Nebraska Public Power District
Always there when you need us

50.59(d)(2)
72.48(d)(2)

NLS2018053
October 8, 2018

U.S Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555-0001

Subject: 10 CFR 50.59(d)(2) and 10 CFR 72.48(d)(2) Summary Report
Cooper Nuclear Station, Docket No. 50-298, License No. DPR-46

Dear Sir or Madam:

The purpose of this letter is for the Nebraska Public Power District to provide the summary report of evaluations that have been performed for Cooper Nuclear Station, in accordance with the requirements of 10 CFR 50.59(d)(2) and 10 CFR 72.48(d)(2). This report covers the time period from August 1, 2016, to July 31, 2018. Summaries of applicable facility changes are discussed in Attachment 1. Summaries of applicable procedure changes are discussed in Attachment 2. Summaries of applicable other changes are discussed in Attachment 3. There were no 72.48 evaluations performed during the specified time period.

There are no commitments contained in this letter.

Should you have any questions concerning this matter, please contact me at (402) 825-2788.

Sincerely,

Jim Shaw
Licensing Manager

/dv

Attachments: 1. Facility Changes
2. Procedure Changes
3. Other Changes

IE47
NRR

cc: Regional Administrator w/ attachments
USNRC - Region IV

Senior Resident Inspector w/ attachments
USNRC - CNS

Cooper Project Manager w/ attachments
USNRC - NRR Plant Licensing Branch IV

NPG Distribution w/o attachments

CNS Records w/ attachments

Attachment 1

Facility Changes

The following list provides a summary of 50.59 evaluations that were prepared to support facility changes that were implemented at Cooper Nuclear Station (CNS) during the time period from August 1, 2016 to July 31, 2018.

Change Evaluation Document (CED) 6036444
(Evaluation 2013-3, Revision 2)

Title: Remove Heater Bay Steam Leak Detection Temperature Switches from Group 1 Isolation Logic

Description: The proposed plant modification CED will disconnect all four Trip Systems of the Heater Bay Steam Leak Detection temperature switches (MS-TS-143A thru MS-TS-150D). The result is the Heater Bay Steam Leak Detection switches will no longer be part of the Primary Containment Isolation System (PCIS) Group 1 Isolation logic.

These 32 temperature switches located in the Heater Bay are part of Trip Channel A1, A2, B1, and B2 for the Group 1 Isolation. After this CED is installed, these switches will not input to the PCIS Group 1 Isolation logic.

Technical Specifications Bases B3.3.6.1 discusses the Main Steam Tunnel Temperature-High Function with respect to the 16 temperature switches located in the Main Steam Tunnel. This CED removes temperature switches in the Heater Bay only and does not affect the Main Steam Tunnel temperature switches. The Technical Specifications Bases B3.3.6.1 states the following:

> *Any one switch tripping in its trip system plus any one switch tripping in the other trip system will result in isolation of the MSIVs [Main Steam Isolation Valves] and MSL [Main Steam Line] drains. For purposes of this specification, each temperature switch is considered a "channel".*

The Main Steam Tunnel temperature switch logic is a 1-out-of-8 taken twice logic. Any one temperature switch in Trip Channel A concurrent with any one temperature switch in Trip Channel B will cause a Group 1 Isolation. The logic associated with the temperature switches located in the Heater Bay is similar; however, there are more temperature switches in each Trip Channel. The Heater Bay temperature switch logic is a 1-out-of-16 taken twice logic. Any one temperature switch in Trip Channel A concurrent with any temperature switch in Trip Channel B will cause a Group 1 Isolation.

The Technical Requirements Manual (TRM) T3.3.4 requirement (which applies to the Main Steam Line Leak Detection temperature switches in the Heater Bay) states that two channels are operable for each trip system. There are two Trip Systems (A and B) that are associated with the Main Steam Line Leak Detection temperature switches. Each Trip System is comprised of two Trip Channels (i.e., A1 or A2 for Trip System A and B1 or B2 for Trip System B) of which only one of the two Trip Channels are required to maintain the Trip System. Additionally, each Trip Channel (A1, A2, B1, or B2) is comprised of eight temperature switches (channels) associated with the Heater Bay leak detection. The TRM is being revised to delete T3.3.4 and thus the requirement for two operable channels of Heater Bay Steam Leak Detection switches.

