing for the plates.

6. State the purpose for this change, test, or experiment.

The lower manways on the unit 2 CCT and RWST have experienced leakage. The water in the tanks is borated and may be contaminated and any leakage is undesirable. The tanks are difficult to drain for repairs so the manways will be permanently sealed to prevent possible leakage in the future.

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met.

None

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [X] No

**Part A - [illegible]**

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

The unit 2 RWST and CCT have had problems with leakage at the lower manways. The tanks are difficult to drain for repair of the leaks due to the Technical Specification requirements for the tanks and the difficulty storing the borated water. The tanks will be drained and a diaphragm plate is to be welded to the lower manways. A new manway cover is to be fabricated for the RWST to remove the raised face of the cover. The manway covers shall be reinstalled to provide backing to the diaphragms so that tank integrity is not affected. The design, function and operation of the tanks are not affected by this change.

The applicable action for fire protection shall be taken as required per the Technical Requirements Manual while the RWST inventory is less than 51,000 gallons.

The accidents which are applicable to this change are LOCA and main steam line break. Applicable malfunctions are failure of the related pumps (LHSI, HHSI, quench spray and casing cooling) and piping.

UNREVIEWED SAFETY QUESTION ASSESSMENT

1) Accident probability will not be increased as both the RWST and CCT are used for accident mitigation only.

2) Accident consequences are not affected. The diaphragm plates are being installed to prevent leakage and will not affect Technical Specification requirements for the tanks. The pressure boundary will be maintained by the blind flange.

3) No unique accident possibilities are created. The RWST and CCT are only used in the event of an accident. The diaphragm plates will prevent any leakage from the tanks but will not affect the operation of either the quench spray or recirc spray systems.

4) Margin of Safety is maintained because the operation of the tanks and the quench spray and recirc spray systems is not affected. Technical Specification requirements for the tanks and systems will not be affected.

APPENDIX 4-1

VIRGINIA POWER



| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| 96-SE-MOD-33, Rev. 1 | [ x ] North Anna Power Station<br>[ ] Surry Power Station | [ ] Unit 1 [ x ] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**PART A - Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.

DCP 95-002

5. Summarize the change, test, or experiment evaluated.

This DCP will install new condensate polishing filters, filter to tube sheet locking hardware, upper vessel filter retention hardware and a draft distribution tube in condensate polishing vessels 2-CP-FD-1A/1B/1C/1D/1E.

6. State the purpose for this change, test, or experiment.

This design change will provide operational flexibility for condensate vessels 2-CP-FD-1A/1B/1C/1D/1E. The new filter elements can function as a precoated resin filter and, after backwashing the resin from the elements, the filters can function as a mechanical filter for the removal of suspended solids (i.e. iron). The purpose of this design change is also to test/evaluate the performance of the new elements in the filtration and ion exchange mode of operation. 1

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met.

The Condensate Polishing System will be out of service during the modification work of this design change. Testing of the new filters will be accomplished with the CP system in service. The new filters and hardware will meet the design requirements of the Condensate Polishing System.

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [x] No

**Part A - Resolution Summary Report**

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

The Condensate Polishing (CP) System is a non-safety system. The system was originally designed to operate at 100% condensate flow. The CP System currently operates, only as required, for the removal of impurities in the condensate by using a precoat of resin on the filter elements. The method of attachment of the filter elements to the tube sheet has been suspect in past resin intrusion events. For example, it has been postulated that during pressure transients (i.e. the starting of a third condensate pump), the 80 inch elements have the potential to flex and cause the base of the elements to deflect and permit resin to slip by into the condensate stream. The existing filter elements (except for the Unit #2 "B" and "D" vessels) utilize a spring and latch mechanism for the retention of the filter element to the tube sheet. This potential instability of the filter elements lead to the reduce operational use of the system because of the concern for slipping resin to the steam generators. It should be noted that the Unit #2 "B" and "D" vessels have not been identified as causing any resin slippage problems. Unit #2 "B" and "D" vessel already are utilizing an early version of the Sealfast locking hardware which will be installed in all of the vessels. In addition, because of the use of the existing lift plates for retention and spacing of the top part of the filter element, there was inefficient use of precoat resin due to some of the resin being deposited on top of the lift plates as opposed to the surface of the filter elements.

This design change will provide operational flexibility for all of the condensate polishing vessels, 2-CP-FD-1A/1B/1C/D/1E. The new filters, AFA Dual Guard, are supplied by Graver Chemical. The new filter elements can function as a precoated resin filter and, after backwashing the resin from the elements, the filters can function as a mechanical filter for the removal of suspended solids (i.e. iron). The backflush protocol will be the same for both the precoated and non-precoated filter elements. A flow distribution tube and an improved open lattice design at the top of the filter elements will allow improved vessel hydraulics and increase resin efficiency (less resin not applied to the filters). Therefore, the new filter elements and associated hardware will maintain the designed secondary water chemistry and will reduce the potential for damage to the steam generator tubes by the intrusion of resin into the condensate stream.

In summary, it is concluded that the above mentioned non-safety related modification to condensate vessels 2-CP-FD-1A/1B/1C/1D/1E will not result in an unreviewed safety question because:

1) This modification does not adversely affect the operation of non-safety related Condensate Polishing System. The design change does not increase the probability of occurrence or increase the consequences for the accidents previously evaluated in the SAR or create the possibility for an accident of a different type.

2) This modification does not increase the probability of occurrence or consequence of malfunctions of equipment previously identified in the SAR or does it create the possibility for a malfunction of equipment of a different type than was previously evaluated in the SAR.

3) The modification has not reduced the margin of safety of any part of the Technical Specifications as described in the bases section.

VIRGINIA POWER



VPAP-3001 GOV 02

| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| 96-SE-MOD-034 | [XX] North Anna Power Station<br>[ ] Surry Power Station | [XX] Unit 1 [XX] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**PART A - Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.

DCP 95-127, DCP 95-216

5. Summarize the change, test, or experiment evaluated.

- Carbon/stainless steel cladded charging pump casing replaced with SA-182 F304 SS (1-CH-P-1B & 1-CH-P-1C).
- A-266 carbon steel discharge head replaced with a SA-182 F304 SS head (1-CH-P-1B,1C & 2-CH-P-1A,1B,1C)
- A276 Type 410 SS seal housings replaced with SA-182 F304 SS housings (1-CH-P-1B,1C & 2-CH-P-1A,1B,1C).
- A276 Type 410 SS alloy seal plates retained for use on new seal housings (1-CH-P-1B,1C & 2-CH-P-1A,1B,1C).
- Installation of additional seal retainer plate (1-CH-P-1A,1B,1C & 2-CH-P-1A,1B,1C).
- Removal of existing seal coolers (1-CH-P-1A,1B,1C & 2-CH-P-1A,1B,1C).
- Relocation of the cradle boss and keyway as required to ensure correct pump/driver alignment. Minor modifications as required for the casing mounting feet (1-CH-P-1B & 1C).

6. State the purpose for this change, test, or experiment.

Previous inspections of the carbon steel charging pump casings discovered indications which warranted pump casing replacement. In lieu of further inspections, the casings will be replaced for the remaining carbon steel pump casings associated with 1-CH-P-1B & 1C. Replacement of the discharge head and seal housings is required to eliminate the stress that could be created by using different materials with different thermal expansion properties. Re-use of the existing Type 410 seal plates is an acceptable alternative to installing new plates without compromising pump operability. Addition of seal retainer plate will allow even loading of the seal unit. Installation of the new seal housings will allow removal of the seal coolers since they will not be required for the upgraded seal housing.

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met.

None

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [X] No

**Part A - Resolution Summary Report**

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

The charging pump manufacturer had previously issued a bulletin advising owners of the pumps that had casings constructed of carbon steel cladded with stainless steel to inspect them for cladding cracks, erosion or damage when disassembled. Past inspections of the carbon steel charging pump casings at NAPS discovered indications which were severe enough to warrant casing replacement rather than repair the existing casing. The existing pump casings for 1-CH-P-1A, 2-CH-P-1A,1B &1C were replaced with solid stainless steel casings.

Due to the failure rate exhibited by previous inspections, the carbon steel pump casing associated with 1-CH-P-1B & 1C will be replaced. The replacement stainless steel casings are supplied by the original pump manufacturer, Ingersoll-Dresser Pump Company (Pacific Pumps). The replacement pump casing is superior to the original due to improved corrosion resistance. The new casing meets or exceeds all design requirements for the original equipment. All nozzles and connections on the new casing are of the same size and location, so no piping changes are required. The pump internals, which determine the pump's performance characteristics, are reinstalled in the new casing to avoid generating changes to the pumps pressure and flow features. Minor changes to the pump mounting have been reviewed and approved by the pump vendor.

Previous casing replacements for the Unit 2 charging pumps did not include replacement of the A-266 carbon steel discharge heads or the A-276 Type 410 seal housings. As documented in Deviation Report N-95-1070, the difference in thermal expansion between these components and the pump casing had the potential to produce bending stresses in the discharge head and seal housing bolting which cause the combined stresses to exceed code allowable values. Replacement of the discharge head and seal housings with those constructed of SA-182 F304 SS is required to maintain or restore the pump design to an acceptable configuration and limit the stress within the basic allowable value. Replacement of the pump components will not impact the operation or performance of the charging pumps.

Installation of upgraded 2nd generation seal housings eliminate the need for external seal flush piping and associated heat exchangers. The seal coolers from both Unit 1 & 2 charging pumps will be removed and the service water lines to the coolers will be capped. No adverse affects on the SW system will result from this change. Existing A-276 Type 410 seal plates will be re-used on the new seals housings since it has been determined that the difference in materials between the plate and housing will not compromise pump operability.

SUMMARY OF SAFETY ANALYSIS

The replacement of the charging pump casing did not constitute an unreviewed safety question as defined in 10CFR50.59 since it did not:

A) Increase the probability of occurrence or the consequences of an accident or malfunction of equipment important to safety and previously evaluated in UFSAR.

The activity will replace the remaining carbon steel, cladded with stainless charging pump casings for 1-CH-P-1B & 1C with a SS casing that meets or exceeds the design requirements of the original equipment. Replacement of the discharge head and seal housings with those constructed of the same material (304 SS) as the pump casing is required to eliminate undesired stresses caused by differential thermal expansion. Minor modifications to the pump mounting will not affect the operability or performance capability of the pump. Pump reliability is increased by the modification. The operational characteristics of the pump remain the same since the pump internals will be retained for use in the new casing. Replacement of the other charging pump components will not affect pump operability. The HHSI/charging pump will continue to perform it's intended function for mitigation of applicable accidents.

B) Create a possibility for an accident or malfunction of a different type than any evaluated previously in the UFSAR.

Pump casing and component replacements are essentially a one-for-one replacements which upgrade the pump design. All modifications involved with the charging pump components will in no way affect pump performance or operation. Upgraded seal housings eliminate the need for external seal coolers and thus improve pump reliability. The new components have the same form, fit and function as the old parts. The pump will continue to operate in the same manner as before this modification is performed. The possibility of generating a different type of accident or malfunction than previously evaluated is not credible.

C) Reduce the margin of safety as defined in the basis of any Technical Specification.

Pump component replacement and seal cooler elimination will not have any adverse impact on the Tech Specs associated with the charging pump nor will any margin of safety be affected by this modification. Pump operation remains unchanged as a result of the design change.

VPAP-3001 GOV 02

[redacted]

| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| 97-SE-MOD-34, Rev.1 | [x ] North Anna Power Station<br>[ ] Surry Power Station | [ ] Unit 1 [x ] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**PART A - Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.
DCP 97-003, Replacement of CCHXs, North Anna, Unit 2

5. Summarize the change, test, or experiment evaluated.
CCHXs have experienced tube leakage due to microbiologically influenced pitting corrosion. Leaking tubes have been plugged, but a significant number of tubes exhibit evidence of pitting corrosion and could develop leaks in the future. Calculation ME-0530, Rev.0 established the limit (22%) of tubes which can be plugged without adversely effecting CC system performance and up to 30% of tubes if SW temperature is limited to 85°F. Since plugging of the tubes is approaching the above limits, it was decided to retube Unit 1 CCHXs and replace Unit 2 CCHXs. Unit 2 CCHXs will be replaced utilizing high corrosion resistance material (Titanium) for tubes and other parts of the HX which contact SW.

6. State the purpose for this change, test, or experiment.
The purpose of DCP 97-003 is to restore original capacity of Unit 2 CCHXs by replacing them utilizing corrosion resistant material (Titanium) tubes.

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that those conditions and/or requirements will be met.

See page 1A.

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [x] No

Part A [illegible]

Item 7

1. The replacement will be done under LCOs per TS Section 3.7.3.1. One CCHX will be replaced at a time; therefore, no TS AS is required if three other CCHXs are operable.
2. Limiting conditions per JCO C-96-04, JCO C-97-01 and Standing Order No.221 are applied during the replacement.

Note:
Item 2 above will not be applicable after Unit 1 CCHXs are retubed, one out of two Unit 2 CCHX is replaced and second Unit 2 CCHX is isolated for replacement, i.e. when two retubed and one replaced CCHX are operating and fourth CCHX is isolated for replacement. Also, limiting conditions of SE 94-SE-OT-034 of JCO C-96-04 and JCO C-97-01 will not be applicable when all four CCHX are retubed/replaced, i.e. regardless which three out of four CCHXs are operating or all four are operating.

3. Removal of blocks in the roof of the Auxiliary Building above upper channel of the heat exchanger will be guided by 0-AP-41, Operations Standard 007, 0-MCM-1304-01 and special rigging procedure developed for this DCP.

4. All Unit 2 charging pumps and all four CC pumps shall be operable prior to removing 30" elbow from CC discharge nozzle of heat exchanger 2-CC-E-1A.

Rev. 1 (Item 4 was Removed)

The following LCOs per NAPS TRM will be observed during implementation of Unit 2 CCHX replacement (for details see response to item 44D):

1. Appendix R supply duct (ducts from fans 1-HV-F-75A and 75B) will be temporarily dismantled from elevation 286' (below Auxiliary Building roof) to approximately elevation 270', see drawings N-97003-2-1FB11A, 11C, 11F, 11U. Also, the suction bell on fan 1-HV-F-75B will be temporarily removed. After demolishing of the existing heat exchangers and installation of new ones, the ducts will be restored to their original configuration.
In accordance with section 7.5, page 7-36 of NAPS TRM, hourly fire watch in the affected areas shall be implemented within 14 days and duct restoration shall be done within 60 days (Condition A). It is expected that ducts will be restored within requirements of Condition A. Corresponding Action Statement will be entered by operations per DCP requirements.

2. For relocation of FP water lines inside the Auxiliary Building FP water supply will be interrupted for approximately 20-24 hours (valves 2-FP-88 and 2-FP-24 will be closed, ref. drawing 12050-FB-104A). Action Statement per Section 7.1.5, page 7-12 of NAPS TRM will be entered. As a contingency measure temperature will be monitored within the Reactor Containment Unit 1 and Unit 2 and fire watch will be established in the Auxiliary Building. Temporary fire hoses will be staged to the containment personnel hatches and entrances of the Auxiliary Building. The hoses will be staged within one hour or prior to the piping isolation per DCP requirements.

3. For inoperable sprinklers within the Auxiliary Building Action Statement per Section 7.1.7, page 7-19, Condition A will be entered per DCP requirements.

4. Low pressure $CO_2$ line at elevation 291'-10" will be permanently relocated closer to wall to accommodate the CCHX replacement (drawing N-97003-2-1FB10C). The relocation will take approximately 24 hours. Action Statement per Section 7.1.2, Condition A will be entered per DCP requirements.

**Part A - Resolution Summary Report**

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

CCHXs have experienced tube leakage due to microbiologically influenced pitting corrosion. Leaking tubes have been plugged, but a significant number of tubes exhibit evidence of pitting corrosion and could develop leaks in the future. The purpose of DCP 97-003 is to restore original capacity of Unit 2 CCHXs by replacing them utilizing corrosion resistant titanium tubes.

The replacement does not involve an unreviewed safety question:

The CC water system (CCWS) is an intermediate cooling system which transfers heat from heat exchangers containing reactor coolant or other radioactive liquids to the SW system. The design basis of the CCWS is a fast cooldown of one unit while maintaining normal loads on the other unit. The CCWS is not a system which functions to mitigate a design basis accident (DBA) or presents a challenge to the integrity of a fission product barrier. Therefore, the probability of occurrence or the consequences of an accident previously analyzed in the UFSAR will not be increased.

CCWS serves no accident mitigation function. Replacement of one CCHXs at a time will leave three CC system operable which is enough for CCWS to perform its design functions. Therefore, consequences of accidents previously analyzed in the UFSAR will not be increased. Replacement of CCHXs will be done within requirements of existing TS Section 3/4.7.3.1.

Replacement CCHXs will be furnished with corrosion resistant welded titanium tubes ASME SB-338 Gr.2 instead of welded stainless steel tubes ASTM-304L in the existing CCHXs. The replacement heat exchangers have been designed for the same heat loads and flow rates as the existing CCHXs, therefore, CCHX thermal and hydraulic performances are not affected by this replacement. Note also, that the new heat exchangers are interchangeable with the existing ones, i.e. all nozzles and supporting interfaces match up with the configuration of the existing heat exchangers. This will minimize the required replacement work. Table 9.2.5 of the UFSAR will be revised to incorporate tube material change. UFSAR Change Request is included in Appendix 1-1 of the DCP. Replacement of CCHXs will increase reliability of the HXs, therefore, it will decrease probability of occurrence of equipment malfunctions (CCHX tube rupture) previously analyzed in the UFSAR.

Lifting and rigging of the new CCHXs and old (existing) ones, concrete blocks above the heat exchangers and other loads in excess of 2000 lbs will be guided by appropriate station procedures and NUREG-0612 "Heavy Loads Program".

Neither the replacement nor the activities required to implement it will create the possibility for a malfunction of equipment of a different type than was previously evaluated in the UFSAR.

One CCHX will be replaced at a time. The replacement will not reduce margin of safety of the CCWS as described in the TS since it does not reduce the number of heat exchangers available to meet design heat transfer requirements per TS Bases Section 3/4.7.3.1 and 3/4.7.3.2.

VPAP-3001 [redacted] GOV 02

| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| 98-SE-MOD-10 | [x] North Anna Power Station<br>[ ] Surry Power Station | [ ] Unit 1 [x] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**PART A - Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.

DCP 97-014 - Outside Recirc Spray Pump Motor Replacement

5. Summarize the change, test, or experiment evaluated.

The existing unit 2 Outside Recirc Spray Pump Motor (2-RS-P-2A-Motor) will be replaced with a motor that is a modern replacement for the existing motor and has the same performance characteristics, but different physical characteristics. The new motor is built on a square frame and some special adjustments will be required to install it in the same location as the existing motor.

6. State the purpose for this change, test, or experiment.

The existing motor has a bent shaft.

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met

This work will be done with the unit off line in mode 5 or 6 (tracked by the Special Implementing Instruction section of the DCP) as required by Tech Specs. A security watch may be required while the overhead block is out of place (informational action item). A severe weather event will require that the overhead block is replaced (informational action item). The Informational Action Items are addressed in the Supplememntal Implementing Information section of the DCP

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [x] No

VPAP-3001 97-014 GOV 02

[redacted]

**Part A - Resolution Summary Report**

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

This project is to replace a motor on the unit 2 Outside Recirculating Spray Pump (2A) due to the existing motor having a damaged shaft. The replacement motor is a modern replacement for the existing motor and is a close match electrically to the existing motor, but modern motors of this size and type are built on square frames. The project involves lifting the vertical shaft motor from its mounting and replacing it with a new motor. The new, square-frame, motor will require some physical adjustments to adjacent seismic supports.

The function of the Recirculating Spray system will not be affected, thus there is no impact on any accident scenario. The system is designed to respond (in conjunction with the quench spray system) to reduce the temperature and pressure inside containment after a LOCA. Changing the motor on one of the pumps with a motor that meets all of the original design requirements does not introduce any new accident type nor does it increase the probability or consequences of any accident already analyzed.

Failure of any motor is already analyzed in the redundancy of trains. A Loss Of Offsite Power is included in the fact that this motor is safety-related and supplied by diesel-backed power. The new motor meets all of the original design requirements for the existing motor and will be just as reliable.

