ATTACHMENT 5

Point Beach Units 1 and 2
License Amendment Request to Revise Technical Specifications
to Adopt Risk Informed Completion Times TSTF-505, Revision 2,
“Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b”

Evaluation of Plant-Specific Variations

Evaluation of Plant-Specific Variations

The following provides an evaluation of the plant-specific variations from TSTF-505, Revision 2, identified in Section 2.4.2 of this amendment request. Attachment 4 of this amendment request provides a cross-reference of the proposed Point Beach TS changes in comparison to TSTF-505, Revision 2, including the plant-specific variations evaluated below. Attachment 4 is provided for information only and is not intended to represent a comprehensive assessment of the proposed plant-specific variations.

1) TS 3.3.1, Table 3.3-1, RPS Instrumentation Variations

   i. Power Range Neutron Flux - High (FU 2a)

   The Power Range Neutron Flux-High trip protects against reactivity excursions from a subcritical or low power operation condition to prevent departure from nucleate boiling (DNB) and protects against reactivity excursions during power operation to prevent DNB. The four channels of power range detectors are spaced around the core at approximate 90-degree intervals to account for radial dependencies in neutron flux and the circuity averages the signals from the dual section (top and bottom) detectors to account for axial dependencies. The power range neutron flux detectors monitor from 0% to 120% reactor power and provide signals for permissives that automatically bypass or restore certain primary reactor trips during startup, shutdown, and low power operation.

   The reactor trip coincidence logic for the Power Range Neutron Flux-High trip is two-out-of-four channels. The four-power range neutron flux channels provide a protection function for overpower protection but isolated outputs from all four channels are averaged to also provide a control function for automatic control rod regulation of power. Should one of the channels fail in such a way as to produce a low power output, the channel is incapable of overpower protection and could also impact automatic control rod regulation, potentially causing an initiating event. As a result, the single failure criterion of IEEE-279 (Reference 1), requires that a second overpower protection channel is assumed to fail, leaving the remaining two-out-of-four overpower trip channels available to assure an overpower trip if needed. With an inoperable channel manually placed in the trip position, the Power Range Neutron Flux-High trip converts to a one-out-of-three channel coincidence logic.

   As indicated in Table E1-1 of Enclosure 1, the Power Range Neutron Flux-High trip is evaluated in the PRA by means of a surrogate which fails the reactor trip breaker (RTB) associated with the channel's trip logic to conservatively bound the risk increase associated with this function.

   Point Beach TS 3.3.1, Table 3.3-1, Condition D, requires the power range neutron flux channel to be placed in the tripped position within one hour of inoperability. Point Beach Condition D differs from the STS of NUREG 1431 (Reference 2), and thereby TSTF-505, Revision 2, in not additionally requiring either a thermal power reduction to less than 75% Rated Thermal Power (RTP) within 78 hours or verification every 12 hours of the quadrant power tile ratio (QPTR) within limit using the movable incore detectors. As described above, sufficient redundancy exists in the Power Range Neutron Flux-High trip circuitry to assure at least two channels are available to implement the trip function if needed during the extended period allowed by the RICT given the single failure criterion of IEEE-279. The plant-specific variation is acceptable since the trip function is adequately evaluated by means of a surrogate in the PRA and the absence of requirements to additionally reduce thermal power or conduct QPTR surveillances does not affect the Power Range Neutron Flux-High trip capability during the proposed RICT. Thereby Condition D is appropriate for inclusion in the Point Beach RICT Program.

   ii. Reactor Coolant Flow - Low, Single Loop (FU9a)
   Reactor Coolant Flow - Low, Two Loops (FU9b)

   The Reactor Coolant System (RCS) low-flow trip functions provide protection from violating the DNBR limit due to low flow in one or more RCS loops, while avoiding reactor trips due to normal variations in RCS loop flow. Each of the two RCS loops have three flow detectors to monitor RCS flow. The flow

signals are not used for any control system input. In MODE 1 above the P-8 permissive setpoint, approximately 35% RTP, a loss of flow in one RCS loop could result in DNB conditions in the core because of the higher power level. In MODE 1 below the P-8 permissive and above the P-7 permissive, approximately 10% RTP, a loss of flow in two or more loops is required to actuate a reactor trip because of the lower power level and the greater margin to the DNB design limit. Below the P-7 permissive, all reactor trips on low flow are automatically blocked since there is insufficient heat production to generate DNB conditions. The RCS Flow - Low single loop and two loop trips are primary reactor trips.

The reactor trip coincidence logic for the RCS Flow - Low (Single Loop) trip when above the P-8 permissive and the RCS Flow-Low (Two Loops) trip when between the P-7 and P-8 permissives are both two-out-of-three channels. The RCS Flow-Low setpoints specified by the Point Beach TS is 178,000 gpm, which equates to 90% of the total nominal flow which and is 3% above the low RCS loop flow setpoint assumed in the safety analyses to account for uncertainties. Placing an RCS Flow-Low channel in the tripped condition when above the P-8 permissive results in a partial trip condition requiring only one additional channel in the same RCS loop to initiate a reactor trip. Likewise, one RCS Flow-Low channel in the tripped condition on both RCS loops results in a partial trip condition requiring one additional channel in both RCS loops to initiate a reactor trip when between P-7 and P-8.

As indicated in Table E1-1 of Enclosure 1, the Reactor Coolant Flow - Low, single and two loop trips are evaluated in the PRA by means of a surrogate which fails the RTBs associated with the channels' trip logic to conservatively bound the risk increase associated with this function.