Final Safety Analysis Report (FSAR) Amendment 25, Supplement 1, to the Safety Evaluation Report for CNS and Updated Safety Analysis Report (USAR) Section IV-12 provide the High Energy Line Break (HELB) Analysis, which includes the Main Steam Line Break, but do not credit the temperature switches for any mitigating function in a design basis Main Steam Line Break.

Implementation of the change requires various surveillance, operating and maintenance procedure changes which are consistent with the change. This evaluation also provides the regulatory basis for these associated changes to plant procedures.

10 CFR 59
Evaluation: The proposed activity may be implemented without prior Nuclear Regulatory Commission (NRC) approval and without obtaining a License Amendment.

The PCIS of which the Group 1 Isolation is a part is not considered as an initiator for any accident evaluated in the USAR.

Removing the Heater Bay temperature switches will not increase the likelihood of occurrence of a malfunction of any other portion of the Group 1 Isolation function.

There is no environmentally qualified or safety related equipment located in the Heater Bay. The equipment to mitigate and bound a break in the Main Steam Lines (including the Main Steam Line High Flow instrumentation, MSIVs, etc.) is located in the Reactor Building and the temperature switches and associated logic for this area are unaffected by this CED. Therefore, any localized environmental conditions in the Turbine Building will not impact the ability to meet the safety evaluation in the USAR.

Given that (1) the USAR, in Section VII-3.3.8.5, states that the maximum Design Basis Accident (DBA) dose is mitigated by the Main Steam Line High Flow instrumentation (does not credit the Main Steam Line Space temperature switches):

> *3.3.8.5 Main Steam Line Space High Temperature*
>
> *High temperature in the space in which the main steam lines are located outside of the primary containment (USAR Table V-2.2, isolation signal D) could indicate a breach in a main steam line. The automatic closure of various Class A valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the reactor coolant pressure boundary. However, per USAR Section XIV-6.5, the maximum DBA dose is mitigated by the Main Steam Line High Flow instrumentation.*

and (2) that USAR Chapter XIV, Section 6.5.8, states "the bases for the Table XIV-6-20 dose calculation was that for a break less than that required for automatic closure, operator action would occur to terminate the break five minutes after its initiation.... Even if one assumes that 30 minutes is required to determine there is a break and isolate the reactor, the resultant dose is two orders of magnitude less than that for the DBA." It can be concluded that for large breaks, the MSL temperature switches are not credited and for small breaks, the system would be used for identification of a leak and operator action would occur to terminate the break.

USAR Section IV-12 and FSAR Amendment 25 address the HELB, which takes credit only for the high flow isolation signal for large breaks, and does not require evaluation of the critical crack in the Turbine Building since the only affected structures, systems, and components (SSC) are required only for power production and not safe shutdown of the reactor. No action by these temperature switches is required by any scenario included in the HELB analysis.

A small leak of 1% to 10% full power steam flow, which this leak detection system is designed to detect, does not threaten the integrity of the fuel barrier because a leak of this magnitude does not challenge the makeup capability of the Feedwater system. The dose consequence of a small break in this size range is minimal, two orders of magnitude less than the DBA MSL Break.

Based upon the above discussion, removing the Heater Bay Steam Leak Detection temperature switches will not result in more than minimal increase in the consequences of an accident previously evaluated in the USAR.

The consequences of a malfunction of the PCIS Group 1 Isolation is unaffected by removing the Heater Bay temperature switches.

There is no scenario in which a malfunction of the PCIS system, including any malfunction that could result from removing the Heater Bay temperature switches would create an accident of a different type than previously evaluated in the USAR.

This activity has no effect on any of the fission product barriers of fuel cladding, reactor coolant pressure boundary, or containment.