All existing Technical Specification surveillance requirements, Bases descriptions and Margins of Safety are unchanged by this motor replacement. Therefore, this motor replacement should be allowed.

VIRGINIA POWER



VPAP-3001 - Attachment 3

| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| **99-SE-MOD-03** | [x] North Anna Power Station<br>[ ] Surry Power Station | [x] Unit 1 [x] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**Part A – Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.

**DCP 99-124 (Unit 1) and DCP 99-125 (Unit 2) Relocate RS Pump Temporary Test Dike Panel Storage for Installation of Reactor Head Stand Water Shields**

5. Summarize the change, test, or experiment evaluated.

**Stainless steel water shield tanks will be stored inside the reactor head storage stand during the operating cycle. The tanks will be filled with water during a refueling outage to provide radiation shielding for personnel inspecting, removing and replacing the reactor head O-ring seals. The water shield tanks shall be emptied at the end of the outage. Also, RS Pump temporary test dike panels that are currently permitted to be stored in the reactor head stand will be stored in another designated location in the containment basement.**

6. State the purpose for this change, test, or experiment.

**Stainless steel water shield tanks will replace fiberglass water shield barrels that are currently brought into and removed from the containment each outage. Storing the stainless steel water shields inside the reactor head stand will minimize the time spent to install and remove the shielding each outage. Possible damage to the shield containers due to personnel handling required for storage outside containment will be eliminated.**

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met.

**The reactor head stand water shield tanks shall be drained by radiation protection personnel at the end of each outage and the local drain plug/valve left in the open position. These requirements shall be independently verified prior to unit start up by procedure 1/2-OP-1B as applicable.**

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [x] No

**Part A - Resolution Su[illegible] Rep[illegible]**

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

**Stainless steel water shield tanks will be stored inside the reactor head storage stand during the operating cycle. The tanks will be filled with water during a refueling outage to provide radiation shielding for personnel inspecting, removing and replacing the reactor head O-ring seals. The reactor head stand water shield tanks will hold a total of approximately 2,000 gallons of unborated water when filled. Therefore, the water shield tanks shall be emptied at the end of the outage to avoid a possible concern with water leakage from the shield tanks diluting RS sump boron concentration after a LOCA. The design of the tanks will have open vent and drain connections to provide containment pressure equalization and prevent water hold up in the tanks. Recirculation flow paths to the RS sump during design basis accident conditions will not be affected. The open vent and drain connections will allow the shield tanks to fill up with water during a LOCA so that they will not float. The water shield tanks are effectively restrained by the reactor head stand structure to prevent interaction with safety related components during a seismic event.**

**During shutdown operations, when the shield tanks are filled with water, significant damage to the tanks resulting in gross leakage is not considered credible in the event that the RS sump is required for maintain alternate core cooling using Forced Feed and Spill in accordance with 0-GOP-13.0.**

**Also, RS Pump temporary test dike panels that are currently permitted to be stored in the reactor head stand will be stored in another designated location. The RS Pump temporary test dike panels will be stored in the containment basement away from the RS sump in an area that does not have the potential for the dike panels to interact with safety related components during a seismic event.**

**This change does not constitute an unreviewed safety question because:**

1) **No increase in the probability of occurrence or consequence of an accident or malfunction of equipment will Result from the installation of stainless steel water shield tanks inside the reactor head storage stand or by storage of RS Pump temporary test dike panels in containment. The water shield tanks will be drained prior to unit start-up to prevent possible dilution of RS sump boron concentration after a LOCA. The water shield tanks and RS Pump temporary test dike panels are stored in locations where no interaction with safety related Components during a seismic event is possible.**

2) **The installation of stainless steel water shield tanks inside the reactor head storage stand and storage of RS Pump temporary test dike panels in containment does not create the possibility of an accident or malfunction of equipment of a different type than any which have been evaluated previously in the Safety Analysis Report. No new or unique accident precursors have been introduced.**

3) **The margin of safety as defined in the basis of the Technical Specifications is not reduced. Installation of Stainless steel water shield tanks inside the reactor head storage stand and storage of RS Pump temporary test dike panels in containment will not degrade or compromise safety related components required for design basis accident mitigation.**

**99-SE-MOD-05**

**Description**
Inspection ports are to be added for inspection of the service water to RSHX check valves. Each port is to consist of a sockolet and a blind flange with pipe as required.

**Summary**
Inspection ports are to be added to the SW to RSHX lines. The ports are to be used to inspect the SW to RSHX check valves to ensure that they are normally closed. The IST Program requires that the check valves be inspected. Removal of the valves is labor intensive and a visual inspection is an acceptable method of testing. The ports are to include a sockolet, blind flange and a short section of pipe.

Pipe stress and supports were evaluated and found acceptable for all specified loading conditions including seismic.

The accidents considered were those which result in containment depressurization, including LOCA and Main Steam Line Break.

UNREVIEWED SAFETY QUESTION ASSESSMENT

1. Accident probability will not be increased because the recirculation spray heat exchanges are used for accident mitigation only.

2. Accident consequences are not affected. The inspection ports are required to ensure that the check valves are closed. A check valve stuck in the open position could divert water from the RSHX. The resultant flow would still meet system design requirements, per calculation ME-0547, but to maintain margin of flow available the check valves are to be inspected. System leakage, should a port fail, would be bound by this calculation.

3. No unique accident possibilities are created. The inspection ports are basically passive components which will only be used when the unit is shutdown. The service water lines affected are only used after a DBA. System design bases are unchanged.

Margin of Safety is maintained because the integrity and reliability of the system are not affected. The margins of safety as described in the bases of the Technical Specifications are not affected.

| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| 99 - SE - MOD - 06 | [X] North Anna Power Station<br>[ ] Surry Power Station | [X] Unit 1 [X] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**Part A - Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.
DCP 99-106 "SECURITY SYSTEM MAGNETIC DOOR LOCK ENHANCEMENTS"

5. Summarize the change, test, or experiment evaluated.

This DCP replaces access control devices (electric strikes) with magnetic door locks, and removes the existing security latchsets for Emergency Switchgear Room door (02-BLD-STR-S54-11-ACCESS), Chiller Room to Turbine Area Doors (01-BLD-STR-S54-1-ACCESS, 02-BLD-STR-S54-14-ACCESS). Magnetic door lock assemblies will be added to Main Control Room doors (01-BLD-STR-S76-26-ACCESS & 02-BLD-STR-S76-25-ACCESS), EDG to Turbine Area doors (01-BLD-STR-S71- 17 & 19-ACCESS, 02-BLD-STR-S71-16 & 18-ACCESS), New Fuel Recovery door (01-BLD-DR-F72-1-ACCESS), Fuel Building to Auxiliary Building door (01-BLD-DR-F91-1-ACCESS) and Security Inverter Room door (01-BLD-DR-CC71-3-ACCESS) to supplement the existing security electric strikes. Magnetic door lock assemblies will replace the security electric strikes on Rod Control doors (01-BLD-DR-M80-1-ACCESS and 02-BLD-DR-M80-2-ACCESS), Quench Spray Pump House doors (01-BLD-DR-QS72-1-ACCESS & 02-BLD-DR-QS72-3-ACCESS), and Main Steam Valve House doors (01-BLD-DR-MS72-1-ACCESS & 02-BLD-DR-MS72-2-ACCESS).

6. State the purpose for this change, test, or experiment.

The purpose of this design change is to still provide security against sabotage and resolve multiple door latch problems for the doors referenced in section 5.

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met.
The plant may be in any mode of operation for this design change. Work on doors S54-11, S76-26 & 25 require that the Control Room pressure boundary be breached. This will require entering the action statement of Section 3.7.7.1 of Technical Specifications if the Control Room differential pressure can not be kept within limits while these doors are being worked under this design change. Shift supervisor notification is required by DCP 99-106 Supplemental Implementing Information.

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [X] No

**Part A - Resolution Summary Report**

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

The purpose of this design change is to control access to the Emergency Switchgear Room, Chiller Rooms, Main Control Room, EDG Rooms, Rod Control, MSVH, QSPH, New Fuel Recovery, Fuel Building to Aux. Building and Security Inverter Room doors and resolve multiple door latch problems. These areas will remain security controlled areas where ingress but not egress is controlled and logged. Existing security bypass and emergency egress requirements for the appropriate doors will still be maintained by DCP 99-106.

Operability of the safety-related equipment within the Emergency Switchgear Room, Chiller Rooms, EDG Rooms, Main Control Room, QSPH and MSVH will not be adversely affected by this design change. The security system neither supports nor is supported by any safety–related equipment. The magnetic door locks are powered by sources that are independent of other plant systems. There is no credible mode of failure for the equipment being added by this DCP that would adversely impact any safety-related equipment within the envelope established by the new magnetic door locks. The seismic adequacy of the doors will not be compromised. Rigid mounting of the lock assemblies to the door and the door frame, will ensure that the assemblies will stay secured during a seismic event.

Access to the Emergency Switchgear Room is necessary in cases where the Control Room is no longer habitable. Operators will still have access with their keycards. The security system is both UPS and security diesel power backed and therefore does not depend on any station power system in order to remain operational. It should be noted that the new magnetic door lock will fail safe (unsecured) which does not require the use of a latchset at the top of the door. The latchsets will be removed from the Switchgear Room and Chiller Room doors. Finally, the shortest path to the auxiliary shutdown panels from the Control Room via the back stairwell from the Logic Rooms will remain available as it is now with no new card readers in the path. This design change will not add any security barriers to operators utilizing this path to the Emergency Switchgear Room. Therefore, this design change will not adversely affect operator access to the auxiliary shutdown panels.

Access to and egress from the EDG Rooms will remain unchanged, the installation of a new security key lock switch for each EDG door to defeat the magnetic door lock is not required because another means of access and egress already exists.

Access to Unit 1 Control Room via 01-BLD-STR-S76-26-ACCESS will remain unchanged, the installation of a new security key lock switch to defeat the magnetic door lock will be performed under DCP 99-106. An emergency egress pushbutton will be installed under DCP 99-106 to be used in conjunction with the existing panic bar.

Temporary breaches of EQ and Appendix R fire doors will be compensated by posting the appropriate EQ and fire watches while work is in progress. The watches will be done in accordance with the Technical Requirements Manual and also VPA-2401 for Appendix R and VPAP-0305 for EQ. Compensatory measures have been provided in Sections 3.3, 3.4 and 3.16 of the design change. By utilizing these procedures adequate compensatory measures will be in place so as not to compromise plant safety.

This design change will require that the Control Room pressure boundary be breached while work is in progress. This will make it necessary to enter the action statement of Section 3.7.7.1 of Technical Specifications if the Control Room differential pressure can not be kept within limits. However, the required work will be completed in less time than the 24-hour period of the action statement. Material to temporarily close these breaches in an emergency will be available while work is in progress.

FME concerns for work performed on Fuel Building to Auxiliary Building door (01-BLD-DR-F91-1-ACCESS) will be controlled via "Fuel Building FME Assessment of Maintenance Activities" procedure 0-GOP-4.16 via DCP 99-106.

Therefore, it has been concluded that this design change will not result in any unreviewed safety questions.

VIRGINIA POWER



| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| 99-SE-MOD- 12 | [✓] North Anna Power Station<br>[ ] Surry Power Station | [✓] Unit 1 [✓] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**Part A: Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.

Procedures: 1-OP-32.3, 1-AR-32, 1-ICP-BD-G-001, 2-OP-32.3, 2-AR-32 and 2-ICP-BD-G-001 , 1-MOP-32.4 and 2-MOP-32.4
ET SE 99-034 - Conpensatory measures required for blocking an automatic system trip of the high capacity S/G blowdown system.
Field Change for DCP-98-130: Unit 1 Blow Down System Upgrade
DCP-99-119: Unit 2 Blow Down System Upgrade.

5. Summarize the change, test, or experiment evaluated.

This evaluation assesses the acceptability of individually overriding the following automatic trips for the Unit 1 and 2 High Capacity Steam Generator (SG) Blowdown (BD) System:
1. Blowdown Flash Tank Inlet Flow Trip (1(2)-BD-FT-102 (202) A/B/C), 2. Blowdown Flash Tank High Outlet Flow Trip (1(2)-BD-FT-105 (205)), 3. Blowdown Flash Tank Hi-Hi Pressure Trip (1(2)-BD-PT-100 (200)), 4. Blowdown Flash Tank Level Trip (1(2)-BD-LT-100 (200)), 5. Blowdown Outlet Cooler High Temperature Trip (1(2)-BD-RTD-101 (201)) and 6. Low Condenser Vacuum Trip (1(2)-CN-PT-101 (201) A/B).

These changes are included in DCP 99-119 and several of the field changes associated with DCP-98-130. Additionally, DCP 99-119 the field changes for DCP 98-130, install Y2K ready software and several "human factors" enhancements for the Units 1 and 2 High Capacity SG BD System. DCP 99-119 also provide for the installation of Y2K ready hardware for 2-SS-RM-225, the reinstallation of interposing relay 2-3BDGN02 and the installation of Y2K ready software on a portable computer that will be used to set up radiation monitors (1) 2-SS-RM-125 (225).

6. State the purpose for this change, test, or experiment.

The purpose of this evaluation is to determine and document the acceptability of individually overriding trip signals from several transmitters (see item 5 above) associated with the high capacity BD System. The evaluation also addresses the acceptability of the Y2K changes; human factor enhancements and reinstallation of interposing relay 2-3BDGN02.

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met.

Only one trip signal is to be overridden at any time. Engineering Transmittal SE 99-034 Sets out the compensatory measures to be proceduralized when any system trip is blocked. This ET will provide the basis for revising applicable procedures. The BD System Software and Radiation Monitor will be tested by the NBU Year 2000 Team to ensure year 2000 readiness.

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [✓] No

Part A – Resolution Summary Report

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

The high capacity steam generator blowdown system is designed to automatically shutdown when the system detects that the setpoint for maximum or minimum blowdown flash tank inlet flow (as sensed by 1/ 2-BD-FT-102 (202) A/B/C) has been attained or the blowdown flash tank maximum outlet flow (as sensed by 1/ 2-BD-FT-105 (205)), has been attained. Also, the system automatically shuts down when the setpoint for the blowdown flash tank high pressure (as sensed by 1/ 2-BD-PT-100 (200)), the blowdown flash tank high or low level (as sensed by 1 /2-BD-LT-100 (200)), the blowdown cooler high outlet temperature (as sensed by RTD1 /2-BD-RTD-101 (201)) and the main condenser high pressure (as sensed by 1/ 2-CN-PT-101 (201)) have been attained or exceeded.

During the spring 1998 Unit 1 refueling outage, the Unit 1 High Capacity SG BD System was upgraded to Y2K readiness per DCP 98-130. Also, included in that package were enhancements categorized as human performance improvements requested by the Operations Department. However, the capability for overriding specified system trip signals that were requested by the I&C Department was omitted from the package, because that item had not received a safety review.

DCP 99-119 will implement changes to the Unit 2 High Capacity SG BD System to make it Y2K ready and add human performance enhancements similar to those added during the Unit 1 blowdown system modifications. In addition, both the Units 1 and 2 Systems are to be further enhanced by adding the capability of overriding System trip signals from the individual transmitters listed above. The Unit 2 enhancements will be included in DCP 99-119 and the Unit 1 enhancements will be added by way of a field change to DCP 98-130.

At present, the transmitters listed above cannot be serviced or recalibrated while the high capacity BD system is in service. This is so because it is not possible to disable the automatic trip signal that may be actuated during a maintenance or calibration evolution. In order to facilitate online maintenance or calibration of these transmitters, if the need should arise, the software for the system will be changed to provide the capability for disabling the trip signal from the transmitter that has been selected for maintenance. The software changes will include the addition of a maintenance screen that will include several safety features. The maintenance screen will be accessed from the mimic screen via a button bar titled "Maint. Screen" and a new separate user and password. In the maintenance screen each component that has on line maintenance capability has an "ON" and an "OFF" pushbutton which will not operate if the Startup/Run function is in "Startup", or FW Maint. is in "Yes". Also, these buttons will not operate unless the appropriate device is placed in manual.

When a transmitter is placed in maintenance, the status of the Startup, and the FW Maint. button cannot be changed. Only one transmitter at a time can be placed in maintenance. The transmitter selected for maintenance will enable a flashing red display of "MAINT" in close proximity to the transmitter to visually display its status. This flashing status indicator will be visible from on both the mimic and maintenance screen. The numeric display for the transmitter in maintenance will be displayed on the blowdown computer screen. When an alarm setpoint for the transmitter in maintenance is exceeded an alarm indication will be displayed on the computer screen to verify functionality of the alarm.

CE-821 AC controllers associated with PY/CN201A-2 and PY/CN201B-2 directly feed a steam generator blowdown non-isolated digital input module. This misapplication was a potential cause for a high capacity blowdown trip (Ref. DR N-97-2778 and N-97-3046). DCP 99-119 will incorporate the reconnection of an interposing relay for Unit 2 to eliminate the potential for a spurious high capacity blowdown trip. The same change has already been successfully performed on NAPS Unit 1 via DCP 98-130.

A Human Factors analysis has been performed and the proposed modifications are in compliance with NUREG-0700, STD-GN-0005 and GN-STD-0036. The computer, the software and the programming will be tested by a test plan provided by NBU Year 2000 Team to ensure year 2000 readiness. The Blowdown Radiation Monitor will also be tested by a test plan provided by NBU Year 2000 Team to ensure year 2000 readiness.

None of the changes to be implemented will affect the likelihood of a loss of offsite power to station auxiliaries, a steam generator tube rupture or an excessive load increase incident. These changes affect only the software associated with the high capacity steam generator blowdown system which is in no way connected to safeguards systems designed to operate during the events listed above. Thus the consequences of those accidents are not changed. Compensatory measures to be included in applicable maintenance and operations procedures will prevent failures resulting from loss of flow, temperature or level control. Overpressure protection for the blowdown flash tank will still be available during the activity. The creation of new accident or malfunction possibilities is not introduced. For these reasons, an unreviewed safety question does not exist, and this activity should be allowed.

VIRGINIA POWER



VPAP-3001 - Attachment 3

| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| 99-SE-MOD-14 | [X] North Anna Power Station<br>[ ] Surry Power Station | [X] Unit 1 [ ] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**Part A - Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.

DCP 99-135, "Lube Oil Sample Test Ports"

5. Summarize the change, test, or experiment evaluated.

Lube oil sample test ports are being installed on safety related pumps, 1-CC-P-1A,B and pump motors, 1-CC-P-1A,B, 1-FW-P-3A,B, similar to the installations already completed on non-safety related pumps and pump motors that are operating satisfactorily.

6. State the purpose for this change, test, or experiment.

The lube oil sample test ports provide a method to obtain lube oil samples without removing the equipment from operation. This prevents equipment from having to be rotated off and on just to obtain the lube oil samples.

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met.

None.

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [X] No

**Part A - Resolution Summary (Cont'd)**

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

DCP 99-135 is being issued to install lube oil sample test ports on safety related equipment similar to those installed on non-safety related equipment in Unit 1 and Unit 2 by prior DCPs. The installation of the sample test ports will enable representative lube oil samples to be obtained without equipment shutdowns and without exposing the lube oil systems to contamination. The lube oil samples will be smaller and require less labor for obtaining the samples. The test port is self sealing to prevent leakage, and a cap is supplied with the test port to ensure the system is sealed and doesn't leak oil.

The installation of the lube oil sample test ports does not constitute an unreviewed safety question as defined in 10 CFR 50.59 because it does not:

Increase the probability of occurrence or the consequences of an accident or malfunction of equipment important to safety and previously evaluated in the SAR. Neither component performance nor function will be degraded by the installation. The installation meets the design criteria of the system, and the safety related function of the system is unchanged.

Create a possibility of an accident or malfunction of a different type than any evaluated previously in the SAR. No new degradation mechanisms are created by the installation. No new equipment accidents or malfunctions are created by the installation.

Reduce the margin of safety as defined in the basis of the Technical Specifications and does not require a change to the Technical Specification or Operating License. The performance capabilities, function, reliability and capacity of the affected systems are not altered by the installation.

Reduce the ability to achieve and maintain safe shutdown in the event of a fire.