Point Beach TS 3.3.1, Table 3.3-1, specifies functional units, FU9a and FU9b, for the RCS Flow-Low (Single Loop) and RCS Flow-Low (Two Loops) trip instrumentation, respectively. Point Beach TS 3.3.1, Table 3.3-1, differs from STS TS 3.3.1, Table 3.3-1, and thereby TSTF-505, Revision 2, which specify a single functional unit, FU10, for the RCS Flow-Low trip instrumentation without distinction of one versus two affected RCS loops. The variation in Point Beach's two versus the STS's single functional unit for the RCS Flow - Low reactor trip function is similar to the administrative variation described in Section 2.4.1.1 of this amendment request in that the Point Beach TS are based on NUREG-1431, Revision 1 (Reference 3), and subsequent changes to the RCS Flow - Low reactor trip requirements in NUREG-1431 were not all incorporated into the Point Beach TS.

Point Beach TS 3.3.1, Table 3.3-1, Condition L, requires the RCS Flow-Low (Single Loop) channel to be placed in the tripped position within one hour of inoperability. Point Beach Condition L differs from the STS of NUREG 1431 (Reference 2), and thereby TSTF-505, Revision 2, in requiring a power reduction below the P-8 permissive, in lieu of a power reduction below the P-7 permissive, if the Completion Time is not met. The Point Beach P-8 permissive setpoint is ~35% RTP whereas the P-7 permissive setpoint referenced in the STS is 10% RTP, according to the STS Bases for NUREG-1431. Lowering reactor power to below 10% RTP for a single inoperable RCS Flow-Low trip channel that cannot be restored within the Completion Time is not commensurate with the impact of the inoperability on safety given that the RCS Flow-Low (Single Loop) trip is blocked below ~35% RTP. Reducing power to below 35% RTP would exit the MODE of Applicability for the RCS Flow-Low (Single Loop) reactor trip, according to footnote (f) for FU9a of Point Beach TS 3.3.1, Table 3.3-1. Sufficient redundancy exists in the RCS Flow-Low circuitry to assure at least two channels are available above P-8 to implement the RCS Flow-Low (Single Loop) trip function if needed during the extended period allowed by the RICT. The plant specific variations regarding the Point Beach functional unit description for the RCS Flow - Low reactor trips and the default Conditions for the RCS Flow-Low (Single Loop) reactor trip above the P-8 permissive are acceptable since the Rx trip functions are adequately evaluated by means of a surrogate in the PRA and placing the inoperable channel in the tripped position results in a partial-trip condition requiring only an additional, RCS loop channel to initiate a reactor trip. Thereby, Condition L is appropriate for inclusion in the Point Beach RICT Program.

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iii. Reactor Trip Breakers (RTBs), (FU 18, MODES 1,2)

The RTB trip function consists of two redundant trains of RPS trip logic and associated trip breakers installed downstream of the protection channel trip bistables and aligned in series to assure that control rod drive power is interrupted on a valid trip, even if a single failure prevents one RPS train from tripping or causes one breaker to stick closed. When coincidence logic is satisfied, the trip relays interrupt power to the associated reactor trip breaker UV coil, opening the breaker and dropping the control rods. Each RTB and bypass RTB contains an undervoltage (UV) coil which when de-energized either by an automatic or manual RPS trip, cause the control rods to insert into the core. In addition, the main RTBs feature a shunt trip device, which applies DC power to trip the breaker on a manual or automatic trip signal, along with control board pushbutton circuits to energize the shunt trip. Either the undervoltage coil or the shunt trip mechanism is sufficient by itself, thus providing a diverse trip mechanism. Opening the RTBs locally is also available. Because the RPS is a de-energize-to-trip system, once a loss of power occurs to the reactor trip breakers undervoltage coils, the breakers open through spring force and will not reclose until manually reset.

As indicated in Table E1-1 of Enclosure 1, the RTBs are evaluated in the PRA.

Point Beach TS 3.3.1. Table 3.3-1, Condition Q, requires restoration of an inoperable RTB to OPERABLE status in MODES 1 and 2. STS 3.3.1. Table 3.3-1, Condition U, requires restoration of an inoperable RTB train to OPERABLE status in MODES 1 and 2. The trip function applies to the RTBs exclusive of the actual trip mechanisms. Since an inoperable RTB renders the RTB *train* inoperable, STS Condition U and Point Beach Condition Q are functionally equivalent. The plant specific variation is acceptable since the RTBs are evaluated in the PRA and the variation is inconsequential with regard to the application of the Point Beach RICT Program. Thereby Condition Q is appropriate for inclusion in the Point Beach RICT Program.

2) TS 3.3.2, Table 3.3-2, ESFAS Instrumentation Variations

i. Feedwater Isolation; Automatic Actuation Logic and Actuation Relays (FU5a)
Feedwater Isolation; SG Water Level - High (FU5b)

The ESFAS Feedwater Isolation Automatic Actuation Logic and Actuation Relays (FU5a) and Steam Generator (SG) Water Level - High (FU5b) trip functions serve to stop excessive feedwater flow into the SGs which could result in excessive cooldown of the primary system and feedwater carryover into the steam lines causing turbine damage. The ESFAS Feedwater Isolation SG high water level trip is actuated on either an SI signal or when the level in either SG exceeds the high-setpoint. The actuation logic and relays consist of all circuitry housed within the actuation subsystems, including the initiating relay contacts responsible for actuating the feedwater isolation equipment. The ESFAS Feedwater Isolation Automatic Actuation Logic and Actuation Relays and SG Water Level - High trip functions must be OPERABLE in MODES 1, 2, and 3 except when all Main Feedwater Regulating Valves (MFRVs), Main Feedwater Isolation Valves (MFIVs) and associated bypass valves are closed and de-activated.