No input or methodology which is used in establishing the design basis or used in the safety analysis is changed with the implementation of the CED.

Change Evaluation Document 6033800
(Evaluation 2015-2, Revision 0)

Title: Station Startup Service Transformer (SSST) Replacement

Description: The CED replaces the original (161 kV/4160 V/4160 V) 30 megavolt ampere (MVA) SSST with a new 36 MVA transformer. The new transformer has the ratings and capacities to compensate for grid voltage events and accommodate all loading conditions. The 161 kilovolt (kV) and 4160 volt (V) connections will be reworked to fit up to the new transformer. New controls and monitoring components, including manually controlled On-Load Tap Changers (LTC) for the two 4160 V windings, on-line dissolved gas monitoring, and enhanced electronic temperature monitoring, are included in this design.

Other new instrumentation and control devices being added include control room panel modifications for controls for the LTCs and associated meters, new annunciator alarms and signals to relate tap position indication to Nebraska Public Power District's Doniphan Control Center. The LTCs associated with each secondary side winding will allow adjustment of 4160 voltage with the transformer energized and loaded. LTC position will be controlled by procedure based grid voltages. LTC position changes are not assumed (i.e., not necessary) in response to USAR defined Abnormal Operational Transients or DBAs. LTC position changes may be necessary to account for grid voltage changes to assure that the LTC remains in the appropriate procedurally defined pre-accident position to perform its required function.

Overvoltage relays are included in the 1A and 1D switchgear to monitor the low-voltage windings to protect against an LTC failure mode and operator errors. These relays will interrupt the raise operation for the LTC and provide control room alarming. Site procedures will be revised to provide the required guidance for monitoring and control of the new transformer.

Construction activities will also be performed with the potential to inadvertently actuate the existing SSST Sudden Gas Pressure (SGP) relay, which would electrically isolate/de-energize the SSST. To prevent this, the SGP lockout relay will be temporarily disabled by this CED.

The Fire Protection (FP) System for the SSST is also being upgraded. The existing deluge and detection system for FP System 19 are replaced, including the deluge valve. Two new fire walls are provided for fire/explosion protection. One fire wall is between the SSST and the Emergency Station Service Transformer (ESST) and the second fire wall is on the north side of the SSST.

10 CFR 50.59
Evaluation: Based on this evaluation the CED may be installed as designed without NRC prior approval.

The SSST is one of two qualified offsite power sources, with the ESST the other. The loss of both of these offsite power sources (LOOP) is assumed coincident with applicable DBAs, including a Loss of Coolant Accident (LOCA) and some Abnormal Operational Transients. Since a LOOP is assumed coincident with these accidents, a LOOP is not an initiator for these events.

Station Blackout (SBO) Consideration

An SBO is a special event that is evaluated in the USAR. If the failure rate of the new SSST is sufficiently high, there could be an increase in the frequency of an SBO. The failure rate of the SSST is composed of two parts: the reliability of the transformer itself; and the availability of the transformer to perform its design function, considering changes in grid voltage. With the addition of the LTC, the SSST has increased its ability to perform its design function of supplying the correct voltage to the critical 4160 V switchgear since it can now adjust to changing grid or plant conditions. With this increased availability, the SSST can perform its design function during greater grid extremes, increasing the reliability of this offsite source.

Grid voltages have challenged the ability of the existing SSST to perform its function as often as several times a year. Conversely, the addition of an LTC does decrease the reliability an amount. Discussions with the transformer and LTC manufacturers indicate that the LTC utilized on the new SSST is very reliable, with no expected failures of the life of this new transformer.

Qualitatively, it is reasonable to conclude that the decrease in reliability will not cause failures on the order of several times a year, or for that matter, even once per year. As a result, it is concluded that overall, occurrences that the new SSST cannot perform its design function are reduced. Similarly, due to the increased availability of the new transformer, the frequency of an SBO is similarly reduced, and not increased.