Increase any environmental impact evaluated in the Final Environmental Statement, change effluents or power levels, have an adverse environmental impact and does not change the Environmental Protection Plan.

VIRGINIA POWER



| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| 99-SE-MOD-019 | [X] North Anna Power Station<br>[ ] Surry Power Station | [X] Unit 1 [X] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**Part A - Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.

DCP 99-142, "CHARGING PUMP MINIMUM FLOW RECIRC ORIFICE REPLACEMENT"

5. Summarize the change, test, or experiment evaluated.

Design change 99-142 will replace the charging pump, 11-stage minimum-flow recirculation orifice assembly with a new 22-stage orifice assembly.

6. State the purpose for this change, test, or experiment.

Based on experience gained in the industry regarding gas voids, it has been postulated that the gas intrusion source for North Anna is caused by gas stripping in the charging pump minimum-flow recirculation line. Specifically, the gas is being mechanically striped from solution by the jetting process in the charging pump mini-flow orifice. Evaluation and testing at other facilities has shown that the orifices were discharging two-phase flow: water and gas bubbles. The two-phase flow returns back to the common charging/SI suction header via the seal water heat exchanger. Two other plants, Duquesne Light's Beaver Valley Power Station and Pacific Gas & Electric's Diablo Canyon Power Station, found that replacing the charging pump recirculation mini-flow orifice with 22-stage orifices specifically designed to eliminate gas stripping, significantly reduced gas voids in the charging header.

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met.

None

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [X] No

**Part A - Resolution Summary Report**

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

The issuance of SOER 97-01, "Potential Loss of High Pressure Injection and Charging Capability from Gas Intrusion", characterized several events in the nuclear industry related to gas intrusion of the high-pressure injection and charging pumps.

A 1989 study conducted at North Anna determined that gas voids do indeed exist in the common 8" and individual 6" charging pump suction headers. At the time of the study, it was believed that gases coming out of solution from the VCT supply caused the gas formation. The study concluded that due to system piping layout and flow velocities during a DBA, ingestion of gas pockets capable of causing HHSI pump damage was not possible.

As a result of discussions with other utilities and by review of OE data, it has been recently concluded that a more likely cause of the gas formation exists. Based on experience gained in the industry regarding gas voids, it has been postulated that the gas intrusion source for North Anna is caused by gas stripping in the charging pump minimum-flow recirculation line. Specifically, the gas is being mechanically stripped from solution by the jetting process in the charging pump mini-flow orifice. Evaluation and testing at other facilities has shown that the orifices were discharging two-phase flow: water and gas bubbles. The two-phase flow returns back to the common charging/SI suction header via the seal water heat exchanger. Two other plants, Duquesne Light's Beaver Valley Power Station and Pacific Gas & Electric's Diablo Canyon Power Station, found that replacing the charging pump recirculation mini-flow orifice with 22-stage orifices specifically designed to eliminate gas stripping, significantly reduced gas voids in the charging header. It is requested that North Anna modify its charging mini-flow recirculation lines by replacing the existing orifices with 22-stage orifices.

**SUMMARY OF SAFETY ANALYSIS**

The modification did not constitute an unreviewed safety question as defined in 10CFR50.59 since it did not:

A) Increase the probability of occurrence or the consequences of an accident or malfunction of equipment important to safety and previously evaluated in UFSAR.

The activity does not generate new initiators that would affect the probability of occurrence for analyzed accidents. The status of the mini-flow recirculation orifice assembly is not a precursor to these accident scenarios. The operational characteristics of the charging pump remain the same. Replacing the charging pump mini-flow recirculation orifice with 22-stage orifices specifically designed to eliminate gas stripping, will significantly reduce gas voids in the charging header. This will increase pump reliability. The new orifice assembly is designed to provide a charging pump recirculation flow rate of 60 gpm, which is the same as the original 11-stage orifice assembly. The modification will not adversely affect ECCS flow characteristics that could challenge flow requirements for existing LOCA analysis or HHSI pump runout limits. Operability of the charging pumps will not be compromised by this activity. The HHSI/charging pump will continue to perform its intended design function for mitigation of the analyzed accidents.

B) Create a possibility for an accident or malfunction of a different type than any evaluated previously in the UFSAR.

Replacement of the charging pump mini-flow recirculation orifice is intended to increase pump reliability without changing pump operating characteristics. The activity will not prevent the charging pump from performing as designed during both normal and DBA conditions. The new 22-stage orifice assembly will develop the same pressure drop and flow rate as the original 11-stage orifice. The new components are constructed of materials that are compatible for use in the CVCS/HHSI system and meet all design pressure/temperature requirements. The pumps will continue to operate in the same manner as before this modification is performed. Accidents or malfunction of equipment of a different type than was previously evaluated is not credible due to the nature of the modification.

C) Reduce the margin of safety as defined in the basis of any Technical Specification.

Charging pump mini-flow recirculation orifice replacement will not have any adverse impact on the Tech Specs associated with the charging pump nor will any margin of safety be affected by this modification. ECCS operability and flow characteristics will not be impacted by this activity.

| 1 Safety Evaluation Number | 2 Applicable Station | 3. Applicable Unit |
|---|---|---|
| 99-SE-MOD-20 | [X] North Anna Power Station<br>[ ] Surry Power Station | [X] Unit 1 [X] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**Part A - Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.
a) North Anna Power Station Technical Specification Change Request No. 371
b) DCP 98-007, Revisions 2 and 3 (FC2 and FC3), FW Flow Calorimetric / North Anna / Units 1 and 2

5. Summarize the change, test, or experiment evaluated.

North Anna Tech Spec Change No. 371 is being intiated to correct the Tech Spec Bases for the Steam Flow - Feed Flow Mismatch Reactor Trip in order to support DCP 98-007, Field Changes 2 and 3. DCP 98-007, FC2 and FC3 provide revised Steam and Feedwater Flow Protection System scaling per commitments made in the original DCP. The scaling changes described below will enhance the operation of the functions described below :

1) Steam Flow Protection and Control will be normalized to Reference Feedwater Flow (i.e., the Feedwater Flow calculated by the P-250 and PCS Computers via Feedwater FLOWCALC). This change will increase the accuracy of Steam Flow Indication and the RPS / ESFAS Steam Flow signal used in the 7300 Process Control System.
2) The Feedwater Flow Transmitters will be re-scaled so that their spans are calculated based on the same parameters as those used in the P-250 and PCS Feedwater FLOWCALC programs. This scaling change will enhance the accuracy of Feedwater Flow indication along with the feedwater flow portion of the Steam Flow / Feed Flow Mismatch RX Trip. In addition, this change coupled with the steam flow changes will improve the operation of the Steam Generator Level Control System (SGLCS) by matching the steam flow signal more closely to the feedwater flow signal. Matching the Steam and Feedwater Flow signals will reduce the offset experienced by the Feedwater Flow Controllers during normal operation.
3) The SFFF Mismatch RX Trip Setpoint will be changed from 34 % of $Flow_{nom}$ to 40 % of $Flow_{nom}$. This change will increase the operating margin for this trip while ensuring that the UFSAR and Design Basis assumptions are still bounded. Tech Spec Change 371 will change the existing incorrect Tech Spec Bases Setpoint values and account for this scaling change.
4) The Steam Flow Feed Flow Mismatch Summing Amplifiers in the Steam Generator Level Control System will be re-scaled to reflect the Post-SGRP design flow of $4.247 * 10^6$ PPH. This change along with the changes described above will improve the operation and stability of the Steam Generator Level Control System based on the design conditions documented in References 21a. and 21b.

6. State the purpose for this change, test, or experiment.

The purpose of DCP 98-007 FC2 and FC3 is to provide revised scaling for the Steam and Feedwater Flow Protection and Control System. These scaling changes will ensure that the Reactor Protection System Trips generated from Steam and Feedwater Flow accurately reflect actual plant conditions and are meeting the Tech Spec Allowable Values. As stated above, the SFFF Mismatch Summator in the SGLCS is being re-scaled to reflect the Post-SGRP Design Flow of $4.247 * 10^6$ PPH at 100 % Power.

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met.
For the DCP Field Changes, FW and STM Flow Transmitter span changes and P-250 / PCS Computer changes must be made / installed prior to startup. For the Technical Specification Change (Bases Change), no changes are needed. CTS 02-99-1806

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [X] No

**Part A – Resolution Summary Report**

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

Statement of Problem

During the preparation of DCP 98-007, discrepancies were identified involving the installed Feedwater Flow Transmitter spans on both units. Specifically, the calculation that determined the Feedwater Flow Transmitter spans for both units (i.e., EE-0445, Revision 0 with ADD00A and ADD00B) assumed that Tap Set 1 on each flow venturi was connected to the respective Channel IV transmitter and that Tap Set 2 was connected to the respective Channel III transmitter. Based on Engineering Transmittal ET SE-99-002, Revision 0, it has been determined that Tap Set 1 is connected to the Channel III transmitters and Tap Set 2 is connected to the Channel IV transmitters. This means that the transmitter spans installed on the Channel III transmitters should be installed on the Channel IV transmitters and the Channel III spans should be installed on the Channel IV transmitters. In addition, a calculation error was found on the span used for transmitter FT-2487. Based on this information, the bounding offset between the existing Feedwater Flow Transmitter spans and the required spans is + 0.661 % of the $\Delta P$ span. This equates to an offset of + 1.13 % of $Flow_{nom}$ at approximately 40 % power and decreases to + 0.46 % of $Flow_{nom}$ at 100 % power (Ref 4.20). These offsets are bounded by the existing margin to the Technical Specification Allowable Value for the SFFF Mismatch RX Trip. Based on this evaluation, it was decided that the re-scaling of the Feedwater Flow Transmitters could wait until the next outage for each unit and that no Unreviewed Safety Question exists concerning Feedwater Flow. Additionally, the advantages of postponing the re-scaling of the transmitters until the outage allows the scaling to be based on process/design inputs that are derived from actual plant data and further, the scaling will be now be based on the same calculational methodology as that used by the P-250 and PCS FLOWCALC programs.

Another item that re-surfaced during the preparation of the DCP was instrument scaling. Specifically, Corporate I&C/C was asked to determine if increasing power (and thus flow) would have any affects on the 7300 Protection and Control System. The review determined that North Anna's Steam and Feedwater Flow Protection System was not exceeding Tech. Specs but was very close on some of the loops. The original DCP stated that Steam Flow would be normalized to Feedwater Flow during the next outage on each unit. Normalizing Steam Flow to Feedwater Flow will ensure that the Reactor Protection System is scaled as close as possible to the ideal values and accurately reflects actual plant operating conditions. Note the example below for the High Steam Flow in 2/3 Lines ESFAS Trip Function (Refer to Figure 1 on Page 2A) :

Referring to Figure 1 on Page 2A, The High Steam Flow Setpoint for Channels 3 and 4 is set at the same voltage value of 8.730 VDC equating to 110 % of $Flow_{nom}$ (i.e., $4.247 * 10^6$ PPH * 1.1 = $4.6717 * 10^6$ PPH). The High Steam Flow Setpoint voltage is calculated based on the average steam pressure for the unit at 100 % power (i.e., known as $P_{ref}$). The calculation of the High Steam Flow Setpoint is provided in Technical Report EE-0085, Appendix 18-2, Revision 0, Turbine First Stage Pressure (TIP) Protection and Control (Ref 21.c). The methodology is illustrated below :

$$V_{STPT} = ( (Flow_{nom} * 1.1) / Flow_{max} )^2 * 10$$

$$V_{STPT} = ( (4.247\ E6 * 1.1) / 5.0\ E6 )^2 * 10$$

$$V_{STPT} = 8.730\ VDC$$

Note that for conditions of $P_{ref}$ , the pressure compensation applied to the raw Steam Flow $\Delta P$ input voltage signal as it applies to the High Steam Flow Setpoint is equal to 1.0. The voltage calculated above is presently installed as the High Steam Flow Setpoint for all the loops in Unit 2. The same also applies for Unit 1.

Continued on Page 2B of 12 .....

Part ____________ - Use an Alpha Suffix Page Number (e.g., 6A of 12)

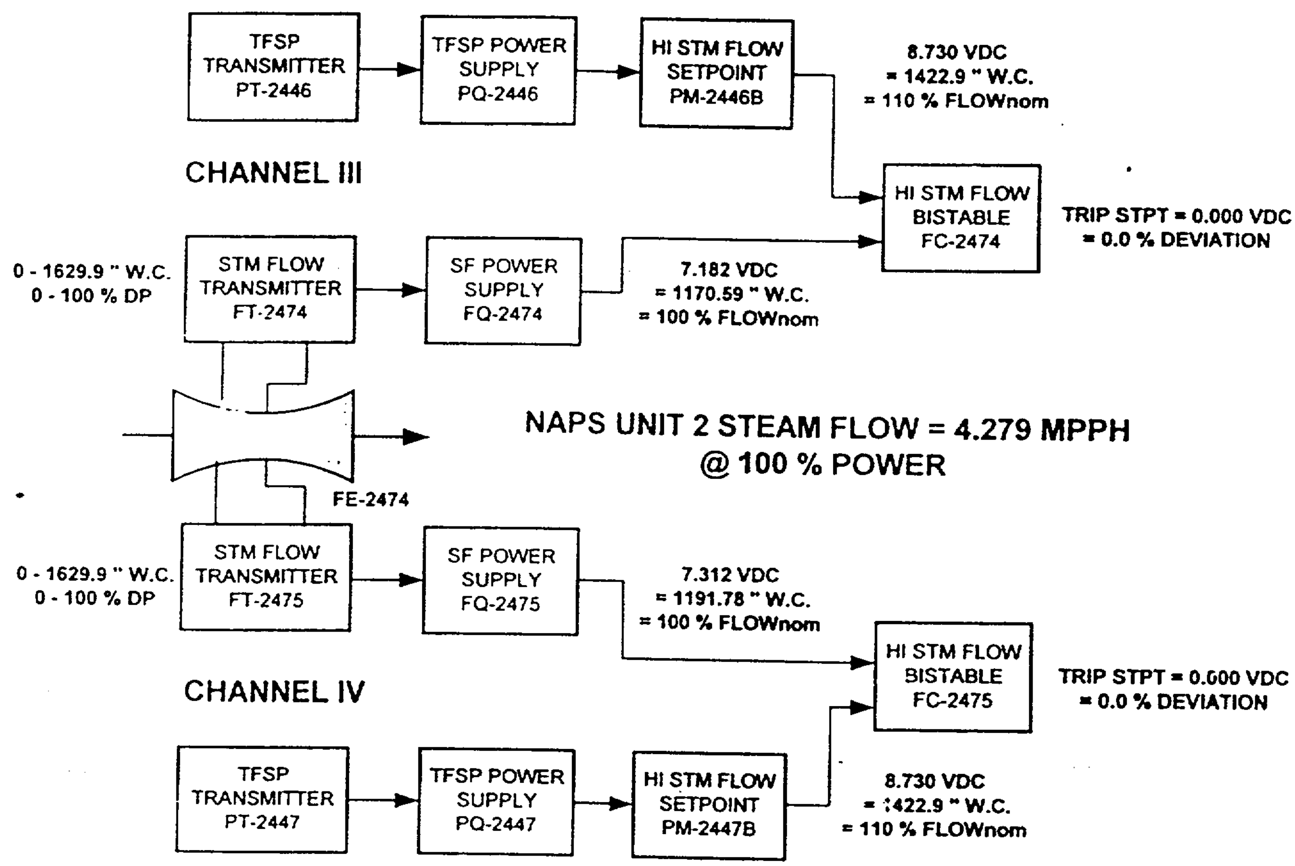


FIGURE 1 - UNIT 2 "LOOP A" HIGH STEAM FLOW IN 2/3 LINES ESFAS TRIP

NOTE :

The transmitter spans (i.e., 0-1629.9 " W.C. is the non-high line pressure corrected span equivalent to 1613 " W. C.) given above are based on the presently installed spans as specified in Instrument Calibration Procedures 2-ICP-MS-F-2474, Revision 6 and 2-ICP-MS-F-2475, Revision 6. All other data shown in Figure 1 above is based on plant data taken from the PCS Computer over a 6 hour period on May 10, 1999. This data can also be found in Technical Report EE-0085, Appendix 12-2, Revision 0, Steam and Feedwater Flow Protection.

**Part ... Use an Alpha Suffix Page Number (e.g., 6A of 12)**

As shown in Figure 1, for the same Reference Flow of 4.279 MPPH (this flow value takes SG Blowdown of 0.03 MPPH into account), the raw Steam Flow ΔP voltage input signal to the High Steam Flow Bistable from Channel 3 (FQ-2474) is different than the raw Steam Flow ΔP voltage input signal to the High Steam Flow Bistable from Channel 4 (FQ-2475). However, the setpoint for both channels is the same as shown above. For ideal conditions, both transmitters should be outputting the same voltage (or close to the same voltage) for the same flowrate. In addition to correcting the voltage offset between channels, both of the Steam Flow Transmitters should be scaled so that the Steam Flow ΔP input voltage to the High Steam Flow Setpoint Bistable at 100 % power is equal to the following :

$$V_{\Delta P} = (Flow_{100\%} \; / \; Flow_{max})^2 * 10$$

$$V_{\Delta P} = (4.279\ E6 \; / \; 5.0\ E6)^2 * 10$$

$$V_{\Delta P} = 7.324\ VDC$$

Like the High Steam Flow Setpoint, for 100 % power conditions, the pressure compensation applied to the raw Steam Flow ΔP input signal should also be equal to 1.0, thus flow is equal to $(\Delta P)^{1/2}$. This means for a normalized system, both Channel 3 and 4 Steam Flow Transmitters would output the same voltage to their respective High Steam Flow Setpoint Bistable even though they are measuring a different ΔP. The maximum offsets for both Units with respect to the "Ideal Value" were analyzed during the preparation of the original DCP and were found to be bounded by Technical Specifications and by the Safety Analysis. However, some of the loops were close to the Tech Spec Allowable value. This is one of the major reasons why Steam Flow is being normalized to Reference Feedwater Flow. This method of normalization is applied to many other Reactor Protection Functions such as ΔT, Reactor Coolant Flow, NIS Power Range and Turbine First Stage Pressure (now known as Turbine Load).

Similar to the High Steam Flow Function illustrated above, the scaling for the Steam Flow Feed Flow (SFFF) Mismatch RX Trip and Steam Flow Indication is also less than ideal. Presently, the Process Gain ($K_P$) used for the Steam Flow Multiplier Divider Square Root (NMD) Card is the same for all channels and all loops on Unit 2. The same also applies for Unit 1. Having the same Process Gain on all the NMD Cards is acceptable if the transmitters are normalized. However, if the transmitters are not normalized and if the NMD Card Process Gain is not set correctly (i.e., based on $P_{ref}$ at 100 % power), then the 7300 Protection System will not accurately represent the actual flow in the loop. This will affect the SFFF Mismatch RX Trip and Control Room indication. The example below illustrates how Steam Flow is calculated based on the current scaling :

From Figure 1 (Page 2A), Unit 2 "Loop A" Reference Flow is 4.279 MPPH. The Steam Flow NMD Card calculates flow using the following Module Equation :

$$V_{FLOW} = (V_{\Delta P} * V_{PRESS} * K_P)^{1/2}$$

Where :

$V_{FLOW}$ = Output voltage from the Steam Flow NMD Card
$V_{\Delta P}$ = Steam Flow ΔP input voltage
$V_{PRESS}$ = Steam Pressure input voltage
$K_P$ = Process Gain = 1.7362 V/V for Unit 2

Using test data from Technical Report EE-0085, Appendix 12-2, Revision 0 (Ref 21.d) and Figure 1 (Page 2A), we have the following calculated Steam Flows for Unit 2 "Loop A", Channels 3 and 4 at 100 % power.