The feedwater isolation signals for feedwater isolation rely on a 2-out-of-3 (either loop) high-steam generator level trip logic. Three SG water level sensors per SG provide input to the feedwater isolation trip functions. Since one of the three SG level channels is shared with the feedwater control function, a second failure must be assumed on the remaining channels according to the single failure rules of IEEE 279 (Reference 1). The second failure could defeat the feedwater isolation function by preventing a valid trip of the 2-out-of-3 coincidence logic, which violates IEEE 279. However, justification for maintaining the two-out-of-three Feedwater Isolation-SG Water Level-High function is provided in NUREG-1218 (Reference 4), which concluded that changes to improve the existing overfill-protection systems from a 2-out-of-3 to a 2-out-of-4 steam generator high-high water level trip does not

significantly reduce risk. NUREG 1218 resolved a generic control/protection interaction concern for Westinghouse PWRs by requiring the plant TS "include provisions to periodically verify the operability of overfill-protection systems and ensure automatic overfill-protection is provided at power operation." To satisfy this requirement, the Point Beach TS require quarterly testing of the steam generator level channels, including the feedwater isolation logic on high SG level.

As indicated in Table E1-1 of Enclosure 1, the ESFAS Feedwater Isolation Automatic Actuation Logic and Actuation Relays (FU5a) and Steam Generator (SG) Water Level - High (FU5b) trip functions are evaluated in the PRA by means of a surrogate which fails AFW initiation to conservatively bound the risk increase associated with these functions.

The Required Action for Point Beach TS 3.3.2, Table 3.3-2,Condition N, requires entry into MODE 3 within 6-hours and MODE 4 within 12-hours if the Completion Time is not met (unless the MFIVs, MFRVs and associated bypass valves are isolated and deactivated in MODES 2 or 3). In contrast, NUREG 1431, Revision 4, and thereby TSTF-505, Revision 2, does not require Mode 4 entry if the specified Completion Time is not met. The Point Beach TS end state (i.e. MODE 4) is appropriate since MODES 1, 2 and 3 are the applicable MODES for the feedwater isolation functions. In addition, the ESFAS Feedwater Isolation Automatic Actuation Logic and Actuation Relays (FU5a) and SG Water Level - High (FU5b) trip functions isolate feedwater upon a valid signal, whereas NUREG 1431, Revision 4, and thereby TSTF-505, Revision 2, specify a feedwater isolation and a turbine trip function. The Point Beach feedwater isolation signals do not initiate a turbine trip. Only the non-safety related ATWS Mitigating System Actuation Circuitry (AMSAC) function will trip the turbine (and initiate AFW) in the event of a total loss of main feedwater event without reactor/turbine trip. AMSAC was added to comply with the blackout rule requirements of 10 CFR 50.62. These plant-specific variations are acceptable since the Feedwater Isolation Automatic Actuation Logic and Actuation Relays (FU5a) and Steam Generator (SG) Water Level - High (FU5b) trip functions are adequately evaluated by means of a surrogate in the PRA and the variations are inconsequential to the application of the Point Beach RICT Program. Thereby, Condition N is appropriate for inclusion in the Point Beach RICT Program.

3) TS 3.6, Containment Systems Variations

   i. TS 3.6.3, Condition C - One or more penetration flow paths with one containment isolation valve inoperable.

The Containment Isolation System consists of containment isolation valves, flanges, etc., which form two barriers in series for each containment penetration such that no single credible failure or malfunction of an active barrier can result in a loss of isolation or leakage exceeding the limits assumed in the safety analyses. Each system having piping which penetrates the containment leakage limiting boundary is designed to maintain or establish isolation of the containment from the outside environment. Penetration design is such that two isolation barriers satisfying Point Beach GDC 53 (similar to Proposed 1967 GDC 53) are provided for each containment penetration and no single active failure prevents penetration isolation upon a valid containment isolation signal. No manual operation is required for immediate penetration isolation. Valves designed to close either automatically or manually (including check valves with flow through the valve not secured), are considered active barriers. Upon receipt of a containment isolation signal, these valves immediately isolate their associated containment penetration flowpaths to minimize leakage of fission products to the environment.

As indicated in Table E1-1 of Enclosure 1, the containment isolation system is evaluated in the PRA by means of a surrogate which fails the containment isolation logic to conservatively bound the risk increase associated with this function.

Point Beach TS 3.6.3, Condition C requires the containment penetration flowpath associated with an inoperable containment isolation valve to be isolated if the Completion Time is not met. Condition C

additionally requires the penetration flow path to be verified isolated every 31 days but limits the verification to isolation devices located outside containment. In contrast, the STS of NUREG-1431, Revision 4, and thereby TSTF-505, Revision 2, does not restrict the 31-day verification requirement to only containment isolation valves located outside containment. Similar to the administrative variations discussed in Section 2.4.1.3 of this amendment request, the 31-day surveillance limitation was an element retained from an earlier version of the Point Beach TS that was consistent with the licensing basis, but differed from NUREG-1431, Revision 1, the STS version upon which the Point Beach TS are based. The proposed change authorizes a RICT for isolation of the associated containment penetration but not for the performance of the 31-day penetration isolation verification requirement. The plant-specific variation is acceptable since the containment isolation system is adequately evaluated by means of a surrogate in the PRA and the 31-day isolation verification requirement is inconsequential to the implementation of the Point Beach RICT Program. Thereby, Condition C is appropriate for inclusion in the Point Beach RICT Program.