Reactivity Change Consideration

When the SSST is supplying power to the Reactor Recirculation Pump(s) and assuming that the LTC should fail and cause an uncontrolled increase in voltage, the increase in voltage will cause a positive reactivity excursion as the Recirculation Pump Motor-Generator sets speed up. A worst case scenario of full LTC travel starting at the lowest setting and other conservative assumptions has been shown to result in a 0.310% speed increase in the Reactor Recirculation Pumps. Using that speed change, the predicted maximum reactor thermal power increase, over the life cycle of the core is 6.1 megawatt thermal (MWth) near the end of core life. 6.1 MWth is approximately 0.26% of 2381 MWth and 0.25% of 2419 MWth, and favorably compares to the Appendix K 2% value.

In addition, this slight change in core thermal power is bounded by the following existing Abnormal Operational Transients in the USAR.

- USAR XIV Section 5.6.1: Recirculation Flow Control Failure - Increasing Flow
- USAR XIV Section 5.6.2: Startup of Idle Recirculation Pump

These two Abnormal Operational Transients are provided as a basis of comparison. Section 5.6.1 assumes a control system failure, and assumes a pump run up of a minimum of approximately 40%. An SSST LTC failure cannot initiate a control system failure. Section 5.6.2 is a startup of an idle pump from zero to approximately 20% flow. An SSST LTC failure cannot cause an idle pump to start.

The failure rate of the SSST is composed of two parts: the reliability of the transformer itself; and the availability of the transformer to perform its design function, considering changes in grid voltage. With the addition of the LTCs, the SSST has increased its ability to perform its design function of supplying the correct voltage to the critical 4160 V switchgear since it can now adjust to changing grid or plant conditions. With this increased availability, the SSST can perform its design function during greater grid extremes, increasing the reliability of this offsite source.

Grid voltages have challenged the ability of the existing SSST to perform its function as often as several times a year. Conversely, the addition of a LTC does decrease the reliability an amount. Discussions with the transformer and LTC manufacturers indicate that the LTC utilized on the new SSST is very reliable, with no expected failures over the life of this new transformer.

In addition, and although the new transformer and its control system is not required to be single failure proof, the following aspects of the design were considered, specific to the LTC overvoltage controls:

- If the new overvoltage relay that monitors bus voltage fails (i.e., fails such that is will not respond to an actual bus overvoltage condition), a second failure (within the LTC), or an operator error is necessary to result in unacceptably high bus voltages.

- If the new overvoltage relay that monitors bus voltage fails (i.e., actuates when bus voltage is acceptable), no changes to the SSST's output voltage will occur. A second failure (within the LTC) is necessary to result in unacceptably high bus voltages.

- If the new normally energized LTC raise blocking relay (that works in conjunction with the new overvoltage relay) were to fail, the LTC would not change position. The LTC would be prevented from changing position in the raise direction. Since procedural controls assure that the LTC be in the required pre-accident position, an unexpected relay failure has no immediate impact to SSST function. The failed condition of the LTC raise blocking relay is alarmed and subsequent operation and functional capability would be addressed via the corrective action program.

Qualitatively, it is reasonable to conclude that the decrease in reliability will not cause failures on the order of several times a year, or for that matter, even once per year. As a result, it is concluded the frequency of occurrences that the new SSST cannot perform its design function are reduced.

Therefore, based on the discussion above, the overall ability of the SSST to supply offsite power within the required voltage range has been improved. This change does not result in more than a minimal increase in the likelihood of occurrence of a malfunction of an SSC important to safety previously evaluated in the USAR.

All pre-existing USAR-described dose analyses have been reviewed. Specifically, all analyses will remain both valid and bounding following implementation of this modification. Therefore, the loss of one of the qualified offsite power sources, the SSST, by failure of the LTC will not change the consequences of an SBO, LOOP, LOOP/LOCA, Abnormal Operational Transient, or any other accident accompanied by a LOOP.

The addition of the LTCs to the SSST introduces an operator maloperation vulnerability that could cause transformer output voltages to change from desired values. In addition, the LTC could fail and change SSST output voltage absent operator action.