Part ______ - Use an Alpha Suffix Page Number (e.g., 6A of 12)

**Channel 3**

$$V_{FLOW\,CH\,3} = (7.182 * 5.934 * 1.7362)^{1/2}$$

$$V_{FLOW\,CH\,3} = 8.602 \text{ VDC and } FLOW_{CH\,3} = (8.602/10) * 5.0 \text{ E6 PPH}$$

$$FLOW_{CH\,3} = 4.301 \text{ MPPH}$$

**Channel 4**

$$V_{FLOW\,CH\,4} = (7.312 * 5.941 * 1.7362)^{1/2}$$

$$V_{FLOW\,CH\,4} = 8.685 \text{ VDC and } FLOW_{CH\,4} = (8.685/10) * 5.0 \text{ E6 PPH}$$

$$FLOW_{CH\,4} = 4.343 \text{ MPPH}$$

Comparing the flow values above, it can be seen that the Channel 3 and 4 values are different and that neither one matches the Reference Flow of 4.279 MPPH. This Steam Flow offset combined with the Feedwater Flow offset described above was analyzed for worst case conditions during the preparation of DCP 98-007 to ensure that the SFFF Mismatch RX Trip was not exceeding the Tech Spec Allowable Value. The analysis determined that the trip was bounded by Tech Specs because the actual trip setpoint in the plant is set in the conservative direction with respect to the Nominal Setpoint given in Tech Specs by 6.0 % of $Flow_{nom}$. Additionally, the SFFF Mismatch RX Trip is not credited in the Safety Analysis (Ref 21.f) and thus no Safety Margin analysis is required. Based on the above discussion, no Unreviewed Safety Question exists with respect to the SFFF Mismatch RX Trip for current plant conditions.

As stated in Chapter 7.0, Section 7.2.2.3.5, of the UFSAR, the value where the SFFF Mismatch RX Trip is assumed to be available is 50 % Power. The existing setpoint of 34 % of $Flow_{nom}$ and thus 34 % Power is 16 % conservative with respect to this assumed value. The current 16 % margin is excessive for this function based on current plant conditions and is overly bounding when compared to the Channel Statistical Allowance Value for this function (i.e., 6.21 % of $Flow_{max}$ = 7.31 % of $Flow_{nom}$). For this reason, the SFFF Mismatch RX Trip Setpoint on Unit 1 will be changed from the existing setpoint value of 1.448 MPPH based on 34 % of $Flow_{nom}$, Pre-SGRP Design Flow to 1.699 MPPH which is based on the Tech Spec Setpoint value of 40 % of Full Flow at Rated Thermal Power (i.e., Design Flow @ 100 % Power = 0.4 * 4.247 MPPH = 1.699 MPPH). The Unit 2 SFFF Mismatch RX Trip Setpoint will be changed from 1.444 MPPH based on 34 % of $Flow_{nom}$, Post - SGRP Design Flow to 40 % of $Flow_{nom}$ (i.e., 1.699 MPPH, same as Unit 1). With this SFFF Mismatch RX Trip Setpoint change, both units will be set at the same trip setpoint and the plant will recover 6 % operating margin while still remaining within Technical Specification, UFSAR and Design Basis Requirements. In order to implement the Steam Flow - Feed Flow Mismatch Setpoint change, Tech Spec Change No. 371 has been prepared to change the Bases for Section 2.0 Safety Limits and Limiting Safety System Settings, Section 2.2.1. Steam / Feedwater Flow Mismatch and Low Steam Generator Water Level so that the setpoint value will now be specified in terms of % of nominal flow instead of an actual flow value given in lbs/hour. See Tech Spec Change No. 371 for the exact wording of the Bases change.

When Steam Flow is properly normalized to Feedwater Flow, both the raw Steam Flow ΔP voltage and the calculated Steam Flow voltage from each channels NMD Card will be equal or close to the required (i.e., the Ideal) values as described above. Additionally, the calculated flow from the Steam Flow NMD Card will closely match the Reference Flow when the plant is at 100 % power. An example of the effects of normalizing Steam Flow to Feedwater is provided in DCP 98-007, Revision 2 (FC2), Section 2.0.

**Part - Use an Alpha Suffix Page Number (e.g., 6A of 12)**

As a result of re-scaling the Feedwater Flow Transmitters and normalizing Steam Flow to Feed Flow, the FLOWCALC programs used in the P-250 and PCS Computers must be updated to reflect the new transmitter spans and Steam Flow NMD Card Process Gain ($K_P$). These changes will be transparent to Operations and will not affect the calculation of Steam Flow or Feedwater Flow in any way as long as the NEW (correct) transmitter spans and NMD Card Process Gains (PCS Computer only) are entered into the FLOWCALC program files. The changes made to the P-250 and PCS Computers will be managed and controlled in accordance with VPAP-0306. Therefore, an Unreviewed Safety Question does not exist with respect to the FLOWCALC programs or Reactor Power.

Lastly, the Steam Flow / Feed Flow Mismatch Summing Amplifier used in the Steam Generator Level Control System is being re-scaled to reflect the Post-SGRP Design Flow of $4.247 * 10^6$ PPH. At the present time, the scaling installed on this card represents the Pre-SGRP Design Flow of $4.26 * 10^6$ PPH. The scaling change made on the three SFFF Mismatch Summing Amplifiers in each unit will be minimal and will not affect or even be noticeable to plant operations. These summing amplifiers are part of the NSSS Control System and thus they are not addressed in the Safety Analysis or in Technical Specifications.

To summarize, the scaling changes included in DCP 98-007 FC2 and FC3 will enhance the accuracy of the Steam and Feedwater Flow portions of the Westinghouse 7300 Protection and Control System. These changes will have no impact on the Safety Margins that are in place for the functions derived from these parameters. In addition, these scaling changes will not change the calculational results of the Feedwater or Steam FLOWCALC programs in the P-250 or PCS Computers. In fact, these changes will increase the margin of safety for the applicable trip functions and make the Control Room Indications much more accurate.

**99-SE-MOD-21**

**Description**
DCP-99-145 makes permanent a Temporary Modification (TM N2-1128). This involves replacement of buffer amplifier cards with thermocouple amplifier cards for three feedwater temperature computer inputs. DCP 99-148 makes these card changes via DCP, no TM involved.

**Summary**
This activity does not involve any physical modification to the facility. The new thermocouple amplifier (TC) cards (installed by TM N2-1128) are manufactured by the same company as the buffer amplifier (BA) cards, and they are designed to fit the same slots. Bench testing and the performance since having been installed by TM has shown that the TC card has a more stable output than the BA card. The affected cards send a MFW temperature signal to the plant computer system (PCS) and emergency response facility computer system (ERFCS) only. The signal to the P-250 is not affected. Thus, the P-250 FW flow calorimetric is not affected by this activity.

Operations department calorimetric procedures currently "auctioneer" to the most conservative (or highest power) calorimetric indication. Currently the Unit 1 and Unit 2 calorimetrics using their PCS are the highest, thus they are used as the official indication. Since the accuracy of the calorimetric is in question due to the sensitivity of the BA cards to instrument drift, this condition may be requiring an unnecessary reduction in unit electrical output.

Failure of the activity, for the near term, is bounded by the evaluations performed for the FW flow calorimetric performed under 99-SE-MOD-01. Additionally, the PCS indications of FW temperature or FW flow calorimetric will not be adversely affected. This has been proven empirically by comparing the results obtained with the new cards vice U-1 results using the old (pre-modification) cards. Thus, there is no adverse affect on nuclear safety. No new accidents are created, and consequences of analyzed accidents are not affected. There is no reduction in the margin of safety or ability to mitigate accidents. For these reasons, an unreviewed safety question does not exist.

Since the activity will install amplifier cards in the circuit that are better suited for the application and result in a more accurate FW flow calorimetric, unnecessary reductions in unit electrical output may be eliminated. Therefore, this activity should be allowed.

| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| 99-SE-MOD-24 REV. 1 | [X] North Anna Power Station<br>[ ] Surry Power Station | [X] Unit 1 [ ] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**Part A - Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.

DC 97-007 USFAR update #99-026

5. Summarize the change, test, or experiment evaluated.

Proposed changes consist of: (1) rewiring the over excitation signal to trip main generator breaker, the exciter field breaker and the turbine auto stop solenoid trip, to prevent damage to the main generator and to lock-in the trip indication for over excitation, (2) a test switch will not be provided in circuit 1SPGNO2 to defeat the K3 over excitation signal (as provided for unit 2) since breaker G-12 will be open when the generator is off line, (3) adding a Percent Negative Sequence Ammeter, on the generator control panel, wired to the existing SGC Negative Sequence Relay to provide a visual indication of the Percent Negative Sequence Current in the Main Generator. (4) providing "NEGATIVE SEQUENCE ALERT" annunciation in the control room to alert the operator of the degrading condition and allow for operator action, before unit trip occurs, (5) additions and or corrections to the event recorder for: (a) switchyard breakers 11& 1C, (b) Isophase Duct Backup Lockout Relay, (c) switchyard aux relay turbine trip and (d) Generator Breaker G12, (6) Combine "GEN DIFF LO RELAY TURB TRIP" and "GEN BACKUP LO RELAY TURB TRIP" annunciator windows into a single window "GEN LO RELAY TURB TRIP".

6. State the purpose for this change, test, or experiment.

To enhance the protection of the main generator against operating as an induction generator. To improve the operators visual indication of the negative sequence current in the generator and to support improved operator response to high negative sequence current. To lock-in the trip indications for the Volts/Hertz Relay. To increase and/or correct the information provided to the event recorder.

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met.

None

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [X] No

**Part A - Resolution Summary Report**

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

Implementation of this DCP (i.e. tie-ins) will be performed during a unit outage of sufficient duration to support modifications and testing of modifications prior to return of the unit to service. Some non-outage work can be performed with Operations approval. The implementation of this DCP will improve the protection of the unit main generator and improve the ability of the operator to monitor generator status related to negative sequence current and possibly avoid inappropriate unit trips. The work involved is discussed in detail below.

At present, during an over excitation condition when the unit is "on-line, the OXP-1 relay K3 operates to trip the Exciter Field Breaker, however the generator remains tied to the system. The generator will act as an induction generator when loosing its field and draw high reactive current. The high reactive current will cause rotor and stator temperatures to increase and will damage the generator if the generator is not removed (disconnected) from the system in time. Therefore this DCP modifies this circuit and the K3 relay will now trip the 86BU lockout which trips the exciter field breaker, the generator breaker and turbine via the turbine auto stop solenoid trip. The K3 relay contacts will not be isolated, by a test switch as done for unit 2, to prevent tripping of the G-12 breaker when unit 1 is off line and maintenance is performed in the voltage regulator cabinet or the K3 relay circuitry is being tested. When unit 1 is off line, the breaker G-12 is open. Therefore there is no need to be concerned about tripping the breaker G-12.

This DCP will combine the "GEN DIFF LO RELAY TURB TRIP" and "GEN BACKUP LO RELAY TURB TRIP" annunciator windows into a single window "GEN LO RELAY TURB TRIP".

Currently, the only visual indication of negative sequence current is the alarm light on the SGC relay in the Emergency Switchgear Room which indicates that the negative sequence current has reached the relay alarm set point. The annunciator window 1E-55 will be connected to the relay alarm contacts and will provide the operator in the control room a visual indication when the relay alarm set point is reached. The addition of the percent negative sequence ammeter in the Emergency Switchgear Room will allow the touring operator or an auxiliary operator to trend the negative sequence current, sensed by the (SGC) negative sequence relay. The combination of the ammeter and the annunciator can possibly allow the control room operator to take the necessary action to prevent a unit trip. The magnitude of the negative sequence current impacts the time the operator has to react to the abnormal condition and in cases where the negative sequence current is high may preclude operator action prior to relay operation and thereby trip the unit. The ammeter label shows a range for expected normal readings and instructions for action to take if the reading is outside of the specified range. For cases, where the current is high enough to cause the annunciator to activate in the control room, response will be per the appropriate Annunciator Procedure.

The Event recorder is being changed to provide information for the Switchyard PCBs 11 & 1C, Isolated Phase Duct Backup Lockout Relay Trip, Switchyard BU AUX Relay Trip and Generator Breaker G12.

This work does not create the possibility of an accident of a different type than the type previously evaluated in the Safety Analysis Report. The contacts for over excitation relay are relocated from the Exciter Field Breaker Control circuit 1EXPN01 to the Generator Over Excitation portion of the circuit 1SPGN02. This arrangement will trip the exciter field breaker, the generator breaker and the turbine auto stop solenoid. This will cause a turbine trip and in many cases (above 30% power) a reactor trip, however, these are previously analyzed conditions.

This work does not increase the probability of occurrence of a malfunction identified in the Safety Analysis Report (SAR). This work is non-safety. Tripping the turbine and the main generator possibly resulting in the tripping of the reactor is discussed in Section 15.2.7 of the UFSAR.

(continued on page 2A of 12)

Part A page 2A of 12 - Use an Alpha Suffix Page Number (e.g. 6A of 12)

18 (continued)

While on line, the unit (turbine and generator in all cases, and reactor under most conditions) will now be tripped on overexcitation by either the Beckwith volts per hertz overexcitation relay (present design) or the Westinghouse exciter circuit (K3 relay). Prior to this modification, the Westinghouse circuit (K3 relay) only tripped the exciter field breaker if the unit was on-line. By tripping the unit using the Westinghouse overexcitation detection, the trip could in most cases occur before the Beckwith relay would have tripped the unit and thereby improves the probability of trip before generator damage occurs. Additionally this modification will provide for a lock-in of the overexcitation trip indication. By providing a trip prior to possibly damaging the generator the probability of damage to a major non-safety component has been reduced with no adverse impact on probability of other malfunctions.

This work does not affect the margin of safety of or require any changes to any part of the Tech. Specs. or the Operating License.

This work is non-safety and does not result in any changes to the Tech. Specs. or the Operating License. The input signal for over excitation of the main generator is relocated to another circuit to enable the tripping of the generator breaker, the exciter field breaker and the turbine auto stop solenoid trip by tripping the 86BU lockout relay. The tripping circuits for the exciter field breaker and the generator breaker are existing.

Based on the review, an unreviewed safety question does not exist, as a result of the reworking the Westinghouse overexcitation signal to trip the exciter field breaker, the generator breaker and the turbine auto trip stop solenoid, reworking overexcitation trip indication, providing annunciation and remote indication of negative sequence current, revising generator lock out annuncitation and modifying the identification of points on the event recorder.

Also, there is no impact to the environment or increase in occupational exposure as all work is within clean areas of the service building and the turbine building.

Visual enhancement is provided to monitor the percent negative sequence current in the main generator By the addition of the ammeter in the Emergency Switchgear Room and the "NEG SEQUENCE ALERT" annunciator window in the control room.

Tripping for negative sequence current is not changed by this DCP. Visual enhancement is provided to monitor the percent negative sequence current in the main generator by the addition of the percent negative sequence current ammeter in the Emergency Switchgear Room and the "NEG SEQUENCE ALERT" annunciator window in the control room. The visual enhancement will reduce the probability of a unit trip, due to negative sequence current, because in some cases the operator may be able to take action to reduce the negative sequence current below the trip setpoint before the time delay expires.

VIRGINIA POWER

VPAP-3001 - Attachment 3

| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| 99-SE-MOD-28 Rev. 1 | [X] North Anna Power Station<br>[ ] Surry Power Station | [X] Unit 1 [X] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**Part A - Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.

DCP 99-130, Auxiliary Building Central Area Exhaust Damper Instrument Air & Electrical Power Modification/ NAPS Unit 1 & 2
NSS Implementing Procedure WP-G99130, Test Engineering Procedure D-NAT-99-130-1

5. Summarize the change, test, or experiment evaluated.

The design change enhances the ability to operate the Auxiliary Building central Area exhaust dampers after a seismic event or loss of offsite power by adding a seismic reserve air supply, upgrading the damper instrument air supply tubing to seismic category I and upgrading the power supply to the control SOVs from a safety related source. The design change also provides damper position indication for compliance with Reg. Guide 1.97 requirements.

6. State the purpose for this change, test, or experiment.

Deviation Report N98-0395 and PPR 98-001 were written to identify ventilation concerns with post-LOCA ECCS leakage and airborne contamination. UFSAR section 15.4.1.7 identifies that the Auxiliary Building Central Area ventilation system must be manually aligned to filtered exhaust and to account for the manual realignment, a 60-minute delay in filtration of ECCS leakage is included in the analysis of doses resulting from a LOCA. In the event of a loss of offsite power, the system can not be realigned to the filtered exhaust configuration due to damper fail positions. Reg. Guide 1.52 section C.2.c specifies that all components of an engineered-safety-feature atmospheric cleanup system should be designated as seismic Category I. Section C.2.h specifies that power supply and distribution should be designed in accordance with IEEE-308. UFSAR Table 6.2-51, COMPLIANCE WITH REGULATORY GUIDE 1.52, REV. 1, indicates that the system meets the C.2.c and C.2.h requirements. Contrary to these requirements, the instrument air supply and the power source that controls the Auxiliary Building Central Area exhaust damper operation for filtered exhaust alignment are not in compliance. In addition, UFSAR section 8.4.8.2 states "Bypass dampers are provided for each system and filter assembly. Two pressure-tight dampers are installed in series to satisfy the single-failure criterion at locations that would permit contaminated exhaust to leak around the filter bank". The Auxiliary Building Central Area dampers may not fulfill this requirement with the current instrument air tubing configuration. Design Change 99-130 will upgrade and configure components to comply with the design and license basis criteria.

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met.

See attached item 7, page 1A

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [X] No

Part [illegible] Use Alpha Suffix Page Number (e.g. 8A of 12)

7.
The accident analysis assumes manual alignment of the Auxiliary Building Central Area exhaust for filtration of ECCS leakage within 60 minutes after accident initiation.

The central area exhaust system has four dampers, two by-pass dampers in series and two filtration dampers, one on the filter inlet and one on the filter outlet.

Two activities during DCP implementation will directly affect the operability of the Central Area exhaust system dampers. Demolition and tie-in of instrument air and electrical power will render control of all four Auxiliary Building Central Area exhaust dampers as inoperable. Installation of the actuation arms for position indication on the damper linkage will also impact damper operation.

To maintain compliance with the accident analysis, the Auxiliary Building Central Area exhaust dampers will be blocked/mechanically secured in their filtration positions. The instrument air and electrical tie-ins and the actuation arm installations will be performed with the dampers blocked. The by-pass dampers will still be functional as isolation devices and the filtration dampers will be positioned to allow filtration but opening and closing function from the control room will not be possible. NSS implementation procedure WP-G99130 will procedurally control the blocking and unblocking of the dampers with sign-off steps for the Operations Shift Supervisor. The implementation steps identify that the dampers are blocked in the filtration positions. Steps are also included for the Operations Shift Supervisor sign-off when the blocks/mechanical restraints are removed and the dampers have been restored.

Testing of individual components will be performed with the dampers blocked and the actuators disconnected. During functional testing to stroke the dampers, the actuators are reconnected and the dampers are unblocked. As a contingency, steps are included in the Test Engineering Procedure D-NAT-99-130-1 to re-establish the dampers in their blocked accident positions if functional testing (stroking the dampers) produces unacceptable results.

**Part A: Resolution Summary Report**

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

The Auxiliary Building Central Area exhaust serves the charging pump cubicles to maintain temperature and to provide the availability of a filtered ventilation exhaust path during accident conditions.

Design Change 99-130 was initiated to bring Auxiliary Building Central Area exhaust system physical plant components into compliance to perform functions discussed in the UFSAR. New SOVs, air accumulators, air pressure regulators, check valves, isolation valves and tubing will be installed to seismic category 1 requirements. Backup air with separate air supply tubing to each of the in-line dampers will be controlled through redundant SOVs to meet single-failure criteria. Copper tubing will be installed between an existing vent valve and the accumulator isolation valves. Seismically supported stainless steel tubing will be installed from the accumulator isolation valves to the check valves and air accumulators. The instrument air supply tubing from the air accumulators to the air pressure regulators, SOVs and damper actuators will be installed with seismically supported stainless steel tubing. Electrical power to the new SOVs will be supplied from safety-related 120 VAC Vital Buses 1-I and 2-III.

UNREVIEWED SAFETY QUESTION ASSESSMENT:

1) Accident probability has not been increased because the design change conforms to the requirements of the applicable codes and standards. The upgrade of instrument air components and power source do not increase the probability of occurrence of an accident because the ventilation system function, damper arrangement and operation have not changed. The Auxiliary Building Central Area exhaust ventilation system can not initiate an accident.