4) TS 3.7, Plant Systems Variations

i. TS 3.7.2 - MSIVs and Non-Return Check Valves

The main steam system conducts steam in a 30-inch pipe from each of the two steam generators within the reactor containment through a swing disc-type main steam isolation valve (MSIV) and a swing-disc type non-return check valve to the turbine stop and control valves. Each steam generator's steam line contains a MSIV outside containment and a non-return check valve further downstream to prevent blowdown from an intact steam generator through a ruptured main steam line. To mitigate a steam line break, the MSIVs close automatically following receipt of a safety injection (SI) signal coincident with a Hi-Hi steam flow signal. Under steam line break conditions, rapid MSIV closure is required to limit RCS cooldown and resulting reactivity addition to satisfy the accident analysis assumptions for core protection. Automatic MSIV closure also prevents the uncontrolled blowdown of more than one steam generator on a steam line break, assuming a coincident single failure of either MSIV or its associated non-return check valve to close. The MSIVs are also used to isolate the affected steam generator in the event of a steam generator tube rupture. The MSIVs are downstream from the main steam safety valves (MSSVs) and auxiliary feedwater (AFW) pump turbine steam supply, to prevent MSSV and AFW isolation from the steam generators by MSIV closure. Each MSIV swing disc valve is normally held out of the main steam flow path by an air piston and closed by spring force within five seconds when the air supply is shut off by the steam line break protection system. The non-return check valves, located downstream of the MSIVs, prevent a non-faulted steam generator from blowing down through a faulted main steam line by means of a cross-connection line between the two main steam headers that lies downstream of the non-return check valves. The non-return check valves close on reverse flow to prevent the blowdown of more than one steam generator in the event of a main steam line break coincident with the failure of a loop MSIV to close properly. Valve closure assures that for any steam break location coupled with an MSIV single failure, both steam generators will not blow down and cause core damage due to excess positive reactivity from the RCS cooldown transient. Separation between the MSIVs and the non-return check valves are such that any steam line failure would not cause simultaneous failure of the associated MSIV and non-return check valve.

As indicated in Table E1-1 of Enclosure 1, the MSIVs and Non-Return Check Valves are evaluated in the PRA.

Point Beach TS 3.7.2, Condition A, provides for one steam generator flowpath with one or more inoperable [MSIV or non-return check] valves. The MSIVs and the non-return check valves both perform a safety function to close to mitigate the effects of a main steam line break outside containment. With both the MSIV and the non-return check of the same steam generator flowpath inoperable, a non-faulted steam line cannot be isolated from a main steam line break outside containment, which constitutes a loss of function. To prevent the application of RICT to this loss of function condition, a

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note is proposed for Point Beach TS 3.7.2, Condition A, which limits the application of RICT to either one inoperable MSIV or one inoperable non-return check valve, but not both, in a steam generator flowpath. In contrast, the STS of NUREG-1431, Revision 4, and thereby TSTF-505, Revision 2, does not specify requirements for the non-return check valves. The plant-specific variation is acceptable since the MSIVs and the non-return check valves are evaluated in the PRA and the proposed note is consistent with the NRC's model safety evaluation (Reference 5) which, in Section 2.2.4.1, acknowledges the addition of a note to Required Actions as an acceptable method for limiting the application of RICTs to Required Action Conditions that result in a loss of function. Thereby the proposed Condition A is appropriate for inclusion in the Point Beach RICT Program.

ii. TS 3.7.7, Conditions A and B - CC pumps; CC heat exchangers

The component cooling (CC) water system removes heat from the reactor coolant system via the residual heat removal system during plant shutdown, cools the letdown flow to the chemical and volume control system during power operation and provides cooling to dissipate waste heat from various primary plant components. The system consists of four horizontal, centrifugal component cooling (CC) water pumps, four heat exchangers, two surge tanks and the piping, valves, instrumentation, and controls necessary to provide the heat removal capability to support the operation of the units and equipment. The component cooling water loop in each unit consists of two CC pumps, two heat exchangers, a surge tank, a supply header, and a return header. Normally, the component cooling loops of each unit operate independently such that two CC pumps and one CC heat exchanger are available for use, and two CC heat exchangers serve as shared standby units. The capability to use the CC pumps assigned to one loop to supply component cooling to both units is also provided. One CC pump and one heat exchanger are normally operated to provide cooling water for various components located in the auxiliary and containment buildings. The second CC pump is in standby and will auto-start on low discharge pressure. A second CC heat exchanger is normally aligned to the associated unit with component cooling flow cut in and service water isolated at the discharge. The automatic start function of the CC water pumps on low pressure is provided for operational convenience and is not relied upon by the safety analyses to mitigate accidents or events. Two CC pumps and two heat exchangers are used to remove the residual and sensible heat during plant shutdown. If one of the CC pumps or two of the CC heat exchangers are not operable, safe shutdown of the plant is not affected; however, the time for cooldown is extended. On loss of off-site power, the emergency diesel generators (EDGs) will automatically restore power to the safeguards buses which allows the associated CC pump to automatically restart unless the loss of power is coincident with a safety injection signal. The CC pumps will be stripped of power and will not automatically restart upon a safety injection signal coincident with a loss of voltage on the associated 480 VAC bus. The CC system is continuously monitored for radioactivity indicative of RCS or residual heat removal system in-leakage.

As indicated in Table E1-1 of Enclosure 1, CC system is evaluated in the PRA on a component level.