If an LTC fails or is operated in the low direction, it could result in voltage conditions comparable or identical to that of degraded grid conditions. For the F and G buses, if the voltage is sufficiently low, a pre-existing undervoltage trip of the 4160 V buses could occur with a subsequent start and loading of the Emergency Diesel Generators. Annunciator C-1/A-7 provides control room indication of the low/undervoltage condition for these two buses.

If an LTC fails or is operated in the high direction, an overvoltage relay included in the design will stop the raise function when voltages exceed the trip setpoint. New Annunciator C-2/C-9 will provide the control room with an indication of the overvoltage condition. The trip setpoint has been selected to assure that the connected buses will not be subjected to undesirably high voltages.

Following the overvoltage relay action, and if the LTC responds to operator command, the LTC will be adjusted down per procedural direction. The new action to respond to an overvoltage alarm is acceptable since the action is proceduralized and included in operator training. Tap changes can be made in a timely manner since the controls are located in the control room. Tap position and bus voltage indication are located on the control panels near their associated LTC controls. These controls/indications and the alarm provide immediate feedback in the event that the operator taps in the wrong direction. As such, the new alarm response action is acceptable.

If the LTC will not respond to operator command, action will be necessary to disconnect the buses from the SSST or validate that the LTC has stopped in a normal position (i.e., is not mid-position between tap settings), again per procedural direction. If applicable, the need to disconnect the SSST from the buses is due to a limitation of the transformer itself. If the LTC stops movement in response to the overvoltage relay, the LTC could be stopped in a physical position that does not support long term full load operation (mid-position). The transformer manufacturer and the LTC manufacturer provided information that at an assumed full load, the transformer can continue to operate for a minimum of 30 minutes in an LTC midposition. The new alarm response action to respond to an overvoltage alarm is acceptable since the action is proceduralized and included in operator training. Bus disconnection from the SSST can be made in a timely manner since the required controls are located in the control room. As such, the new alarm response action is acceptable.

In either case, 30 minutes is sufficient time for an operator to respond to the overvoltage alarm and implement an appropriate response. The worst case consequence of the described failures is equal to the loss of this particular offsite source (e.g., due to 161 kV feed/power supply problems, etc.).

In addition, all pre-existing USAR-described dose analyses have been reviewed. Specifically, all analyses will remain both valid and bounding following implementation of this modification. Therefore, there are no malfunctions evaluated in the USAR that have their radiological consequences affected as a result of the SSST replacement.

The loss of both offsite power sources is a component of SBO, a special event that is evaluated in the USAR, and a LOOP is also assumed during accident scenarios in the USAR. The Abnormal Operational Transient of reactor core coolant flow increase resulting in increased reactor power is evaluated in the USAR.
The addition of the manually operated LTCs and overvoltage relays can now result in unintended bus voltage variations or the failure to be able to adjust voltage. These conditions only create new failure modes. The failure effects or results of those failures, the loss of the SSST to perform its design function or an increase in reactor core coolant flow, are already evaluated or bounded by existing evaluations in the USAR. Therefore, the result of any failure of the SSST is not an accident of a different type.

While the cause or mode of the malfunction of the new SSST may be different with the addition of LTCs and overvoltage relays, the malfunctions are not a new result. The worst case result of any malfunction is still the loss of the SSST, which is bounded by existing LOOP assumptions in the USAR, or an LTC failure resulting in increased reactor core coolant flow, which is bounded by other Abnormal Operational Transients already evaluated in the USAR.

This modification of the SSST, and the associated changes, has no involvement, either directly or indirectly, with any of the Design Basis Limits associated with:

- Fuel cladding
- Reactor Coolant System
- Containment

Therefore, this modification, and subsequent utilization of the equipment, does not and cannot exceed or alter any of these fundamental limits.

The SSST modification is comprised entirely of physical changes supported by existing methods of evaluations or by methods of evaluations not described in the USAR that do not satisfy the definition of Methods of Evaluation provided in definition 3.10 of Nuclear Energy Institute (NEI) 96-07, Revision1. Therefore, the replacement SSST project does not involve any different methods of evaluations than described in the USAR.