2) Accident consequences are not increased. The Auxiliary Building Central Area exhaust serves the charging pump cubicles to provide the availability of a filtered ventilation exhaust path during accident conditions. The upgrade of instrument air components and power source enhances the ability for operation of the system in performance of its intended function. Administrative limits for ECCS leakage maintain compliance with system licensing and design bases in the event of an unfiltered release.

3) No unique accident probabilities are created.

4) Margin of Safety is maintained because the design meets the requirement of the applicable codes and standards.

VIRGINIA POWER



| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| 00-SE-MOD- 13 | [x] North Anna Power Station<br>[ ] Surry Power Station | [ ] Unit 1 [x] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**Part A - Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.

Design Change 00-138 "RVLIS Sensor Bellows Reorientation" – Unit 2

5. Summarize the change, test, or experiment evaluated.

The "A" and "B" train reactor head sensor bellows assemblies in the reactor vessel level instrumentation system (RVLIS) will be inverted such that the capillary connections are reoriented from the top to the bottom of the sensor assemblies in order to preclude air intrusion into the sealed tubing system.

6. State the purpose for this change, test, or experiment.

Westinghouse Technical Bulletin TB-101R1 "RVLIS Calibration Anomalies Due to Air Inleakage" reported that at several plants, recalibration of the reactor vessel level instrumentation system during refueling shutdowns have indicated that air inleakage into the sealed portion of the system have caused errors in readings and inaccurate calibrations. In almost all cases, air was found in the section of tubing from the reactor vessel head sensor and the operating deck. To prevent possible air inleakage through the sensor bellows, o-ring seal, and fill valve, Westinghouse recommends that the vessel head sensor be inverted so that the capillary tubing connection is on the bottom.

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met.

None

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [x] No

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

Westinghouse Technical Bulletin TB-101R1 "RVLIS Calibration Anomalies Due to Air Inleakage" reported that at several plants, recalibration of the reactor vessel level instrumentation system during refueling shutdowns have indicated that air inleakage into the sealed portion of the system have caused errors in readings and inaccurate calibrations. In almost all cases, air was found in the section of tubing from the reactor vessel head sensor and the operating deck. Westinghouse determined that when the sensor is disconnnected from the reactor for refueling, the sensor bellows is exposed to atmospheric pressure, and the water in the tubing above this elevation is below atmospheric pressure. There are three locations with mechanical connections, having the potential for inleakage: the fill valves at the head connection and operating deck, and the bellows or its o-ring seal in the head sensor.

To prevent possible air inleakage through the sensor bellows, o-ring seal, and reactor head connection fill valve, Westinghouse recommends that the vessel head sensor be inverted so that the capillary tubing connection is on the bottom. During refueling, the bellows and seal would then be exposed to a positive pressure and could be covered with water to block air inleakage. Also, air trapped in the bellows could not reach the tubing connection at the bottom of the bellows. The modification also moves the fill valve at the sensor to a lower elevation, resulting in a positive pressure at this potential leakage location. In order to accomplish the sensor inversion, the existing capillary tubing will be cut and additional tubing added. Westinghouse reports that they have not been advised of any air inleakage problems where the sensors were installed in the inverted position.

Also, based on experience reorienting the RVLIS bellows on Unit 1 (Design Change No. 00-101 "RVLIS Sensor Bellows Reorientation"), upon rotation of the reactor head sensor bellows, the wide part of the assembly housing may interfere with the existing sensor protection plates that surround the bellows assemblies. (Items 5 on drawing 13075-FK-13AB). In order to avoid the interference between the sensor assembly housings and the sensor protection plates, the sensor assemblies will be moved horizontally back towards the reactor cavity wall approximately 1.625" on the existing assembly support. Two new holes for the U-bolt support mounting bolts will be drilled, while reusing one of the existing holes for each U-bolt. A new 3/8" Swagelok union and short length of 3/8" tubing will be installed in the removable section of 3/8"-RC-648-ICN9-Q2 between isolation valve 2-RC-209 and the existing 3/4" x 3/8" Swagelok reducer to accommodate the horizontal relocation of the sensor housing assemblies. The additional Swagelok union connection is being provided for ease of future repair of the 3/4" x 3/8" Swagelok reducer connection which is taken apart each refueling outage, as well as for ease of installation.

The reorientation of the RVLIS reactor head sensor bellows assemblies does not create an unreviewed safety question. The operation and function of the RVLIS system is not affected. The sensor bellows assemblies are mechanical pressure boundary separation devices that are designed to operate in any position. The design and installation of the new tubing extension pieces is consistent with the original system design requirements. Thus, this design change does not affect any previously evaluated accidents or create any new accidents of a different type.

In accordance with Technical Specifications 3.3.3.6, the new reorientation of the RVLIS sensor assemblies will be performed during a refueling outage when the RVLIS system may be removed from service for maintenance.

VIRGINIA POWER



| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| **00-SE-MOD-014** | [X] North Anna Power Station<br>[ ] Surry Power Station | [X] Unit 1 [X] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**Part A - Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.

DCP 00-147, MFRV ACTUATOR AIR SUPPLY MODIFICATION UNIT 1
DCP 00-148, MFRV ACTUATOR AIR SUPPLY MODIFICATION UNIT 2

5. Summarize the change, test, or experiment evaluated.

The design change will remove the Air Lock-up valves and the air supply, filter regulators from each Main Feedwater Regulating Valve (MFRV) actuator assembly. The filter regulator will be replaced with an in-line air filter with the same micron rating.

6. State the purpose for this change, test, or experiment.

The MFRVs can safely operate as designed without these actuator components. Failure of these components in their current configuration could lead to a loss of MFRV control, which could jeopardize Unit operation. Removal of these components will improve system reliability and maintainability.

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met.

None

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [X] No

**Part A – Resolution Summary Report**

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

The MFRVs were modified in 1993 which replaced the Copes-Vulcan valve trim and spring diaphragm type actuator with the current CCI Drag trim and pneumatic piston actuator. This retrofit included the installation of the VB-11 air lock-up valve (1/2-FW-AOV-1/2 4XX-1) to each actuator assembly. The air lock-up valve was added to allow the MFRV to fail close when IA decreased to 65 psig or lower. The previous failure mechanism was provided by the actuator spring, which overcame the force exerted on the diaphragm by a decreasing IA supply to shut the valve. Recent studies have concluded that the air lock-up valve can be removed without adverse affect to system operation. Consultations with the actuator manufacturer (CCI) and actual testing have confirmed that the MFRVs will fail close on a local, catastrophic loss of IA. On a gradual loss of IA header pressure, the MFRVs will no longer trip close at 65 psig. However, 1/2-AP-28 requires the reactor be tripped and the MFRVs be closed in the event that IA pressure decreases to less than 70 psig. Even without operator action, the MFRVs will eventually fail close on a gradual loss of IA when the weight of the valve plug and stem overcome the forces acting on the pneumatic piston.

The MFRV actuators are currently supplied with IA regulated to 100 psig. IA system pressure typically runs at approximately 105 psig upstream of the filter regulator. The filter regulator can be removed without any adverse affects to actuator components or the MFRVs themselves. This modification will not affect the existing MFRV closure time for isolating Main Feedwater upon receipt of an ESF actuation signal. The volume tank is currently supplied with unregulated IA and will remain in that configuration following implementation of this design change. An air filter with the same micron rating will be installed such that all MFRV actuator components receive a filtered air supply. Eliminating the air regulator will remove a component that has exhibited air leakage problems without sacrificing system operation.

This modification should be allowed since it will increase system reliability and maintainability without adversely affecting FW system operation.

**SUMMARY OF SAFETY ANALYSIS**

The modification did not constitute an unreviewed safety question as defined in 10CFR50.59 since it did not:

A) Increase the probability of occurrence or the consequences of an accident or malfunction of equipment important to safety and previously evaluated in UFSAR.

The activity will not generate new initiators that would affect the probability of occurrence for existing accidents. MFRV control and operation remain unchanged. Since the fail-safe operation of the pneumatic actuator remains unchanged by this modification, the probability to prevent isolation on an ESF signal is not increased. The valves will continue to fail close on a loss of Instrument Air without the air lock-up valve in place. The modification should improve valve reliability and maintainability. The MFRVs can operate safely without the regulators while maintaining air filter requirements with the installation of an in-line air filter. Removing a component (air lock-up valve) whose failure could cause a sudden closure of the feed reg valve reduces the potential for the MFRV to inadvertently fail open or closed. Plant procedures currently exist that require the reactor be tripped and the MFRVs be closed in the event that IA pressure decreases to less than 70 psig. Operation and control of the MFRVs remains unchanged by this activity.

B) Create a possibility for an accident or malfunction of a different type than any evaluated previously in the UFSAR.

Malfunction of equipment of a different type than was previously evaluated is not credible due to the nature of the modification. Removal of the regulator and lock-up valve will not create new equipment malfunctions. Types of malfunctions such as feed reg valve spurious closure, erratic control, and overfeed presently exist in the SAR and are not changed by this modification. The new air filter is constructed of materials that is compatible for use in the IA system, has the same filtering requirements as the original filter regulator, and meets all design pressure/temperature requirements. The ability of the FW system to maintain its code integrity will not be compromised and the system will continue to operate in the same manner as before this modification is performed. The possibility of generating a different type of accident than previously evaluated is not credible.

C) Reduce the margin of safety as defined in the basis of any Technical Specification.

The activity will not have any adverse impact on the Tech Specs associated with the FW system nor will any margin of safety be affected by this modification. Following implementation of the modification, testing will be performed to ensure compliance with Tech Spec 3.3.2.1. The margin of safety has not been reduced since the FW system will still be isolated within the time stated in the Tech Specs. Tech Spec basis remains unaffected by this activity.

VIRGINIA POWER

# Safety Evaluation



VPAP-3001 - Attachment 3

| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| 00-SE-MOD-16 | [x] North Anna Power Station<br>[ ] Surry Power Station | [x] Unit 1 [x] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**Part A – Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.

**DCP #00-005; VPAP-0809; NAPS UFSAR, Section 9.6.4.4 & Plant Issue Resolution N-2000-0282-R3 & R4**

5. Summarize the change, test, or experiment evaluated.

**Add two (2), newly identified NUREG-0612 special lifting devices to VPAP-0809 and NAPS UFSAR, Section 9.6.4.4, to officially document the existence of the Reactor Head Stud Rack Lift Rig & Reactor Cavity Seal Ring Flip Rig. Modify the bail hook of the Reactor Head Stud Rack Lift Rig to correct an adverse bail hook detail and add a seal weld to the lug detail of the Reactor Cavity Seal Ring Flip Rig to improve the corrosion resistance of the lug weld detail.**

6. State the purpose for this change, test, or experiment.

**In response to Plant Issue Resolution N-2000-0282-R3 & R4, two (2) new NUREG-0612 special lifting devices were identified. These special lifting devices need to be modified and officially documented into the NAPS NUREG-0612 program. Documentation will be controlled under the associated NAPS UFSAR Change Request and CDS forms in DCP No. 00-005. Modifications will be implemented under DCP No. 00-005.**

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met.

**No limiting conditions exist for this Safety Evaluation. The special requirements, assumed for this Safety Evaluation, are as stated for NUREG-0612 special lifting devices in VPAP-0809. The formal tracking mechanism to ensure implementation of these special requirements will be tracked under the corrective action assignments to Plant Issue Resolution Nos. N-2000-0282-R3 & R4. These tracking mechanisms will ensure that the modifications to the two-(2), new NUREG-0612 special lifting devices, discussed in DCP No. 00-005, have been completed and that the appropriate sections of NAPS UFSAR and VPAP-0809 have been revised to reflect the addition of these two-(2) new special lifting devices into the NAPS NUREG-0612 program, specifically W.O. 5900435237-01 thru 07 & 5900435269-01.**

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [X] No

**Part A - Resolution Summary Report**

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

The major issues associated with this Safety Evaluation deal with the modifications needed to bring the following two (2), newly identified special lifting devices into programmatic compliance with the Phase I guidelines of NUREG-0612 ("Heavy Loads"), as stated in NAPS UFSAR, Section 9.6 and VPAP-0809: Reactor Vessel Head Stud Rack and the Reactor Cavity Seal Ring Lift Rig.

NAPS NUREG-0612 Phase I report has established a heavy load as any load that weighs more than 2,000 pounds. A load is subject to the requirements of NUREG-0612 if it exceeds 2,000 pounds and is carried over irradiated fuel, safe shutdown or decay heat removal equipment. The Reactor Vessel Head Stud Rack Lift Rig is used inside containment buildings to temporarily hold vessel head studs during head removal and replacement during refueling outages. The stud rack weighs more than 2,000 pounds when empty and shall constitute a NUREG-0612 heavy load lift whenever moved inside containment, loaded or unloaded. The Reactor Cavity Seal Ring Flip Rig is used inside the containment buildings to turn the reactor seal ring over for seal replacement during refueling outages. The flip rig weighs less than 2,000 pounds empty. The reactor cavity seal ring weighs approximately 18,000 pounds. Under the Phase I guidelines of NUREG-0612, the flip rig would be considered to be a "heavy load" lift, whenever loaded with the reactor cavity seal ring inside the containment buildings.

In accordance with US NRC NUREG-0612, Section 5.1.1(4), "Special Lifting Devices", special lifting devices should satisfy the guidelines of ANSI N14.6-1978, "Standard for Special Lifting Devices for Shipping Containers Weighing 10,000 pounds (4500 kg) or More for Nuclear Materials". Virginia Power's original response to this NUREG-0612 Phase I guideline is outlined in NAPS UFSAR, Section 9.6.4.4. In summary, these special lifting devices were not in strict compliance with the ANSI N14.6-1978 requirements for design, fabrication, acceptance testing, and maintenance, and continuing compliance, as noted in the following discussions.

No official design or fabrication documentation could be located for either special lifting device. Engineering visual inspections and evaluations have concluded that both special lifting devices appear to have been fabricated with good quality workmanship, out of materials at least equal to ASTM A 36. Calculation Addendum CE-0798, Revs. 1B and 1C have demonstrated that all shear and tensile stresses meet the allowable stress limits of ANSI N14.6-1978 (i.e. F.S. $\geq$ 3.0 for yield and F.S. $\geq$ 5.0 for ultimate tensile strength) for both special lifting devices. In addition, the stud racks and the spreader beams for the flip rig have been checked against AISC (ASD), 9th Edition to ensure that compressive buckling does not preclude either special lifting device from safely supporting its full rated load capacity. Design calculations and "as-built" DCP sketches have been prepared to document the design and final configuration of these special lifting devices.

With respect to acceptance testing and maintenance, ANSI N14.6-1978 requires that special lifting devices receive annual load tests at 150% of the rated load capacity or annual dimensional, visual and non-destructive testing. By virtue of the satisfactory initial 150% load test that were performed and the prior-to-lift visual inspections that are required, annual 150% load tests or annual dimensional, visual and non-destructive testing may be waived. To ensure a higher level of reliability, periodic non-destructive examinations will be performed under the NAPS 10-year augmented ISI Program. The US NRC has previously accepted, for other NUREG-0612 special lifting devices, prior-to-lift visual inspections, coupled with periodic nondestructive examinations of critical elements under the NAPS 10-year augmented ISI Program, in lieu of annual 150% load testing (reference NAPS UFSAR, Section 9.6.4.4). Similarly, the 150% annual load tests or annual visual dimension and nondestructive examinations, as specified in ANSI N14.6-1978, may be waived for these two-(2) types of special lifting devices.

NAPS requires that all NUREG-0612 special lifting devices be subject to a non-destructive examination (NDE) program, which will provide for periodic inspection and NDE of all critical welds and critical parts over a normal inservice inspection interval of 10 years. Specific baseline and 10-year inservice inspection attributes are provided in Appendix 2-2 for the stud racks. Based on the above Safety Evaluation discussions, the following conclusions have been reached for these special lifting devices: (1) All shear and tensile stresses meet the design criteria of ANSI N14.6-1978. (2) ANSI N14.6-1978 requirements for design, fabrication, and quality assurance are generally in agreement with those used for these devices. (3) Although not in strict compliance with ANSI N14.6-1978 requirements, prior-to-lift visual inspection of the load line and 10-year interval NDE of critical welds and critical parts, meets the intent of ANSI N14.6-1978 for acceptance testing and maintenance.

Similar conclusions were originally reached in NAPS UFSAR, Section 9.6.4.4, to justify NUREG-0612 Phase I programmatic compliance for the special lifting devices associated with the reactor vessel heads, reactor internals, and reactor coolant pump motors. Therefore, it is concluded that these two (2), newly identified special lifting devices are also in compliance with the Phase I guidelines of NUREG-0612 for special lifting devices. As such, it can be stated that the use of these special lifting devices does not increase the probability of occurrence or severity of consequences for an accident previously identified within the NAPS UFSAR, nor does it create the potential for an accident of a different kind.

| 1. Safety Evaluation Number | 2. Applicable Station | 3. Applicable Unit |
|---|---|---|
| 01-SE-MOD-02 | [x] North Anna Power Station<br>[ ] Surry Power Station | [x] Unit 1 [x] Unit 2<br>[ ] Unit 1 [ ] Unit 2 |

**Part A – Resolution Summary Report**

4. List the governing documents for which this safety evaluation was performed.
Plant Issue N2000-2146. RM Letter, Special Report Serial No 01-295, Docket No 50-338, 50-339, License No NPF-4, NPF-7. DCP 99-006, "Replacement of Ventilation Radiation Monitors, NAPS, Units 1 & 2. UFSAR/ISFSI SAR Change Request NO 99-065. Health Physics procedures.HP-3010.040, HP-3010.031, HP PT-453.01, HP PT-456.01. Wiring Verification Procedure 0-NAT-I-002. Emergency Preparedness documents EPIPs 1.01, 4.08, 4.09, 4.24. EALs B-4, B-7, C-7, C -9, E-3, E-5, G-1, G-2. VPAP –2103(N). NSS work procedure 0-WP-G99006. Installation Test Procedure 0-NAT-M-005. TEST PLAN FOR DCP 99-006.

5. Summarize the change, test, or experiment evaluated.

The current KAMAN process and vent stack particulate, iodine and gaseous radiation monitors 1-GW-RM-178, 1-VG-RM-179 & 1-VG-RM-180 will be replaced by radiation monitor system manufactured by MGP Instruments. The currently installed Westinghouse, NRC and General Atomic radiation monitors 1-GW-RM-101/102, 1-VG-RM-103/104 & 1-VG-RM-112/113, currently installed in parallel with, and redundant to the KAMAN monitors, will be removed.

6. State the purpose for this change, test, or experiment.

The new monitors are being installed to replace the KAMAN monitors because the manufacturer has ceased production and support of the monitors. The current Radiation Monitoring System installation, performing redundant functions, is comprised of a parallel combination of different manufacturers' equipment that has been difficult and expensive to maintain and operate. The intent is to replace the current installation with a more flexible, state of the art system.

7. List all limiting conditions and special requirements identified or assumed by this safety analysis. For each item, indicate the formal tracking mechanism that will be used to ensure that these conditions and/or requirements will be met.

The corresponding Westinghouse and General Atomics skids need to be in operation to provide coverage of channel monitoring when the Kaman equipment is being replaced. Work Procedure 0-WP-G99006 will ensure that the Westinghouse and General Atomics are maintained and operable during these periods.

A procedurally controlled jumper will be installed on the process vent radiation monitoring system to enable the process vent automatic control function to be performed by the Westinghouse and General Atomics monitors while the Kaman monitors are being replaced. The replacing MPGI equipment will take over this function. Installation and removal of this jumper will be controlled via Work Procedure 0-WP-G99006.

8. Will the proposed activity/condition result in or constitute an unreviewed safety question, an unreviewed environmental question, a change to the Fire Protection Program that affects the ability of the station to achieve and maintain safe shutdown in the event of a fire, or require a license amendment or Technical Specifications change? [ ] Yes [x] No

**Part A – Resolution Summary Report**

18. Summarize from Part D, Unreviewed Safety Question Determination, the major issues considered; state the reason the change, test, or experiment should be allowed; and state why an unreviewed safety question does or does not exist (a simple conclusion statement is insufficient).

*This 50.59 evaluation includes aspects of 1). the DCP, 2). changes to the UFSAR and 3). the Temporary Modifications.