Point Beach TS 3.7.7, Conditions A and B, address the condition of an inoperable CC pump and an inoperable CC heat exchanger, respectively. In contrast, STS 3.7.7, Condition A, of NUREG-1431, and thereby TSTF-505, Revision 2, addresses the condition of an inoperable CC train. As explained above, an inoperable CC pump or heat exchanger does not necessarily render the associated CC train inoperable. Sufficient redundancy exists within each CC loop such that with a single inoperable CC pump or CC heat exchanger, 100% of the required cooling capacity can be provided during normal operations and post-accident conditions by the associated standby CC pumps and heat exchangers. The plant-specific variations are acceptable since the CC system is evaluated in the PRA and sufficient component-level redundancy exists to assure required peak cooling capacity under all plant conditions. Thereby Conditions A and B are appropriate for inclusion in the Point Beach RICT Program.

iii. TS 3.7.8, Conditions A, C and D, Service Water System [see diagram below]

The SW System provides a heat sink for the removal of process and operating heat from safety related components during a design basis accident or transient and additionally for non-safety related components during normal operation and normal shutdowns. The SW System is designed to perform its function with a single failure of any active component, assuming a loss of offsite power. A single common Service Water System for both units provides cooling water supplies to both safeguards and non-safety related balance of plant equipment using an open loop from and back to Lake Michigan. Redundancy in the system is provided by six motor-driven service water pumps powered from four different 480V safeguards buses on two units, by a single loop supply header for the two units, and by dual return pathways back to the lake by way of the circulating water return lines. Two service water pumps are connected to separate 480-volt buses (Unit 2 B03 and Unit 1 B04), one per bus. The four remaining pumps are connected, two per bus, to two separate 480-volt buses (Unit 1 B03 and Unit 2 B04). The Service Water system provides sufficient flow to the spent fuel pool heat exchangers to provide adequate heat removal of spent fuel decay heat. The SW System is also the required back-up water source for the Auxiliary Feedwater System. A safety injection signal from either unit, with or without a loss of offsite power, will send a start signal to all six Service Water pumps to accommodate immediate cooling for the emergency diesel generators. Current hydraulic modeling for accidents occurring during both units operating assume three pumps are available to provide flow to safety related loads of the affected unit, while maintaining the normal flow requirements of the unaffected unit.

Service Water System redundancy is provided by all six Service Water pumps feeding into a continuous discharge ‘ring’ header that effectively results in two Service Water flowpaths directing flow to both trains of all loads for both units. Using manual and motor-operated valves, the ring header continuous flowpath can be “broken” to perform maintenance on the Service Water strainers or to isolate one of the three supply headers that make up the ring. For maintenance purposes, all loads could be supplied from either the North or South Service Water header without losing redundancy as long as the ring header is intact (continuous flowpath in both directions around the ring). Isolation of any SW header will not impact the ability of the SW System to supply cooling water to the required number of essential loads of either unit. Safeguards loads, except for containment fan coolers, are fed from different portions of the Service Water loop - either the north, south or west header. In the normal alignment, only one of these supply pathways is in service at a time. Non-essential loads are supplied by five branches coming off of the ring header accompanied with redundant isolation valves that close upon receipt of an SI signal from either unit. During plant operations, the non-essential loads are normally supplied from the north and south sections of the ring header. Two operating Service Water pumps are sufficient to meet all the current design basis acceptance criteria provided the non-essential loads on the non-operating unit are isolated from the Service Water ring header; otherwise, a third Service Water pump is necessary to assure sufficient flow to monitored functions. Hence, operation of the Service Water System with five operable Service Water pumps for an indefinite period of time is allowed provided the system is in a configuration which ensures that all relevant design basis requirements are met while sustaining the most limiting single active failure, i.e. loss of the safeguards train supporting the start signal for three of the operable Service Water pumps. With one or more ring header isolation valves incapable of being closed, the SW System remains capable of providing the cooling water flow to required equipment. However, the ability to isolate a break in the system while continuing to provide cooling water to required equipment may be impaired. If multiple closed ring header isolation valves incapacitate SW flow to required equipment, entry would be made into the applicable TS Required Actions for the plant systems rendered inoperable.

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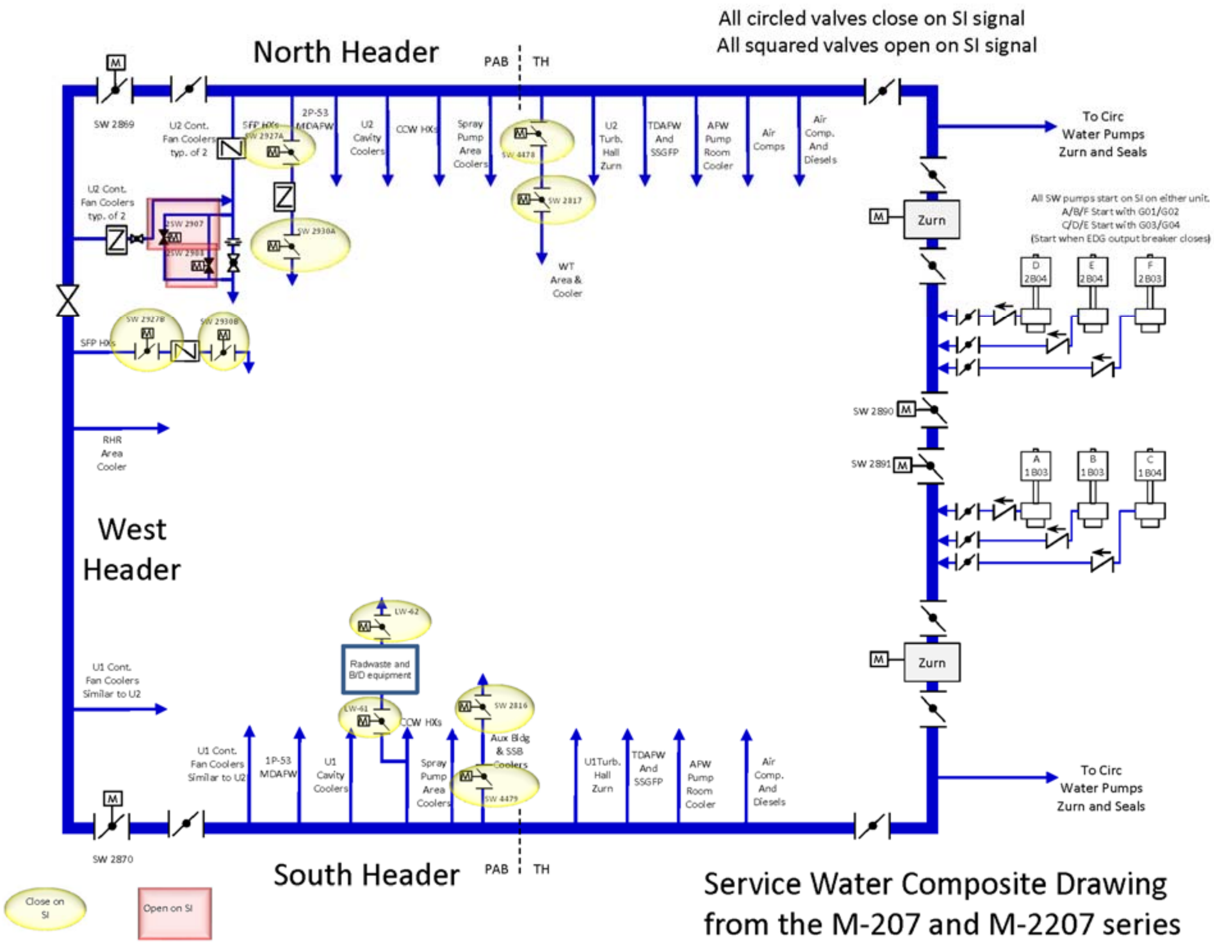