Engineering Change 6038060
(Evaluation 2018-01, Revision 0)

Title: Open Phase Protection (OPP) System

Description: Installation of two PSStech Open Phase Protection devices on the high side of the 161 kV - 4160 V SSST with the capability to energize a lockout relay and isolate the source from the 4160 V buses.

Installation of two PSStech Open Phase Protection devices on the high side of the 69 kV - 4160 V ESST with the capability to energize a lockout relay and isolate the source from the 4160 V buses.

In both applications, the PSStech devices will be installed in a 2-out-of-2 logic for each transformer to actuate a trip. If one device is non-functional, the trip logic will fail to the alarm-only state. Each device (channel) will initiate a control room annunciator if it becomes non-functional.

These proposed changes are adverse because they add an input to an existing trip function (sudden gas pressure) whose spurious operation could isolate plant electrical buses from a qualified offsite source, which can cause a plant trip and/or start an onsite alternating current (AC) source depending on plant configuration at the time.

The following design functions are affected by the proposed activity:

1. The startup AC power source shall provide a source of off-site AC power to the critical service portion of the auxiliary power distribution system adequate for the safe shutdown of the reactor. The startup AC power source shall be capable of supplying all loads on the critical service portions of the auxiliary power distribution system. The emergency core cooling system loads are sequenced on to the critical bus under LOCA conditions. The availability of the startup AC power source shall be monitored by indication provided in the main control room. The startup AC power source shall be automatically connected to the auxiliary power distribution system including the critical service portion in the event that the normal AC power source is lost. The startup AC power sources shall be as independent as possible from the emergency and normal AC sources within the constraints of the transmission system development. The startup AC power source shall not be synchronized with the emergency AC power source except to permit live source transfers. The startup AC power source shall not be synchronized with the standby power source except to permit live source transfers and for standby power system performance tests.

2. (Emergency AC Power Source) To provide an additional source of power to the critical service portion of the auxiliary power distribution system to back up the normal and startup sources and to permit portions of the 345 kV system to be removed from service for inspection, testing, and maintenance. The emergency AC power source shall be capable of providing electric power to all equipment which is required for the safe shutdown of the reactor. The emergency AC power source shall be as independent as possible from the startup AC power source within the constraints of the transmission system.

10 CFR 50.59
Evaluation: NRC prior approval is not required for this change.

The PSStech OPP protection affects the 161 kV SSST and 69 kV ESST offsite power circuits by tripping the circuit breakers between the transformer and the plant buses if they are not supplied with 3-phase power as designed by the manufacturer for steady state operation. The plant response to postulated accidents is not affected.

The design and testing of the PSStech OPP devices are sufficient to produce a reliable design such that there is not a more than minimal increase in the frequency of occurrence of an accident previously evaluated in the USAR or in the likelihood of a malfunction of an SSC important to safety (offsite power source). The OPP devices are normally configured in a 2-out-of-2 coincidence logic to protect against inadvertent trips. No failures can cause the firmware portion of the devices to cause a trip of both offsite power circuits. The settings are different for the ESST and SSST, so an error in setting is unlikely to affect both offsite power supplies.

As stated in NEI 96-07, Section 4.3.5, a new initiator of an accident previously evaluated in the USAR is not a different type of accident, and (from NEI 96-07, Section 4.3.6) a new failure mechanism is not a malfunction with a different result if the result or effect is the same as, or is bounded by, that previously evaluated in the USAR.

Therefore, the evaluation concludes that there is no more than a minimal increase in the consequences of an accident or consequences of a malfunction; no possibility of an accident of a different type or for a malfunction with a different result; and no Design Basis Limit for a Fission Product Barrier is exceeded or altered. There is no change to any evaluation methodologies described in the USAR.