1). Evaluation of DCP Aspects:

*The Unit 1 & 2 Ventilation Radiation Monitoring (KAMAN) system will be removed and replaced by a system manufactured by MGP Instruments. The currently installed redundant radiation monitors, situated in parallel with KAMAN monitors, will also be removed by this modification. This Design Change Package will be implemented "non-outage". The old equipment, that is, the monitors, samplers, skids, and local instrumentation mounted on the turbine deck and normal switchgear room, and the indicators, recorders, annunciators, controls and electronics in the main control room, will be removed and replaced in phases.

* During the phased replacement of the Kaman equipment, alarm annunciation signals will not be available from the Kaman skids. During this time the readings and associated alarms from the Westinghouse and General Atomic radiation detectors for these vents will be used as a substitute for the Kaman skid signals because they are part of the current radiation monitoring system which monitor the vents in parallel with the Kaman installation. These Westinghouse and General Atomic radiation detectors will be removed at a later phase of the modification.

* Automatic actions are initiated by the process vent RM which, on high radioactivity, open contacts which close the flow control valve GW-FCV-101 from the Gaseous Waste System and close the Containment Vacuum Pump discharge valves (GW-TV-102A&B) to the process vent system. The Containment Vacuum Pumps then stop automatically when their respective TRIP VALVE leaves the full open position. These actions stop the flow from the gaseous waste system and stop the transfer of containment atmosphere to the process vent system, therefore the actions are fail safe. The Westinghouse monitors, 1-GW-RM-101 and 1-GW-RM-102, will provide this control function while the Kaman Monitor 1-GW-RM-178 is being replaced. Once the replacement MGPI monitor 1-GW-RM-178 is installed, it will provide the control function. There are no redundancy requirements associated with this control function therefore there is no need to provide a replacement control signal when the Westinghouse monitors 1-GW-RM-101 and 1-GW-RM-102 are removed.

* The phased replacement will be controlled by NSS work procedure 0-WP-G99006. However, to enhance communication, the necessary actions will be discussed in look ahead meetings and daily meetings, as necessary, between NSS and Operations departments and will have timely placement in the POD. Similar restrictions are currently encountered during normal maintenance of this equipment and are handled by existing station procedures.

* Should any of these Westinghouse/General Atomic skids fail while this replacement is ongoing, Technical Specification, Table 3.3-6, Action 21, concerning fuel movement activities, or Action 35, concerning the identification of preplanned alternate means to provide high range monitoring to meet RG 1.97 requirements, will be in effect. The "B" vent stack Kaman skid replacement will be implemented during periods of no scheduled fuel movement and the preplanned alternate means to provide high range monitoring capability will be implemented by use of the NRC high range gas monitors.

* When the accidents previously evaluated in UFSAR, Chapter 15, Section 15.3.5 were considered, it was seen that the activities during and after the modification will not increase the probability of occurrence of these accidents. The radiation monitoring system monitors ventilation radiation under normal operation and accident conditions but can not, of itself, increase the probability of accidents. During replacement of Kaman skids the loss of alarm annunciation from these skids will be compensated by taking alarm signals from the parallel Westinghouse monitors. Compensatory measures will include increased monitoring of plant parameters for the annunciation lost. Also, for the process vent, Westinghouse monitors will provide the normal automatic control function to operate SOVs while the Kaman system is being replaced. The equipment will be replaced or removed in a sequence that will ensure the necessary monitoring and sampling of variables continues during the modification. Therefore, the probability of occurrence of an accident is not increased and the consequences of an accident are not increased.

* Until a Technical Specification update, not associated with this DCP, is completed later than the DCP, the T.S. units for Stack "B" normal range gas and particulate channels are given as cpm while the units indicated in the control room by the MGPI equipment is microCuries/cc. For the convenience of Operations Department plaques will be mounted adjacent to associated 1-EI-CB-49E indicators giving the necessary microCuries/cc to cpm conversion factor.

**Part A – Resolution Summary Report**

* The Health Physics stack "A" and "B" grab sample stations will be relocated, one at a time, from the current situation in the roof enclosure to elevation 291' 10", where they will be seismically supported and restrained as part of the last phase of this modification. The previously installed MGPI skids will have grab sample stations available that may be used should a grab sample be required while the HP sample stations are being relocated.

* The DCP will replace an existing system with new, state of the art equipment that will perform all the functions of the current system. The replacement radiation monitoring equipment is by a manufacturer with a design different from that used previously for ventilation radiation systems by Virginia Power. Although information on this equipment is not available on the EPIX system, it has been installed in several nuclear plants and is reported to have performed satisfactorily without incident by the manufacturer. The new equipment performs indication, alarm and one control function, in a manner similar to the presently installed system. Should a monitor fail, it will be declared inoperative and measures taken similar to those taken on failure of the currently installed system. It is therefore concluded that this modification to the ventilation radiation monitoring system will not create the possibility for an accident of a different type to that evaluated.

* The DCP does not involve or impact any safety-related equipment or system. On DCP completion, the new equipment will perform the functions of the existing equipment. There are devices, not included in the old skids, which perform functions that will be performed by the new equipment skids. These devices will be removed by this DCP in a phased manner as their functioning is tested and proved.

* This modification will not affect any reactor protection or reactor control circuits, nor will station isolation be affected by the evolution. These radiation monitors will detect, monitor and indicate radiation activities and release rates, including annunciate alarms.

Control activities are limited to those described in the previous paragraphs. The installation of this equipment, monitoring in nature, will not cause an unreviewed safety question to exist, thus the changes required by DCP should be allowed.

2). Evaluation of UFSAR Aspects:
The DBD UFSAR Engineer has requested that the following be text be added on the acceptability of deleted wording in the UFSAR:

Section 11.4.2.1. The original statement was that the entire radiation monitoring system was fail safe. The proposed change removes the condition that the entire radiation monitoring system is "fail-safe" but leaves the statement that it is designed "with emphasis on system reliability and availability". This change is proposed for clarity, but is not considered editorial because of the criteria associated with the term "fail-safe". As used in the radiation monitoring system, it refers to items or criteria such as: reliable power, alternate monitors, loss-of-power indications, independence from other detectors, etc. However, the term "fail-safe" can be associated with more stringent criteria that evaluates all possible failure modes, and requires the component to always fail to the conservative condition. The radiation monitors do not fit this definition. The specifications for the radiation monitors do not require the systems to meet this conservative and rigorous definition of "fail-safe". What the specifications do require leads to reliable and available systems. This proposed text change will, therefore, ensure the UFSAR does not overstate the capabilities or design requirements of the radiation monitoring system. The system Is not required to be fail-safe, therefore such a statement should be removed. This statement should have been corrected at the time of the last UFSAR update. A similar change to Surry's UFSAR was also performed during their IRT review. For these reasons the change of wording of the UFSAR does not cause to be put into effect an unreviewed safety question.
Section 11.4.2.2. The last sentence in this section, pertaining to the particulate monitoring function for the Process vent system, "The sample system is controlled from the control room" is removed. This statement was validated under the UFSAR update effort (ref. ICMP database record identifier #30401) as referring to indications, which are recorded on strip charts located in the control room, and to the local annunciated alarms. This validation record also states that the radiation monitor can be source checked from the control room though this is not stated in this section of the UFSAR. These aspects of the instrumentation are not considered to be elements of control and in fact the new MGPI equipment will no longer have a source check feature nor will sample pump control originate from the control room. This statement is considered superfluous and not applicable to the new equipment, therefore it is deleted. However, the operators still have the capability of monitoring the indication and alarms of the sample system. For these reasons the change of wording in this section of the UFSAR does not invoke an unreviewed safety question.
Section 11.4.2.5. The statements made in this section regarding low sensitivity to changes in background radiation level and low tendency to over respond to different noble gas nuclides, as compared to gamma sensitive detectors, are being removed. These are subjective in nature and do not provide a reference scale or basis by which these statements can be compared and as such are not statements that are relevant indicators of safety of the plant. The statement concerning sensitivity to Kr-85 is retained as it is still applicable to the noble gas detector, though the word "excellent" is removed, as it is subjective in nature and without basis. For these reasons the change of wording in this section of the UFSAR does not invoke an unreviewed safety question. The change in reference to B vent duct size from 84" to 90" is due to utilizing the existing nozzle, which is located in the 90" portion of the vent duct, and which is currently used by the KAMAN vent stack monitors, for the new MPGI equipment. This was done because the GA Technologies monitor associated isokinetic nozzle, located in a portion of the 84" duct, will no longer be used for this function. This function is now performed

**Part A – Resolution Summary Report**

by the MGPI equipment, which uses the original installed nozzle used for the Kaman system. The change of wording in the UFSAR does not invoke an unreviewed safety question.
Section 11.4.3.1.1 statement concerning ANSI 13.1: Although the original isokinetic nozzles and sample tubing up to the existing Kaman monitors are being retained, the reference to ANSI-N13.1 is removed because isokinetic sampling is no longer employed with the new MGPI monitors but rather sample flow is automatically adjusted in proportion to the variances in stack flow. This is still considered to meet the intent of representative sampling described in Regulatory Guide 1.21, and referenced in NUREG-0737, and complies with vendor recommendations which indicated that particulate monitoring is ineffective below 1 scfm. Some questions of UFSAR requirements of representative samples regarding Reg Guide 1.21 are addressed, and satisfactory answers found, in Category 3 Root Cause Evaluation Response N-2001-0071-E1. The change of wording in the UFSAR does not invoke an unreviewed safety question.
Section 11.4.3.1.1 statement concerning built-in response source: The statement concerning the built in response source is no longer applicable with the new monitors as they do not contain check source features. The MGP Instruments monitors on the effluent gas channels perform various self-checks automatically. Their electrical self-check introduces a known and fixed level of pulses into the electronics, excluding the detector, and verifies that the response is correct or a fault is generated. Additionally, the electronics continuously monitors the detector for a minimum count rate otherwise a fault alarm is generated. For these reasons the change of wording in the UFSAR does not cause to be put into effect an unreviewed safety question.

A review has been made of the methodologies used in this DCP, of the implementation of the DCP and of the changes that the implementation of this DCP has had upon the UFSAR. In each case, the probability of occurrence or the consequences of an accident or malfunction of equipment important to safety previously evaluated in the safety analysis report will not be increased. Also, the possibility for an accident or malfunction of a different type than any evaluated previously in the safety analysis report will not be created and the margin of safety as defined in the basis for any technical specification will not be reduced.

3). Evaluation of TM Aspects:

There are two temporary modifications involved in this DCP. 1) A temporary rack will be located adjacent to the Effluent Monitoring Panel and 2) A temporary jumper will be placed to allow the control function of the Process vent monitor to remain continuously available during Kaman skid replacement.

*To accommodate the necessary phased replacement of the currently installed system, a temporary modification is required which places a temporary rack adjacent to the existing effluent control panel in the control room. The existing control panel components will be relocated to the temporary rack and tested before being returned to service thus enabling phased location of the new equipment. The layout and location of the temporary rack is given in DCP drawings, and the associated requirements communicated to Operations department via NSS procedure 0-WP-G99006.

* A second temporary modification is required in which the Kaman skid relay contacts providing the control signal for the waste gas decay tank and containment vacuum pump releases is replaced by a temporary jumper. This modification will be procedurally controlled by NSS work procedure 0-WP-G99006. The jumper will replace the normally closed contacts provided by the Kaman skid. Administrative control of this modification will not be required because this function will continue to be performed via the Westinghouse particulate and gas detectors' series circuit contacts on a high radiation signal. Following MGPI skid installation and testing, the temporary jumper and Westinghouse monitors will be removed.

* It should be noted that the sample lines from stack A and B vents will be opened to allow isolation valves to be installed. Plugs will be available, at the sites of line openings, for use in blocking the sample flow paths should an increase in effluent activity occurs. The use of these plugs is controlled by Work Procedure, 0-WP-G99006.

* The test department will confirm that the temporary rack and jumper are located in accordance with design criteria. Test department and I&C department will use the applicable installation, wiring and calibration procedures to demonstrate operability of the circuits prior to the modifications being put into service and after each temporary modification is removal. Control and testing shall be via NSS work procedure 0-WP-G99006.

* Compensatory measures and contingency plans will be taken to ensure that during the installation of these modifications alternate methods of indication and control are available ensuring that total functionality is unchanged. The functionality of the new equipment is as the old with the indication, alarm and control functions are as before DCP implementation. The equipment is considered to be more reliable, thus have a lower failure rate that the equipment being removed.

* It is therefore concluded that the above measures and plans, implemented by procedure, ensure that these modifications to the ventilation radiation monitoring system will be implemented without constituting an unreviewed safety question.

| S.E. # | Unit | Document | System | Description | Date |
|---|---|---|---|---|---|
| 00-SE-MOD-12 **REV. 2** | 1,2 | DCP 99-010, F. C. 2<br>UFSAR FN 00-036 | SW | F. C. 2 extends the time for operation of the charging pumps on the intermediate configuration from the end of April to May 10. | 4-10-01 |
| 00-SE-MOD-19 **REV. 1** | 1,2 | DCP 00-004<br>UFSAR FN 99-032<br>0-OP-49.7 | SW | Rev. 2 in for a chg in 0-OP-49.7 (not the DCP) – states that alarm indications on MCR vertical board associated with open position of 1-SW-MOV-120B & 2-SW-MOV-220A will be temporarily removed. If temporary (< 72 hours) interruption of the blowdown is required, it may be done by closing 2-SW-MOV-120B or 2-SW-MOV-220A, or 1-SW-1351 or any combination of the above valves. | 4-12-01 |
| 99-SE-MOD-08 **REV. 2** | 2 | DCP 99-001, F. C. 1<br>2-OP-1.3, 2-OP-3.3, 2-OP-15.2<br>1-OP-26.8 | | Rev. 2 modifies the requirement of maintaining 2 one-inch drain valves tagged open as described in Rev. 1 to maintaining at least one shellside drain per MSR open during shutdown, which will be an indicator of water in the MSR. | 3-22-01 |
| 00-SE-OT-13 **REV. 2** | 1,2 | QA Topical / UFSAR Chg FN 00-04B | | Rev. 2 incorporates latest NRC comments: Changes the retention requirements for fuel from Lifetime$^{(a)(3)}$ to Lifetime$^{(a)(1)}$ plus 3 years after the transfer of fuel. | 2-06-01 |
| 00-SE-OT-13 **REV. 3** | 1,2 | QA Topical / UFSAR Chg FN 00-04C | | Rev. 3 incorporates latest NRC comments: Changes the retention requirements for fuel from Lifetime$^{(a)(3)}$ to Lifetime$^{(a)(1)}$ plus 3 years .<br>Supersedes FN 00-04B package, which contained a misleading retention requirement. | 2-15-01 |
| 00-SE-OT-31 **REV. 1** | 1,2 | UFSAR 00-027<br>UFSAR 00-027A<br>TS Chg #375 | | Rev. 1 corrects an oversight in UFSAR change FN 00-027, i.e., failure to reflect the revised cold-to-hot leg recirculation switchover interval previously evaluated in 00-SE-0T-31, Rev. 0. Also corrects a typo in the revision number of Reference 6 in Question 18. | 6-21-01 |
| 00-SE-OT-60 **REV. 1** | 1,2 | TS CHG 376A<br>UFSAR FN 00-048<br>TSCR 376B | | Rev. 1 incorporates revised P/T limit curve data applicable to heatup to address a Westinghouse computer code error. | 3-20-01 |
| 99-SE-PROC-22 **REV. 1** | 1,2 | 1-OP-10.2 (R.5-P1)<br>1-OP-10.2 (R. 8-P1) | | Rev. 1 allows connecting 2 suction hoses & 2 discharge hoses to the temporary air operated pump to allow a higher flowrate. | 3-30-01 |
| 00-SE-TM-03 **REV. 1** | 1,2 | TM N1-1681 – Rev. 1 | SW | The PRV (1-SW-RV-102) providing protection to 1-SW-TK-2 will need to have its set pressure lowered to 115 psig due to the projected thinning rate of the tank's wall thickness. | 5-25-01 |

**00-SE-MOD-12, Rev. 2**

**Description**
DCP 99-010, Replacement of Service Water lines to/from Charging Pumps and Instrument Air Compressors, and UFSAR Change Request No. FN 2000-036

**Summary**
The scope of the design change includes replacement and modification of deteriorated four-inch diameter carbon steel (CS) and stainless steel (SS) service water (SW) headers and adjacent SW piping to/from charging pumps (CP) and instrument air compressors (IAC) with high corrosion resistant alloy AL-6XN. Investigation (Calculation ME-0586) shows that adequate supply of SW to the CP and IAC can be achieved utilizing one pair 4" diameter SW headers (four 4" diameter lines) instead of the existing two pairs of headers (eight 4" diameter lines). This will simplify the existing piping layout and will cost less than a one to one replacement.

This SW piping replacement and modification does not involve unreviewed safety questions since replacement of the deteriorated CS with 316L SS piping with 6% Mo stainless alloy is replacement of the existing piping with superior quality (higher stress allowables and corrosion resistance ) material. Therefore, the long term consequences of this replacement will increase reliability of the SW system. The intermediate and final stages of the modification satisfy redundancy and flow rate requirements for all modes of operation. No changes to the Operating Licenses or Technical Specification are required.

Basic SWS functions are not altered as a result of this piping upgrade. The SW piping configuration to/from charging pumps and IA compressors will be simplified. The existing complex piping is the result of multiple repairs and replacement since the original construction. This upgrade will not adversely affect the basic functions of the SW system and will not create an accident of a different type than was previously evaluated in the UFSAR. Replacement of the deteriorated SW piping with superior material will increase reliability of the SW system. Therefore, the possibility for an accident of a different type than previously evaluated in the Safety Analysis Report will not be created.

Calculations ME-0582, 0586 show that required flow rates to the charging pumps and IACs will be satisfied for the design basis range of SW temperatures during the temporary arrangement. However, there is a very small margin on SW flow rate to the non safety-related IACs during maximum design SW temperature during the temporary piping arrangement. To increase the margin, transfer charging pumps to final arrangement will be planned during a time period between October to May 10 when expected temperature in the SW reservoir will be below 85°F. This will increase flow to IACs during summer weather conditions and allow transferring IACs to final piping arrangement during the summer weather.

**00-SE-MOD-19, Rev. 1**

**Description**
DCP 00-004, Service Water (SW) Blowdown
UFSAR Change FN 99-032
Procedure 0-OP-49.7

**Summary**
The scope of the design change include the design of a SW blowdown line with a capacity of approximately 900 gpm. The existing SW discharge path (lines 24"-WS-C42-151-Q3 and 24"-WS-C43-151-Q3 to the Unit 2 circulating discharge tunnel, outfall 108) will be used.

Implementation of the proposed SW blowdown does not involve an unreviewed safety or environmental question since:

1. The probability of the SW Design Basis Accident does not increase (LOCA on one Unit with simultaneous LOOP on both Units) since SW cannot be a LOCA or LOOP initiating event. The basic functions of the SW System are not altered and SW will be provided to all accident cooling loads in accordance with the original design as described in the UFSAR. The consequences of a DBA are not increased.
2. The 30-day inventory for the SW System will be preserved. There is a small chance that in case of SW DBA the operating safety-related screen wash pump may become inoperable due to failure of corresponding diesel. In this event, SW inventory may be losing 900 gpm due to uncompensated blowdown. Operator action will be required to close one out of two MOVs (2-SW-MOV-220A or 1-SW-MOV-120B) or manual valve 1-SW-1351 to terminate the blowdown. Calculated allowable time for this action, based on 900 gpm blowdown rate and maximum drift, is 45 hours (calculation ME-0605) from the initiation of the event. The conservatively established time for these manual actions (closing one out of three valves) is 30 hours from the initiation of the event. Note, that from the standpoint of safety a blowdown flow rate of 1400 gpm is acceptable to allow for a 30 hour isolation time in the event of a makeup loss.
3. The malfunction of equipment important to safety previously evaluated in the safety analysis is not increased. Three valves for isolation of the blowdown, as described above, are provided. Other equipment in the SW system is not affected. Constant alarm indication on the main control room vertical board associated with open position of valves 1-SW-MOV-120B and 2-SW-MOV-220A will be temporarily removed for the duration of the blowdown evolution. This is acceptable as it preserves the blackboard concept of alarm panel on the main control board while maintaining capability for other valves.
4. The probability of an accident or a malfunction of a different type than previously evaluated in the Safety Analysis Report is not created. Although a new flow path and manual actions are introduced, the actions, times and controls are consistent with the existing SW operations. The possibility of operator error resulting in the inadvertent opening of the 24" SW overboard valves will be eliminated by de-energizing the valves in the closed position, therefore the blowdown will be possible only through the 6" line. The operator allowable time to close one out of three valves in the blowdown path (two of them are safety-related MOVs supplied from different safety-related busses) was calculated as 45 hours after the initiation of a DBA. Note that 30 hours was conservatively established to close one out of three valves.
5. The margin of safety of any part of the Technical Specifications as described in the basis section will not be reduced since operation of the SW system will not be adversely affected and the 30-day cooling water supply will be preserved by maintaining the reservoir level between 314'-0" and 315'-0", more than one foot above the minimum Technical Specification SW reservoir level of 313'-0". Calculated allowable time for operator action is 45 hours.
6. The discharge of the SW reservoir to Outfall 108 is currently included in the VPDES permit. This discharge has been analyzed and is an approved discharge path. Additionally, no significant change in radiological effluents is expected since the SW system does not contain fission by-products. If a RSHX tube leak were to occur concurrent with a CDA with the overboard flowpath open, procedural guidance would isolate the flowpath after receipt of a radiation alarm.