As indicated in Table E1-1 of Enclosure 1, the SW system is evaluated in the PRA on a component level.

- TS 3.7.8, Service Water System, Condition A

Point Beach TS 3.7.8, Condition A, addresses the condition of one inoperable Service Water (SW) pump with both units in MODES 1, 2, 3 or 4. TS 3.7.8, Condition A, deviates from STS 3.7.8, Condition A, of NUREG-1431, Revision 4, and thereby TSTF-505, Revision 2, which specifies requirements for an inoperable SW train (in lieu of a pump). Loss of a SW pump does not render the SW system incapable of performing its required function during normal operating or design basis accident conditions. As explained above, all six SW pumps feed into a continuous discharge ring header that effectively results in two SW flowpaths directing flow to both trains of all loads for both units. With one inoperable SW pump, failure of a safeguards train supporting the start signal for three of the operable SW pumps would leave two remaining operable SW pumps, which is sufficient to provide the heat sink for the safety related components on both units (i.e. assuming automatic isolation of the non-essential loads on the faulted unit). The plant-specific variation is acceptable since the SW system is evaluated in the PRA and an inoperable SW pump with both units in MODES 1, 2, 3, or 4 does not impair station response to a design basis accident given the availability of the other, operable SW pumps. Thereby, proposed Condition A is appropriate for inclusion in the Point Beach RICT Program.

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- TS 3.7.8, Service Water System, Condition C

Point Beach TS 3.7.8, Condition C addresses the condition of the SW ring header continuous flowpath interrupted. TS 3.7.8, Condition C deviates from STS 3.7.8, Condition C, of NUREG-1431, Revision 4, and thereby TSTF-505, Revision 2, which specifies requirements for an inoperable SW train. As described above, by employing system manual and automatic valves, during plant operation the ring header continuous flowpath can be interrupted for maintenance purposes during which all SW loads are supplied from either the north or south SW header without losing redundancy provided the ring header is intact in both directions around the ring. Isolation of any SW header will not impair the ability of the SW System to supply cooling water to the required number of essential loads on either unit. The plant-specific variation is acceptable since the SW system is evaluated in the PRA and SW flow to mitigating plant loads is unaffected by the SW ring header interrupted flowpath condition. Thereby proposed Condition C is appropriate for inclusion in the Point Beach RICT Program.

- TS 3.7.8, Service Water System, Condition D

Point Beach TS 3.7.8, Condition D addresses the condition of one or more non-essential-SW-load flowpath(s) with one required automatic isolation valve inoperable and the affected non-essential flowpath(s) not isolated. TS 3.7.8, Condition D deviates from STS 3.7.8, Condition C, of NUREG-1431, Revision 4, and thereby TSTF-505, Revision 2, which specifies requirements for an inoperable SW train. As described above, the non-essential loads are supplied by five branches coming off of the SW ring header accompanied with redundant isolation valves that close upon receipt of a safety injection signal from either unit. Hence, the condition of multiple non-essential SW load flowpaths, each with one required automatic isolation valve inoperable, would not necessitate additional operating SW pumps during plant operations or under worst-case design basis accident conditions since the affected non-essential SW load flowpaths remain capable of isolation by their redundant, operable automatic isolation valves. The plant-specific variation is acceptable since the SW system is evaluated in the PRA and the capacity of the SW system would be unaffected by single inoperable isolation valve(s) associated with a non-essential SW flowpath(s) during the extended period of inoperability allowed by a RICT. Thereby proposed Condition D is appropriate for inclusion in the Point Beach RICT Program.

5) TS 3.8, Electrical Power System Variations [see diagram below]

The Point Beach Class 1E AC Electrical Power Distribution System consists of the preferred normal offsite power source and the onsite standby emergency power sources. All electrical systems and components vital to plant safety, including the emergency diesel generators (EDGs), are designed as Class 1 and are capable of withstanding the maximum potential earthquake, windstorms, floods, or disturbances on the external electrical system. The Class 1E AC Electrical Power Distribution System is divided into two redundant load groups (safeguards buses) such that the loss of any one load group will not prevent performance of a safety function.