Attachment 2

Procedure Changes

The following list provides a summary of 50.59 evaluations that were prepared to support procedure changes that were implemented at Cooper Nuclear Station (CNS) during the time period from August 1, 2016, to July 31, 2018.

Procedure 2.0.1.3, Revision 3 / Updated Safety Analysis Report (USAR) Change Request (UCR) 2015-028
(Evaluation 2015-04, Revision 1)

Title: Time Critical Operator Action for Suppression Pool Cooling (SPC)

Description: The generic Boiling Water Reactor-4 initiation time for the Residual Heat Removal (RHR) system in the SPC mode used in the station's Anticipated Transient Without Scram (ATWS) analysis has proven to be unrealistic with only one minute for operators to manually align the RHR system after ten minutes of no operator action. After investigation into the sensitivity of Primary Containment temperature to this initiation timing, the initiation time demonstrated by procedure is being relaxed. CNS Procedure 2.0.1.3, "Time Critical Operator Action Control and Maintenance," will be updated to reflect a more realistic time of 30 minutes for operator manual action to line up the RHR system in the SPC mode following an ATWS. USAR Chapter XIV, Section 5.9.3, "Anticipated Transient Without Scram," will be updated to reflect the time of 43.5 minutes (208°F Peak Suppression Pool Temperature) determined by Engineering Report 15-003. Thirty minutes is chosen for two reasons; 1) to provide margin to the 43.5 minute time and ensure a peak suppression pool temperature less than 208°F, and 2) establish a time for Procedure 2.0.1.3 that is readily achievable. The two activities are as follows:

1. Procedure Change Request to CNS Procedure 2.0.1.3, "Time Critical Operator Action Control and Maintenance"

2. UCR to USAR Chapter XIV, Section 5.9.3

10 CFR 50.59
Evaluation: This activity can be implemented without prior Nuclear Regulatory Commission approval.

Key design features credited in the ATWS analysis are Standby Liquid Control, Alternate Rod Insertion and Recirculation Pump Trip. While the initiation timing of the RHR system is a credited manual action in the station's ATWS analysis, the impact to Primary Containment temperature and pressure response remains well within the design limits of Primary Containment. This margin is the station's and the change to margin does not represent a significant reduction. The new initiation timing of the RHR system in the SPC mode in conjunction with these key design features which are unaffected assure that fuel integrity, reactor integrity, and Primary Containment integrity are assured under ATWS conditions.

The applicable requirements established by Nuclear Energy Institute 96-07, Revision 1, Section 4.3.2, Example 4, have been answered and show that the change to the manual action proposed by this evaluation will not result in a more than minimal increase in likelihood of any of the criteria set forth by the 10 CFR 50.59 process.

The frequency of occurrence and the consequences of accidents evaluated in the USAR are not changing due to the proposed activity.

The proposed activity does not introduce the possibility of a different type of accident, or create the possibility for a malfunction of a structure, system, or component important to safety with a different result than previously evaluated in the USAR.

This activity does not result in the design limits of a fission product barrier being exceeded or changed.

Procedure 6.SUMP.101
(Evaluation 2017-01, Revision 0)

Title: Troubleshooting Z1 Sump Pump

Description: Troubleshooting will be performed to investigate the cause of Z1 Sump pump failure to start during performance of Procedure 6.SUMP.101. A marked up copy of Procedure 6.SUMP.101 will be used and the functional Z2 Sump pump will be de-energized by opening its local power supply disconnect. Existing steps in the procedure to maintain Z2 pump available will be used to ensure Standby Gas Treatment (SGT) operability during troubleshooting. This is a compensatory action to maintain SGT operable. The work is being performed under Notification 11330203 and Procedure 6.SUMP.101.

10 CFR 50.59
Evaluation: The proposed action requires a qualified operator in continuous communication with the control room stationed in the Off Gas Building to restore power to Z2 Sump pump to maintain operability of SGT. The compensatory measure is a manual action to restore the automatic function to keep Z Sump levels below the SGT exhaust line. Once the local power supply disconnect is closed, the automatic function is restored and no further operator action is required.