**99-SE-MOD-08, Rev. 2**

**Summary**
DCP 99-001, Moisture Separator Reheater (MSR) Replacement
Procedures: 2-OP-1.3, 2-OP-3.3, 2-OP-15.2, 1-OP-26.8
Field Change #1 to DCP 99-001

**Description**
The existing MSRs (2-MS-E-1A, -1B, -1C, -1D) will be removed in their entirety (tube bundles and shells) and replaced with new MSRs. Field Change #1 to DCP 99-001 raises the allowable MWe limit on the main generator.

The accidents previously considered in the Safety Analysis Report, and applicable to MSR replacement, are Main Steam Line Breaks and minor secondary system pipe breaks. The new MSRs utilize Main Steam (MS) from the MS header to heat the high pressure turbine exhaust ateam. Although portions of the MS system are safety-related, the MS header and supply lines to the MSR are not. The new MSRs will be designed, built, and tested in accordance with Section VIII, Div 1 of the ASME Boiler and Pressure Vessel Code, and will be installed in accordance with approved station procedures. Accordingly, the integrity of the MS system piping associated with the MSRs will not be adversely affected. The replacement of the MSRs will not increase the probability of occurrence or consequences of the accidents identified above.

The malfunctions of equipment related to safety, previously evaluated in the Safety Analysis Report, and applicable to MSR replacement, are Main Steam Trip Valve malfunction and MS Line Breaks. The MSRs are non safety and are supplied with steam from a non safety-related portion of the MS system, downstream of the MS Trip Valves. Therefore, replacement of the MSRs will not increase the probability of occurrence or consequences of the malfunctions identified above.

Replacement of the MSRs will not create the possibility for an accident or malfunction of a different type than was previously evaluated in the Safety Analysis Report. The new MSRs will perform the same function as the existing (i.e., use a portion of the MS flow to reheat the high pressure turbine exhaust steam), and will utilize existing piping connections. All existing instrumentation and control components will remain functional and unchanged. The new MSRs will be designed, built, and tested in accordance with Section VIII of the ASME Boiler and Pressure Vessel Code for operation in the full range of design basis conditions for the MS system. With the exception of the higher thermal efficiency and FAC resistance, the new MSRs are essentially a like-for-like replacement.

The MSRs and associated piping and instrumentation are not required for safe shutdown of the unit, accident mitigation, safe shutdown capability, or compliance with the Technical Specifications. No change to the Operating License will be required. An increase of 10Mwe, and the associated changes in steam and condensate flows, will not affect the Final Environmental Statement or the ISFSI.

**00-SE-OT-13, Rev. 2**

**Summary**
QA Topical Report/UFSAR Chapter 17 Change FN 2000-04B - Incorporate additional NRC comments into UFSAR/QA Topical Report change

**Description**
The purpose of the change is to reduce the length of time records are being maintained for documenting quality activities. This package incorporates the latest NRC comment into the package. In order to address the NRC concern the retention requirement for fuel is being changed from Lifetime[(a)(3)] to Lifetime[(a)(1]) plus three years after transfer of fuel. This will address the NRC interpretation of the requirements of 10 CFR 71.135, Quality Assurance Records.

The Operational QA Program change does not affect the operation or design of the plant or any system, structure or component. No accident analysis assumptions are modified or challenged by this change. Plant equipment will not be operated in a different manner. This change is administrative in nature and redefines the record retention requirements, clarifies the definition of a QA Record, and establishes Lifetime as a record retention period. Therefore, this proposed Operational QA Program change will not:

- Increase the probability of occurrence or consequences of any accident or malfunction of equipment important to safety previously analyzed in the SAR
- Create an accident or malfunction of equipment of a different type than was previously evaluated in the SAR
- Reduce the margin of safety as defined in any Technical Specification Bases.

**00-SE-OT-13, Rev. 3**

**Summary**
QA Topical Report/UFSAR Chapter 17 Change FN 2000-04C - Incorporate additional NRC comments into UFSAR/QA Topical Report change and corrects a proposed misleading retention requirement in the B package.

**Description**
This package incorporates the latest NRC comments. In order to address the NRC concern the retention requirement for fuel is being changed from Lifetime[(a)(3)] to Lifetime[(a)(1)] plus three years. This will address the NRC interpretation of the requirements of 10 CFR 71.135, Quality Assurance Records, which requires the licensee to retain records for 3 years beyond the date when the licensee last engages in the licensed activity. This package supercedes the "B" package, which contained a misleading requirement for the record retention requirements for fuel.

The Operational QA Program change does not affect the operation or design of the plant or any system, structure or component. No accident analysis assumptions are modified or challenged by this change. Plant equipment will not be operated in a different manner. This change is administrative in nature and redefines the record retention requirements, clarifies the definition of a QA Record, and establishes Lifetime as a record retention period. Therefore, this proposed Operational QA Program change will not:

- Increase the probability of occurrence or consequences of any accident or malfunction of equipment important to safety previously analyzed in the SAR
- Create an accident or malfunction of equipment of a different type than was previously evaluated in the SAR
- Reduce the margin of safety as defined in any Technical Specification Bases.

**00-SE-OT-31, Rev 1**

**Description**

- Technical Specification Change Request #375
- UFSAR Change Request FN-2000-027
- UFSAR Change Request FN-2000-027A

The current Technical Specifications requirements specify that the refueling water storage tank (RWST) and the casing cooling tank (CCT) be at a concentration between 2300 and 2400 ppm and the safety injection accumulators (SIAs) be at a concentration between 2200 and 2400 ppm. The boron concentration of the spent fuel pool (SFP) is not explicitly stated in the Technical Specifications. This change will increase the boron concentration limits in the RWST, CCT, and SFP to 2600 – 2800 ppm and to 2500 – 2800 for the SIAs. The boron concentration of the SFP is being increased to keep the boron concentration consistent with the refueling canal and all portions of the reactor coolant system during refueling.

*Revision 1 corrects an oversight in UFSAR Change Request FN 2000-027 (i.e., failure to reflect revised cold-to-hot leg recirculation switchover interval previously evaluated in 00-SE-OT-31, Revision 0). A typo in the revision number of Reference 6 (SM-415, Rev. 2) on Question 18 (supplemental page 2D) was corrected. In addition, Revision 1 uses a revised 50.59 form (June 2000). Other than these changes 00-SE-OT-31, Revision 1 is identical to 00-SE-OT-31, Revision 0.*

**Summary**

This change involves increasing the boron concentration in the refueling water storage tank (RWST), casing cooling tank (CCT), and the spent fuel pool (SFP) from the current Technical Specification limits of 2300 – 2400 ppm to 2600 – 2800 ppm and from 2200 – 2400 ppm to 2500 – 2800 ppm for the safety injection accumulators (SIAs).

It has been the Company's outage planning philosophy to stagger outages whenever possible in order to avoid load management, logistical, and economic disadvantages associated with concurrent outages. In order to accommodate this outage planning philosophy, the fuel management plan for each unit provides for flexibility in the final end-of-cycle burnup including the use of power and RCS average temperature (Tavg) coastdowns.

While end-of-cycle coastdowns are fully evaluated from a safety analysis perspective, they represent an off-nominal operational mode that is undesirable from the standpoint of maximizing electrical generation. Designed reload cores with increased initial core reactivity is one means to reduce the need for extended end-of-cycle coastdowns. Increased core reactivity will require higher boron concentrations than previous cycles to meet increased shutdown requirements. One of the limiting parameters for core designers is the post-LOCA sump boron concentration limit. Increasing the boron concentration in the RWST, CCT, SIAs, and SFP will remove one obstacle currently preventing longer full power cycles.

Therefore, more reactive cores will reduce the duration of T-avg and power coastdowns, resulting in more energy production. Wider control bands on boron concentration limits will also provide greater operational flexibility.

**Safety Significance**

The following evaluations were performed to assess the impact of the proposed Technical Specification changes:

- Non-LOCA transients were evaluated, and it was determined that only the boron dilution event was potentially affected by the proposed increased boron concentrations.

- The effects of increased boron concentrations in LOCA evaluations were also considered. The time to switchover from cold to hot leg recirculation for long-term cooling following a loss of coolant accident

(LOCA) was analyzed to determine the impact of the increased boron concentrations. The post-LOCA sump boron concentration limit was recalculated to ensure adequate post-LOCA shutdown margin. The post-LOCA containment sump and quench spray (QS) pH were calculated with an increased boron concentrations in the RWST, CCT, and SIAs to ensure that the pH remains within acceptable limits.

- Other evaluations, such as boron solubility, equipment qualification, and RWST and boric acid storage tank requirements were reviewed to ensure that a higher boron concentration does not adversely impact the safe operation of the plant.

These evaluations revealed that increased boron concentration limits in the RWST, CCT, SIAs, and SFP generally provide an analytical benefit from a reactivity management and accident mitigation standpoint. Potential adverse effects in the boron dilution event are accommodated in the reload verification process (Reference 2). The pH limits specified in the Standard Review Plan (Reference 1) continue to be met with increased boron concentration limits. The time interval for switchover from cold-to-hot leg recirculation to avoid boron precipitation in the vessel has been recalculated, and will be implemented upon approval of the increased limits. The increased boron concentration limits cause no adverse effects on the environmental qualification of equipment in the containment. A detailed discussion of these safety considerations is presented below.

Non-LOCA Chapter 15 Transients

Of the non-LOCA transients, only the results of the Boron Dilution accident analysis were found to be potentially adversely affected by the proposed increased boron concentrations. The adverse effect is a result of the increased RCS boron concentrations that would become feasible with the increased RWST boron concentration. The other non-LOCA transients were either not impacted or were made less severe as a result of the increased boron concentrations. For example, an increased boron concentration in the RWST and, hence, in the safety injection system, would provide less limiting Main Steamline Break analysis results. The Startup of an Inactive Loop accident analysis is insensitive to the refueling boron concentration, since this accident is precluded by Technical Specification requirements governing loop stop valve operations.

The Boron Dilution event at Refueling, Cold Shutdown, Intermediate Shutdown, and Hot Shudown conditions is precluded by administrative lock-out of the primary grade water flow path in accordance with North Anna Units 1 and 2 Technical Specification 3.1.1.3.2. However, the Boron Dilution at Startup and at Power analyses are potentially impacted by the proposed increased RWST boron concentration. The impact on the Startup and At Power scenarios is indirect, and is a result of the increased allowable critical RCS boron concentrations resulting from the increased RWST boron concentration. An increased RCS boron concentration is explicitly considered in reload evaluations of the boron dilution event at startup and at power scenarios. As required by the current analysis of record, the reload evaluations of the Boron Dilution at Startup and at Power ensure that at least 15 minutes are available for corrective operator action between positive indication of a dilution in progress and complete loss of shutdown margin.

As previously indicated, the proposed increased boron concentrations can result in increased critical boron concentrations, which would result in higher reactivity insertion rates during a boron dilution event. The Departure from Nucleate Boiling (DNB) effect of these increased reactivity insertion rates were also considered, and were determined to be easily bounded by the rod withdrawal at power analysis. Therefore, the DNB acceptance criterion for the boron dilution event continues to be met.

Large Break LOCA

The effect of increased boron concentrations on the LOCA transient analysis was considered for both the large and small break scenarios. The large break LOCA is characterized by a rapid depressurization that causes the generation of significant voiding in the RCS. In accordance with Appendix K, the docketed North Anna LBLOCA analysis does not assume control rod insertion. As a result, heat generation in the core is reduced to decay heat levels by negative void reactivity. Therefore during the blowdown phase of the LBLOCA the core is shutdown and remains shutdown due to void reactivity.

The refill/reflood portion of the injection phase begins with the highly voided core and continues from downcomer refill through core reflood. During this time, void reactivity is of primary importance at the start and gradually begins to be replaced by boron as the primary source of negative reactivity. The docketed North Anna LBLOCA analysis shows that the peak clad temperature is reached prior to the time the boron becomes significant in maintaining core shutdown. In fact, boron concentrations are not modeled in peak clad temperature cases. Therefore, the increased boron concentration has no effect on the calculated results for the LBLOCA and would in fact provide a benefit if accounted for in the analysis. The proposed increase in RWST and SIA boron concentrations provides additional unmodeled conservatism.

Small Break LOCA

The small break LOCA (SBLOCA) analysis falls into the category of those transients that cause safety injection actuation. The small break LOCA model assumes the insertion of control rods in the calculation of core shutdown. Consequently, the boron concentration required to achieve the level of negative reactivity necessary to assure shutdown for the small break LOCA is significantly lower than the concentration required to assure shutdown for a large break LOCA. The increase in RWST and SIA boron concentration provides additional conservatism for the small break LOCA.

Cold-to-Hot Leg Recirculation Switchover Time

Following a LOCA, borated water from the RWST and accumulators enters the core region through the cold leg during the injection phase of the transient. Assuming a cold leg break, borated coolant enters the core region from the intact cold leg, down the downcomer, and into the core. Steam exits through the hot leg, and excess safety injection water spills out the break. Although the water vapor exits the core and condenses in the containment, only a small fraction of the dissolved boron is carried off in the steam. Therefore, the concentration of boron increases over time in the reactor vessel. If the boron concentration reaches the solubility limit, boron will begin to precipitate out of solution, forming a sticky paste that can block the coolant flow channels in the core. Such a condition may lead to inadequate cooling of the fuel.

If the break is in the hot leg or in the pressurizer, safety injection water will flow down the downcomer, up through the core, and out the break, thereby continuously replacing the boric acid solution in the core region. In such a situation, switchover to hot leg recirculation is not necessary. However, there is no unambiguous way to locate the pipe break from the control room, so switchover from cold leg to hot leg injection is required at a specific time for all LOCAs.

Because of the proposed boron concentration increase, the recirculation switchover time must occur sooner to avoid boron precipitation in the reactor vessel. The currently accepted boron precipitation limit is 23.5 weight percent boron, which includes a four weight percent safety margin to account for uncertainties. With a RWST and CCT boron concentration between 2600 – 2800 ppm and a SIA boron concentration between 2500 – 2800 ppm, a 5.26 hour switchover time has been calculated (Reference 4). For convenience, a 5 hour switchover time will be implemented, replacing the 7 hour time to prepare for switchover and the 10 hour switchover time currently in the North Anna Emergency Operating Procedures.

A potential issue was raised by Westinghouse concerning the possibility of inadvertent recriticality following switchover from cold leg to hot leg injection (Reference 9). The accumulation of boron in the reactor vessel following a large break LOCA, and prior to cold-to-hot leg switchover, results in a decrease in the sump boron concentration. Westinghouse postulates that switchover from cold leg to hot leg injection may wash out the concentrated boric acid in the core region, and replace it with the sump fluid which is depleted in boric acid. If the reduction in sump boron concentration during cold leg injection is sufficient, the cold-to-hot leg switchover may result in inadvertent re-criticality. This issue has been addressed by developing a Reload Safety Analysis Checklist (RSAC) parameter that ensures that the sump boron concentration and xenon reactivity at the time of cold-to-hot leg switchover is adequate to keep the reactor subcritical.

Post-LOCA Sump Boron Concentration Limit

Following a Small or Large Break Loss of Coolant Accident (SBLOCA or LBLOCA), fluid from various volumes accumulate in the containment sump. At North Anna, these volumes include the RWST, the chemical addition tank (CAT), the SIAs, the safety injection system piping (SI Piping), the reactor coolant system (RCS), the boron injection tank (BIT) and the CCT. All of these volumes contain boric acid solution with the exception of the CAT, which contains a sodium hydroxide solution. Depending on the magnitude of the loss of coolant accident (LOCA), some or all of the liquid contained in these volumes will be introduced to the containment, and will ultimately accumulate in the containment sump. It is assumed in the sump boron analysis for the design basis LBLOCA, that all of the liquid in these volumes is transferred to containment.

It is necessary to have a sufficiently high boric acid concentration in the sump mixture to ensure that the reactor remains subcritical. As more reactivity is loaded into the core, increased amounts of boron are required. The post-LOCA sump boron concentration limit for an increased boron concentration of 2600 to 2800 ppm in the RWST and CCT has been recalculated and will be incorporated into the Reload Safety Analysis Checklist (RSAC) (Reference 2) upon approval of the boron concentration increase (Reference 5).

Post-LOCA Sump and Quench Spray pH Limits

Limits are placed on the containment sump and QS pH because of material considerations and to reduce the evolution of iodine from the liquid. A post-LOCA sump pH range of 7.0 to 9.5 is specified in the Standard Review Plan (SRP) to avoid to onset of stress corrosion cracking (Reference 1). A pH range from 8.5 to 10.5 is specified in the SRP (Reference 1) to minimize the evolution of iodine during post-LOCA operation of the containment spray system.

The pH of the post-LOCA sump is determined by a volume-weighted average of the boric acid and sodium hydroxide concentrations from each analyzed volume. Because the data table used to interpolate the pH assumes that boric acid and sodium hydroxide concentrations are expressed as molarities (moles solute per liter), each volume's concentration (weight percent) is converted to a molarity prior to mixing the contents of the individual volumes in the sump.

The pH of the QS is calculated on the basis of the molarity and volumetric flow rate of liquid drawn from the RWST and CAT into the QS pump suction. The molarity of the RWST and CAT solutions is a simple conversion based on the weight percentage of the solute in the solution, and the specific gravity of the solution.

After consideration of the proposed increased RWST, CCT, and SIA boron concentrations, the post-LOCA containment sump and QS pH continue to meet the acceptance criteria (i.e., post-LOCA sump pH must be greater than 7.0 and less than 9.5 and the QS pH must be greater than 8.5 and less than 10.5) (Reference 6).

Boron Solubility

A boron concentration of 2800 ppm does not approach the solubility limit at the temperatures of the RWST. The temperature of the RWST fluid is limited to between 40 °F and 50 °F in Technical Specification 3.5.5. Figure 6.3-18 of Reference 3 shows that a boron concentration of about 2.5 weight percent boron (~4370 ppm) remains soluble at temperatures above 32 °F (Reference 3).

Equipment Qualification

Chemical spray is one of the environmental factors used to qualify the class 1E electrical equipment to assure operation when required. For the North Anna units, this environmental factor is considered for equipment inside containment experiencing a LOCA environment. There are two sources of chemical spray: quench spray and recirculation spray. The quench spray takes borated water from the RWST and a NaOH solution from the chemical addition tank (CAT). The recirculation spray system takes suction from the containment sump.

Increasing the boron concentration to 2600 – 2800 ppm in the RWST and CCT and to 2500 – 2800 ppm in the SIAs will not adversely affect the environmental qualification of equipment in the Equipment Qualification Master List (EQML). The corrosive agent in chemical spray is primarily NaOH. Increasing the boron concentration lowers the solution pH making it less corrosive (more neutral). Therefore, higher boron concentration limits are acceptable, even for those components qualified at a lower boron concentration (Reference 7).