<u>345 KVAC System</u>

The normal offsite power source consists of the 345 KVAC System, which is common to both units. The 345 KVAC System supplies power to the 345 KVAC Offsite Transmission System (i.e., that part of the transmission system not within the Point Beach Switchyard) through four connected transmission lines. The 345 KVAC System satisfies the following criteria:

1) Auxiliary power shall be available for an orderly plant shutdown assuming a 345 KVAC bus or breaker forces a unit trip.

2) Two independent sources of offsite power shall be available to either unit such that a failure of any 345 KVAC bus or breaker shall not affect both sources of offsite power.

Evaluation of Plant-Specific Variations

The 345 KVAC System supports each unit's main generator 19 KVAC System by supplying power to main transformers X-01 and unit auxiliary transformers, X-02, which provide power to the non-safety related electrical loads on 4kV buses, A-01 and A-02 (see electrical diagram below). The 19 KVAC System connects to the 345 KVAC System by supplying power to the main transformer, X-01, via the unit's turbine generator when the associated 19kV main generator breaker is closed, which allows the power generated from the unit main generators to be transferred to the Northeast Wisconsin 345 KVAC transmission system. When the 19kV main generator breakers are open, power flows from the 345 KVAC System to 4.16 kV switchgear buses A01 and A02. During abnormal conditions the main transformers may be used to back-feed power from the switchyard buses to the safety related onsite electrical power system within established station operating procedure limitations.

<u>13.8 KVAC System</u>

The 345 KVAC System and the Gas Turbine (G05) are the sources of power to the 13.8 KVAC System which is the intermediate AC voltage power distribution system providing normal offsite power to the 4.16 kV safeguard buses during power operations and during plant startup, shutdown and following main generator trips. The 13.8 KVAC System is divided into three buses which are designated H01, H02, and H03. The H02 bus supplies Unit 1 by receiving power from the high voltage [345kV to 13.8kV] station auxiliary transformer, 1X03, and supplying low voltage [13.8kV to 4.16kV] station auxiliary transformer, 1X04. In a like manner, the H03 bus supplies Unit 2 and is normally served by the high voltage station auxiliary transformer, 2X03, to power low voltage station auxiliary transformer, 2X04. Bus H01 lies between H02 and H03, such that the units can be interconnected to alternate supplies by arranging bus tie breakers to connect H02 to H01 and H03 to H01. The H01, H02 and H03 bus configuration allows a high voltage station auxiliary transformer (X03) to be removed from service and its associated low voltage auxiliary transformer supplied via the H01 bus from the other unit's X03 transformer or Gas Turbine, G05. When a high voltage station transformer (X03) experiences a fault, the tie breakers between H02 and H01, and H03 and H01, receive an automatic transfer signal to restore power to the respective low voltage station transformer, X04. The 13.8 kV Gas Turbine Generator, G-05, is connected via a breaker to the H01 bus such that power can be delivered to either unit by arranging the H01, H02, and H03 13.8 kV tie breakers buses. In addition, a 3-phase, 15 MVAR capacitor bank is connected to 13.8 KVAC bus H01 such that aligning bus H01 to either bus H02 (Unit 1) or H03 (Unit 2) allows the capacitor bank to align to either unit's offsite connection. The 13.8 KVAC system also supplies safe-shutdown buses (via X08), as well as various plant support loads, G05 auxiliaries, switchyard auxiliaries, etc.

During normal, start-up, and shutdown conditions, the 13.8 KVAC System distributes power from the 345 KVAC System (and possibly gas turbine, G-05) to the 4.16 KVAC System by means of the low voltage station auxiliary transformers, X04, which power the auxiliary electrical loads through switching buses A03 and A04, which in turn power safety-related 4.16 kV buses, A05 and A06. During accident conditions, the 13.8 KVAC System acts as the first source of power to safety-related 4160 VAC buses A05 and A06. During start-up and shutdown, the 13.8 KVAC System distributes power from the 345 KVAC System to non-safety-related 4.16 kV buses A01 and A02, which are normally powered by the respective unit main generators during power operation or from the 345 KVAC System when the 19kV main generator breakers are open. In the event of inadequate grid voltage during normal operating conditions, the 13.8kV Capacitor Bank may be used to permit a lower offsite 345kV grid voltage while still maintaining adequate voltage at 4.16 kV safety buses, A-05 and A-06, to preclude actuation of the degraded grid relays and bus transfer to the emergency diesel generators. During normal conditions the 13.8 KVAC System may also be used to distribute peaking from the Gas Turbine Generator to the 345 KVAC transmission system. The 125 VDC System supplies control power to various 13.8 KVAC System components via 125 VDC buses and distribution panels.

Evaluation of Plant-Specific Variations

4160 VAC System

The 4160 VAC System distributes nominal 4.16 kV power to safety-related and non-safety-related loads for both Point Beach units. The system includes two safety-related buses, A05 (A train), and A06 (B train) and four non-safety-related buses (A01, A02, A03, A04) per nuclear unit. "Switching" busses, A03 and A04, power safeguards busses, A05 and A06, respectively, through manually closed tie breakers. Non-safety-related buses A01 and A02 can be powered from either the main generator, G01, via unit auxiliary transformer, X02, or an offsite power supply via the 4.16 kV switching buses, A03 and A04. In addition to being served by buses A03 and A04, safeguards buses A05 and A06 are directly served by the Train A and Train B emergency diesel generators, respectively. Buses A05 and A06 each serve one of two 4.16 kV to 480-volt station service transformers for the unit's 480-volt safeguards equipment and one of two safety injection pumps. Unit 1 bus A06 [1-A06] and Unit 2 bus A05 [2-A05] each serve one motor driven auxiliary feedwater pump. If either low voltage station auxiliary transformer 1-X04 or 2-X04 is removed from service, tie breakers between buses 1-A03 and 2-A03 and between 1-A04 and 2-A04 can be manually closed to provide 4.16 kV power from the other unit. Offsite power can also be provided to each unit's A03 and A04 buses from the A01 and A02 buses, respectively, by back feeding via the 345 KVAC System through high voltage main transformer, X01, and low voltage station auxiliary transformer, X02. A spare X04 transformer is maintained in a condition which will allow expeditious repair or replacement of 1-X04 or 2-X04.