The applicable design basis event is the loss of coolant accident with concurrent loss of offsite power (LOOP) with the worst case single failure. The worst case single failure results in the loss of a single diesel generator (DG). The LOOP will cause the plant to enter Procedure 5.3EMPWR which contains actions to provide temporary power to either Z Sump pump if required. Power is supplied via a long electrical power cable from the available DG to the available Z sump pump. The procedure uses a separate power connection in the Off Gas Building and a separate disconnect to supply power.

The function of the SGT system is to ensure that radioactive materials that leak from the Primary Containment into the Secondary Containment following a Design Basis Accident (DBA) and secondary containment isolation are filtered and adsorbed prior to exhausting to the environment. The SGT system consists of two fully redundant subsystems, each with its own set of ductwork, dampers, charcoal filter train, and controls. Both SGT subsystems share a common inlet plenum. This inlet plenum is connected to the reactor building exhaust plenum, the Primary Containment, and the High Pressure Coolant Injection turbine gland seal exhauster. Both SGT subsystems exhaust to the Elevated Release Point tower through a common exhaust duct served by two 100% capacity system fans. Both fans automatically start on a Secondary Containment isolation signal. As this air flows through various piping, the moisture contained within the air condenses. This condensed water is drained to Z Sump.

The Z Sump has the active safety function of pumping out the collected water, which would otherwise eventually fill the sump and back up into the SGT exhaust line, impeding the flow of air. The Z Sump pumps and level controls are essential and are powered from the critical buses.

For the troubleshooting being performed per Notification 11330203 and Procedure 6.SUMP.101, an operator is stationed in the Off Gas Building to restore power with the local disconnect and will be in communication with the control room. The licensed operators in the control room have immediate access to information indicating initiation of SGT and will communicate the need for Z Sump pumps to the operator in the Off Gas Building. Therefore the time to restore power to Z2 Sump pump and its automatic function is a very short time, typically less than five minutes.

These times are much less than the time required to route temporary power per Procedure 5.3EMPWR, Attachment 5, which takes about one hour. NEDC 95-001 calculated that it takes hours for condensation to reach the SGT line. This was determined under the most limiting conditions that could exist in Secondary Containment after the design basis event. Therefore, restoring the automatic function within a short time period (typically less than five minutes) is not an adverse change.

This compensatory action may be implemented.

Attachment 3

Other Changes

The following list provides a summary of 50.59 evaluations that were prepared to support other changes that were implemented at Cooper Nuclear Station during the time period from August 1, 2016, to July 31, 2018.

Engineering Change (EC) 18-012
(Evaluation 2018-2, Revision 0)

Title: Extending Inspection Duration of Underwater Torus Region

Description: EC 18-012 provides the technical basis for extending the American Society of Mechanical Engineers (ASME) Section XI VT-1 visual examination/desludging/pitting recoating repair frequency on 100% of the wetted portion of the Torus from one refueling cycle (approximately two years) to two refueling cycles (approximately four years) and remain within the ASME Code required inspection frequency. Conclusions of this evaluation determined it is acceptable to extend the visual/desludging/recoating repair activities to two refueling cycles conditional on performing volumetric examinations of select test evaluation locations every outage in order to monitor/trend corrosion degradation. This EC provides the technical basis for revision of the Updated Safety Analysis Report (USAR) and Nuclear Regulatory Commission commitments NLS2010050-2 and -03 accordingly.

10 CFR 50.59
Evaluation: Extending the duration between visual inspection/desludging and recoating repair of pits from two years to four years does not result in any precursors to any accidents described in the USAR, or of a different type not described in the USAR. The change will not reduce the effectiveness of the Containment Inservice Inspection Program, and thus will neither increase the likelihood of a malfunction of equipment important to safety, nor create the possibility of a structure, system or component malfunction with a different result. There is no impact on the radiological consequences of accidents or malfunctions previously evaluated in the USAR. This change does not cause the Containment pressure boundary design function to be reduced or altered, and is not associated with any methodology described in the USAR.