RWST and Boric Acid Storage Tank (BAST) Volume Requirements

Technical Specification Bases 3/4.1.2 requires that the boration capability of the RWST and the boric acid storage tank (BAST) be sufficient to provide a 1.77%Δk/k shutdown margin from end-of-cycle (EOC) hot full power conditions after xenon decay and cooldown to 200 °F. Furthermore, the same shutdown margin must be maintained after cooldown from 200 °F to 140 °F.

The volume requirements are calculated by determining the reactivity required to achieve cooldown to either 200 °F from HFP or to 140 °F from 200 °F. The volume required to achieve this concentration is determined by converting the required reactivity by a differential boron worth. The required reactivity is determined in a conservative fashion by adding the temperature defects, xenon reactivity, and shutdown margin. A simple mixing model is used to determine the volume of RWST and BAST volume needed to achieve the required boron concentration in the vessel (Reference 8).

As part of this evaluation, Reload Safety Analysis Checklist (RSAC) parameters have been developed in order to ensure the BAST requirements are met on a cycle to cycle basis. The revision and incorporation of RSAC parameters is included in the Technical Specification Change Action Plan.

Based on the above evaluation, the proposed changes to the RWST, CCT, SIA, and SFP boron concentration do not adversely affect the safe operation of the plant.

Transition Consideration for Use of Opposite Unit's RWST

Upon increasing the boron concentration limits for the first unit, and prior to implementing the increased concentrations in the second unit, charging header cross-connect will allow flow from the opposite unit's RWST which will be at a higher or lower boron concentration than the accident unit. Accidents requiring flow from the opposite unit's RWST are outside of the design basis and therefore not formally analyzed. However, use of the cross-connect in beyond design basis events (loss of all injection flow from the accident unit, for example) will continue to be effective (that is, water of slightly lower boron concentration but high with regard to SDM requirements is preferable to no water, for instance). Therefore no changes to the procedural guidance for RWST/charging header cross-connect is required for this change.

Summary

1. Increasing the boron concentration limits for the RWST, CCT, SIAs, and SFP will not increase the probability of occurrence of any known accident and does not adversely affect the safe operation of the plant. Appropriate design constraints were analyzed for changes to T.S. 3.1.2.7, 3.1.2.8, 3.5.1, 3.5.5, 3.6.2.2, 3.9.1, and Bases 3/4.1.2 and 3/4.9.1 and none were found to be more limiting than currently documented in the UFSAR.

2. Increased boron concentration limits for the RWST, CCT, SIAs, and SFP will not increase the consequences of any accident previously evaluated in the Safety Analysis Report. The increased boron concentration limits reduce the time to switchover from cold to hot leg recirculation, which will prevent boron precipitation in the reactor vessel following a LOCA. A reduced switchover time will be implemented in the EOPs as part of the Technical Specification Implementation Plan. The post-LOCA sump boron concentration limit is revised to ensure adequate post-LOCA shutdown margin. The post-LOCA containment sump and quench spray (QS) pH remain within the limits specified in the Standard Review Plan. All other transients either were not impacted or were made less severe as a result of the increased boron concentrations. Therefore, accident analysis results meet all design criteria as stated in the UFSAR.

3. The proposed boron concentration increases do not add new or different equipment to the facility, nor do they significantly change the manner that installed equipment is being operated. There are no changes to the methods utilized to respond to plant transients and no alterations to the way that the plant is normally operated. The proposed UFSAR and Technical Specification changes do not alter instrumentation setpoints that initiate protective or mitigative actions. As a result, no new failure modes are being introduced. Therefore, the possibility for an accident of a different type than was previously evaluated in the SAR is not created.

**00-SE-OT-60 Rev 1**

**Description**

Technical Specification Change Request No. 376A (Supplement to TSCR 376)
UFSAR Change Request FN 2000-048 (Supersedes FN 2000-016)
TSCR 376B (Supplement to TSCR 376 and TSCR 376A)
A supplement to Technical Specification Change Request (TSCR) No. 376 (TSCR 376A) and a revised UFSAR Change Request (FN 2000-048) are needed to address an NRC request for additional information (RAI) on TSCR 376. The NRC has requested consideration of pressure and temperature measurement uncertainties in the proposed revised design basis Reactor Coolant System (RCS) Pressure/Temperature (P/T) Operating Limits, Low Temperature Overpressure Protection System (LTOPS) Setpoints, and LTOPS Enable Temperatures. The NRC has requested inclusion of instrument uncertainties in order for them to grant an exemption to the requirements of 10 CFR 50 Appendix G to permit utilization of ASME Section XI Code Case N-640 (use of the Appendix A $K_{Ic}$ fracture toughness curve, Figure A-4200-1). This safety evaluation also supports a reduction in the Units 1 and 2 reactor vessel head bolt-up temperatures from 90°F to 60°F.
Revision 1 incorporates revised P/T limit curve data applicable to heatup to address a Westinghouse computer code error.

**Summary**
**PURPOSE**

**Note to reader: Revision 1 changes are presented in bold throughout the document.**

This safety evaluation supports Technical Specification Change Request 376A and 376B, which supplement TSCR 376 (2). TSCR 376 and TSCR 376A propose revisions to the Technical Specifications to implement revised design basis analyses for the North Anna Units 1 and 2 Technical Specification Reactor Coolant System (RCS) Pressure/Temperature (P/T) operating limits, Low Temperature Overpressure Protection System (LTOPS) setpoints, and the LTOPS enable temperature ($T_{enable}$). TSCR 376A addresses an NRC Request for Additional Information (RAI) requiring incorporation of margin to accommodate pressure and temperature measurement uncertainties in the P/T limits and LTOPS setpoints. **TSCR 376B provides corrected RCS P/T limit curves applicable to heatup to address a Westinghouse computer code error.** This safety evaluation also supports implementation of a revised reactor vessel head bolt-up temperature. Although the revised reactor vessel head bolt-up temperature does not require NRC review and approval for implementation, this change will be implemented as part of the TSCR 376A Action Plan.

**DISCUSSION**
**TSCR 376A**

A Technical Specification Change Request (TSCR) concerning the North Anna Units 1 and 2 RCS pressure/temperature (P/T) limits and low temperature overpressure protection system (LTOPS) setpoints was submitted to the NRC on June 22, 2000 (2). The basis for this TSCR is described in Reference (3). The objective of the submittal was to justify continued use of the existing Technical Specification P/T limits and LTOPS setpoints on the basis of a margin assessment. The margin assessment required an exemption to the requirements of 10 CFR 50 Appendix G to permit application of ASME Section XI Code Case N-640. N-640 supports use of the ASME Section XI Appendix A $K_{Ic}$ fracture toughness curve (Figure A-4200-1), instead of the ASME Section XI Appendix G $K_{Ia}$ curve (Figure G-2210-1) that was employed in the development of the existing Technical Specification P/T limits and LTOPS setpoints. During a November 7, 2000 teleconference, NRC staff indicated that application of margin to accommodate pressure and temperature measurement uncertainties would be required in order for this exemption request to be granted. Therefore, it became necessary to supplement the Reference (2) submittal with an evaluation of the effects of incorporating pressure and temperature measurement uncertainties into the proposed design basis P/T limits.

As demonstrated in Reference (1), the existing Technical Specification LTOPS setpoints remain conservative and valid to 32.3 EFPY and 34.3 EFPY for North Anna Units 1 and 2, respectively, after application of pressure and temperature measurement uncertainties to the LTOPS design basis P/T limit curve. However, the

conservatism of the existing Technical Specification P/T limits could not be confirmed. Therefore, the proposed revised design basis P/T limits, including allowances for pressure and temperature measurement uncertainty, must be incorporated into the Technical Specifications and supporting operating procedures.

**TSCR 376B**

**During a teleconference on Monday, February 26, 2001, Westinghouse informed the NRC that their computer code used to calculate RCS P/T limits had an error that adversely affected the Reactor Coolant System (RCS) pressure/temperature (P/T) limits used in the North Anna Units 1 and 2 RCS P/T limits Technical Specification Change Request (TSCR) (2) (10). The Westinghouse computer code OPERLIM Version 5.0 calculates RCS P/T limits by calculating combined pressure and thermal stresses in the reactor vessel during normal operation heatup and cooldown. The code was modified to incorporate changes associated with the 1996 Addenda to ASME Section XI Appendix G, including separate membrane (i.e., "pressure") stress formulations for the 1/4-thickness (1/4-T) and 3/4-thickness (3/4-T) reactor vessel locations. During heatup conditions, it is possible for the location of limiting combined stresses to change from the 3/4-T location to the 1/4-T location. Although the modifications to OPERLIM 5.0 were intended to account for this situation, the computer code modifications failed to include logic to switch the membrane stress formulation from that which applies at the 3/4-T location to that which applies at the 1/4-T location when the location of limiting stresses changes from the 3/4-T location to the 1/4-T location. The net effect of this error is a slight non-conservatism in the high temperature region of the heatup curves generated for the TSCR described above.**

**Westinghouse has provided corrected heatup P/T operating limits (14) for the North Anna Units 1 and 2 Technical Specification change request. The revised heatup curves have been modified to include allowances for temperature and pressure measurement instrument uncertainties, and to account for the pressure difference between the point of measurement (RCS hot leg) and the point of interest (reactor vessel beltline) (15). (See Appendix B of Reference (15).) The revised and modified curves are being incorporated into an NRC submittal that supplements TSCR 376 and 376A.**

**The LTOPS setpoint analysis presented to the NRC in Reference (16) is unaffected by the changes to the heatup curves, since the LTOPS setpoint analysis uses the isothermal P/T limit curve as a design limit. Similarly, the LTOPS enable temperature analysis presented in Reference [16] is unaffected by the changes to the heatup curves, since the proposed LTOPS enable temperature is a function of the design value of $RT_{NDT}$ only, which is unaffected by the changes to the heatup curves. Only the proposed Technical Specification RCS P/T limit curves applicable to heatup are affected by the changes described herein. Therefore, with the exception of the previously proposed Technical Specification heatup curves presented in Reference [16], the TSCR presented in Reference [2] and supplemented in Reference [16] remains valid.**

Revised Reactor Vessel Minimum Bolt-Up Temperature

The current design and licensing basis composite RCS pressure/temperature operator curves for North Anna Units 1 and 2 [4] [5] include a minimum reactor vessel head bolt-up temperature of 90°F. This bolt-up temperature was designed to conservatively bound the highest reactor vessel flange $RT_{NDT}$ value, including allowance for the effects of temperature measurement uncertainty. ASME Section III Paragraph G-2222(c) provides recommendations for the bolt-up temperature, indicating that the temperature of the stressed region (i.e., the vessel and closure head flanges) must be greater than the limiting $RT_{NDT}$ value of the stressed materials. As documented in UFSAR Tables 5.2-26 and 5.2-27, and in Reference (6), the highest reactor vessel flange or closure head flange $RT_{NDT}$ value for the North Anna Units 1 and 2 is –22°F (vessel flange materials).

As documented in Reference (7), Westinghouse developed a generic minimum bolt-up temperature of 60°F, based on an evaluation of available flange $RT_{NDT}$ values for Westinghouse-designed plants. Because (a) the $RT_{NDT}$ values for the North Anna Units 1 and 2 vessel flanges and closure head flanges are all well below 40°F, and (b) the RCS wide range temperature measurement uncertainty is less than 20°F (8), a revised reactor vessel

bolt-up temperature of 60°F is being implemented by the attached safety evaluation. The revised vessel bolt-up temperature will be implemented as part of the Action Plan for TSCR 376A.

## CONCLUSIONS

Changes to North Anna Units 1 and 2 Technical Specification P/T limits, and to the analysis bases for the Technical Specification LTOPS setpoints and Tenable values are proposed. These changes include:

1. Replacement of the current North Anna Units 1 and 2 Technical Specification P/T limits, including the isothermal (steady-state) P/T limit curve that constitutes the design limit for the LTOPS setpoint analysis, **with the cooldown curves** documented in Appendix F of Reference (1) **and the heatup curves documented in Appendix B of Reference (15).** The **proposed** curves have been modified to account for RCS pressure and temperature measurement uncertainty, and for the pressure difference between the point of measurement (RCS hot leg) and the point of interest (reactor vessel beltline).
2. Replacement of the current design and licensing basis RTNDT calculations, and the associated relationship of cumulative core burnup to reactor vessel neutron fluence, with those previously submitted in References (9) and (10), and
3. Modification of the analysis basis for the Technical Specification LTOPS Tenable values with a plant-specific implementation of the analysis methodology that supports ASME Section XI Code Case N-514 (12).

Implementation of these proposed revised analysis bases requires:

1. An exemption from the requirements of 10 CFR 50 Appendix G to permit application of ASME Section XI Code Case N-640 [11] to North Anna Units 1 and 2, and
2. An exemption from the requirements of 10 CFR 50 Appendix G to permit plant-specific application of the analysis methodology that supports ASME Section XI Code Case N-514 [12] to North Anna Units 1 and 2.

After consideration of the information provided herein, and in the Reference (2) submittal, the following conclusions are made:

1. The existing North Anna Units 1 and 2 Technical Specification LTOPS setpoints, enabling temperatures, and component operability requirements ensure that the RCS pressure during design basis low temperature mass and heat addition transients will not exceed the proposed revised LTOPS design basis P/T limit curve.
2. The proposed revised Technical Specification P/T limits ensure that the design basis reactor vessel flaw will not propagate under conditions of normal operation for heatup rates up to 60°F/hr, and for cooldown rates up to 100°F/hr.

These conclusions remain valid for cumulative core burnups up to 32.3 EFPY and 34.3 EFPY for North Anna Units 1 and 2, respectively.
The proposed changes to the North Anna Units 1 and 2 minimum reactor vessel head bolt-up temperatures ensures that ASME Code requirements continue to be met.

## UNREVIEWED SAFETY QUESTION DETERMINATION

There is no increased probability of occurrence or consequences of accidents previously analyzed for the proposed changes. The proposed revised analysis bases for the North Anna Units 1 and 2 Technical Specification LTOPS setpoints and LTOPS enable temperatures do not affect the operation of any system or component. No changes to any systems or components are required to implement the proposed revised LTOPS analysis bases. The revised analysis bases demonstrate that the existing North Anna Units 1 and 2 Technical Specification LTOPS setpoints, enabling temperatures, and component operability requirements are adequate to ensure that the RCS pressure during design basis low temperature mass and heat addition transients will not exceed the proposed revised LTOPS design basis P/T limit curve. The proposed revised Technical Specification P/T limits ensure that the design basis reactor vessel flaw will not propagate under

conditions of normal operation for heatup rates up to 60°F/hr, and for cooldown rates up to 100°F/hr. Therefore, the design basis requirements continue to be met, and the probability of occurrence and consequences of accidents previously evaluated are not increased.

There is no creation of the possibility for an accident of a different type than previously identified in the Safety Analysis Report as a result of these changes. The revised analysis only changes the stress intensity formulation used in the development of RCS pressure/temperature operating limits (i.e., utilizes K1c instead of K1a), and replaces the generic ASME Section XI LTOPS enable temperature formulation (i.e., RTNDT + 50°F) with a plant-specific LTOPS enable temperature analysis based on a reactor vessel fracture criterion. The proposed RCS P/T limits are not substantially different, in terms of allowable operating pressures and temperatures, than the existing P/T limits in the Technical Specifications. None of the modified analysis parameters are new or unique accident initiators. Therefore, no possibility exists for creating an accident of a different type than previously analyzed in the Safety Analysis Report.

There is no reduction in the margin of safety. ET-NAF-2000-0031 Revision 0 (3) and ET-NAF-2000-0136 Revision 1 (13) demonstrate that the proposed revised analysis methods provide an acceptable margin of safety. Because the proposed revised minimum reactor vessel head bolt-up temperatures continue to meet ASME Code requirements, the margin of safety inherent in the procedures governing reactor vessel head bolt-up is not reduced.

**99-SE-PROC-22 Rev 1**

**Description**
1-OP-10.2, Rev. 5, P1
1-OP-10.2, Rev. 8, P1
A temporary modification is to be added to procedure 1-OP-10.2 as an alternate method for loop stop valve leakage recovery. This procedure will allow the installation of a hose(s), an air pump and a check valve(s) between the suction of the PDTT pump and a LMC valve on a line going to the RP pumps.

**Summary**
A temporary modification is to be added to procedure 1-OP-10.2 as an alternate method for loop stop valve leakage recovery. This procedure will allow the installation of a hose(s), an air pump and a check valve(s) between the suction of the PDTT pump and a LMC valve on a line going to the RP pumps.

The temporary modification will be leak checked after installation. Failure of the hose would result in water from the PDTT being pumped onto the containment floor until the leak is terminated. The Loop Stop Valves will be closed during the period that this temporary modification is installed which will limit any leakage to the PDTT. Water from the RP system will be preserved by the check valve(s) that is to be installed near where this temporary modification ties into the RP system. Failure of the check valve(s) will cause a reduction in Refueling Cavity and Spent Fuel Pit level with the Spent Fuel Pit low level alarm. The failure can be quickly terminated by closing the associated LMC(s) valve. Configuration of the jumper prevents it from being able to cause a Loss of RHR condition due to air entrainment. Therefore, implemetation of this TM will not increase the probability of occurrence of an accident or malfunction of equipment previously analyzed.

Failure of the TM will not affect equipment and systems used to respond to the considered accidents. The ability to provide makeup to the RCS and cavity are not reduced by implementing this TM. Implemetation of this TM has no effect on systems or equipment required to provide backup cooling to the reactor vessel or spent fuel pit. Therefore, implementation of this TM will not increase the consequences of an accident or malfunction of equipment previously analyzed.

Configuration of the jumper prevents it from being able to create a Loss of RHR condition due to air entrainment of RHR pumps or loss of vessel level. Implementation of this jumper has no effect on equipment required for the stable maintenance of reactor vessel or spent fuel pit level and temperature. Therefore, implementation of this TM will not create the possibility of an accident or malfunction of equipment not previously analyzed.

Implementation of this jumper has no effect on the basis section of the Tech Specs. Therefore, the margin of safety as defined in the bases to the Tech Specs is not reduced.

For these reasons, an Unreviewed Safety Question does not exist.

**00-SE-TM-03 Rev 1**

**Description**

Temporary Modification TM-N1-1681

Due to corrosion, the wall thickness of the bottom head of the Service Water Air Compressor Receiver Tank was found to be less than the code allowable for the 150 psig design pressure rating of the air receiver. The maximum allowable pressure in the vessel for the minimum wall thickness found during UT was calculated in accordance with ASME Section VIII. To prevent overpressurizing the vessel, a new relief valve with a relief setpoint of 115 psig will be installed.

**Summary**

The design Service Water Air Compressor Receiver Tank relief valve has a setpoint of 150 psig which is the same as the rated design pressure of the tank as stated in UFSAR Table 9.2-4. The existing relief valve has a setpoint of 118 psi as evaluated by 00-SE-TM-03. Due to further wall thinning, a lower allowed pressure is needed until the tank can be replaced. The new relief valve setpoint will be 115 psig. This value allows for any projected additional wall thinning that may occur between now and the scheduled date of replacement for the tank. Section 9.2.1.2.4 of the UFSAR states that the SW Air Compressors operate to provide 100 psig air to the receiver tank where it is stored for use by the traveling water screen differential level control system and the SW Reservoir level indicating and alarm system. One compressor starts when the air receiver tank pressure drops to 75 psig and the other starts when the receiver pressure drops to 50 psig. The System Engineer has indicated that the lead compressor actually operates between 75 and 90 psig and the maximum pressure that the compressors provide is 100 psig. Installation of a relief valve with a setpoint of 115 psig will therefore not affect the operation of the SW Air System. The relief valve will be the same size as the former relief valve and have the same relieving capacity. The only difference in the valves will be the spring that controls the relief setpoint of the valve, therefore seismic qualification is not a concern. The relief valve relieves to the atmosphere in the SWPH.

Installation of a relief valve with a lower setpoint will protect the air receiver from possible damage due to overpressurization and will also prevent injury of station personnel. Operation of the SW Air System will be unaffected by the lower relief valve setpoint since the maximum operating pressure of the system is still approximately 15 psig less than the new setpoint. The new setpoint of 115 psig will be less than the ASME VIII code allowable pressure based on the minimum wall thickness reading obtained by UT examination.

Based on the above discussion, an unreviewed safety question does not exist for this temporary modification.