Each unit's main generator serves as the main source of electrical power for the non-safety related 4.16 kV auxiliary loads during online operation where power is supplied to the via the 19 kV to 4.16 kV auxiliary transformer that is connected to the main leads from the unit's generator. Upon a generator trip, offsite auxiliary electric power is back fed from the 345 KVAC System via transformers X01 and X02. During unit operation, the output of the unit's main generator supplies power to the primary side of the unit auxiliary transformer (X02) which is directly connected to the 19 kV system bus between the generator output circuit breaker and the main step up transformer (X01). The 4.16 kV buses, A01 and A02, are then connected to the secondary side of the unit auxiliary transformer (X02) to power non-safety related auxiliary loads. All normal operating, non-safety related 4.16 kV auxiliaries are split between buses A01 and A02. In addition, buses A01 and A02 each serve one 4.16 kV to 480V station service transformer. Buses A0l and A03, or buses A02 and A04, can be tied together via bus tie breakers but are normally maintained open during power operations. During normal operating conditions, 4.16 kV switchgear Buses A01, A02, A03, A04 and connected circuit breakers distribute power and provide circuit protection to connected loads to ensure an adequate and reliable power supply to auxiliary equipment. During Station Blackout, 4.16 kV switchgear buses A03, A04, A05, and A06 and connected circuit breakers distribute power and provide circuit protection to the connected safe shutdown loads required to achieve and maintain safe shutdown. Following a turbine generator trip, the 19 kV main generator breaker opens and the auxiliary loads on the 4.16 kV non-safeguards buses are fed by the unit auxiliary transformer (X02) via the main transformer (X01) connection to the 345 KVAC System. Control power for the 4.16 kV breakers is obtained from the station batteries. During a loss of voltage on 4.16 kV buses A01 and A02, relays provide a signal to trip the loads supplied by these buses and to trip the reactor and start the steam driven and motor driven AFW pumps. During an underfrequency event on 4.16 kV buses A01 and A02, relays provide a signal to trip the loads supplied by these buses and to trip the RCP feeder breaker, which will cause a backup reactor trip.

During normal and accident conditions, safety-related 4.16 kV buses, A05 and A06, distribute power to the connected safety-related loads. During a degraded grid voltage sensed on a safety-related 4.16 kV bus, relays disconnect the bus from its offsite power supply to prevent operation of connected loads at damaging voltages. During a loss of voltage on a 4.16 kV safety-related bus, relays provide a signal to start the EDGs and transfer the bus to this emergency power supply. In the event of a power loss, station procedures provide guidance to restore electrical power to any 4.16 kV safety-related bus by any EDG, offsite power, cross-tying with the opposite unit's power supply, or employing the gas turbine. The alignment of alternate and emergency power sources to safety-related 4.16 kV buses, A05 and

A06, satisfies the design requirements for electrical system reliability and redundancy. The 4160 VAC System supports the reactor protection system (RPS) by providing underfrequency and undervoltage tripping of the reactor coolant pumps to initiate a reactor trip signal upon loss of non-safety-related 4.16 kV buses, as well as direct reactor trip on undervoltage of both non-safety-related buses A01 and A02.

Emergency Diesel Generators

The emergency diesel generator (EDG) configuration consists of four shared emergency diesel generators that directly supply the safety related 4.16 kV electrical distribution system. The EDGs are divided into trains, “A” and “B”. The train A EDGs, G-01 and G-02, are normally aligned as standby emergency power with G-01 to the Unit 1 train A 4.16 kV bus, 1A-05, and G-02 aligned to the Unit 2 train A 4.16 kV bus, 2A-05. Likewise, the train B EDGs are normally aligned as standby emergency power with G-03 to Unit 1 train B 4.16 kV bus, 1A-06, and G-04 to the Unit 2 train B 4.16 kV bus, 2A-06. G-01 will automatically provide power to 1A-05 if power is lost on 1A-05; G-02 will automatically provide power to 2A-05 if power is lost on 2A-05. G-01 may be manually connected to provide power to 2A-05, and G-02 may be manually connected to provide power to 1A-05. Additionally, if G-01 is out of service, G-02 may be placed in a connection mode that will allows automatic power to 1A-05 or 2A-05 or both, if either or both buses lose power. When G-02 is out of service, G-01 can be aligned in the same manner. EDGs G-03 and G-04 have similar alignment capabilities for the B train.

Each diesel has adequate capacity to supply the engineered safety features for the hypothetical accident in one unit and to allow the second unit to be placed in a safe shutdown condition in the event of loss of offsite electrical power. No accident is assumed in the second unit. Each diesel generator will be started upon the receipt of an undervoltage condition signal on either its primary or opposite unit same train 4.16 kV bus and re-energize its 4.16 kV bus. All four diesel generators will start when a safety injection (SI) signal is received from either unit. The EDGs are required to start and be ready for loading within 10 seconds after receiving a start signal. Sufficient fuel oil is maintained by each train to provide for a 6-day run of one EDG at rated design load.

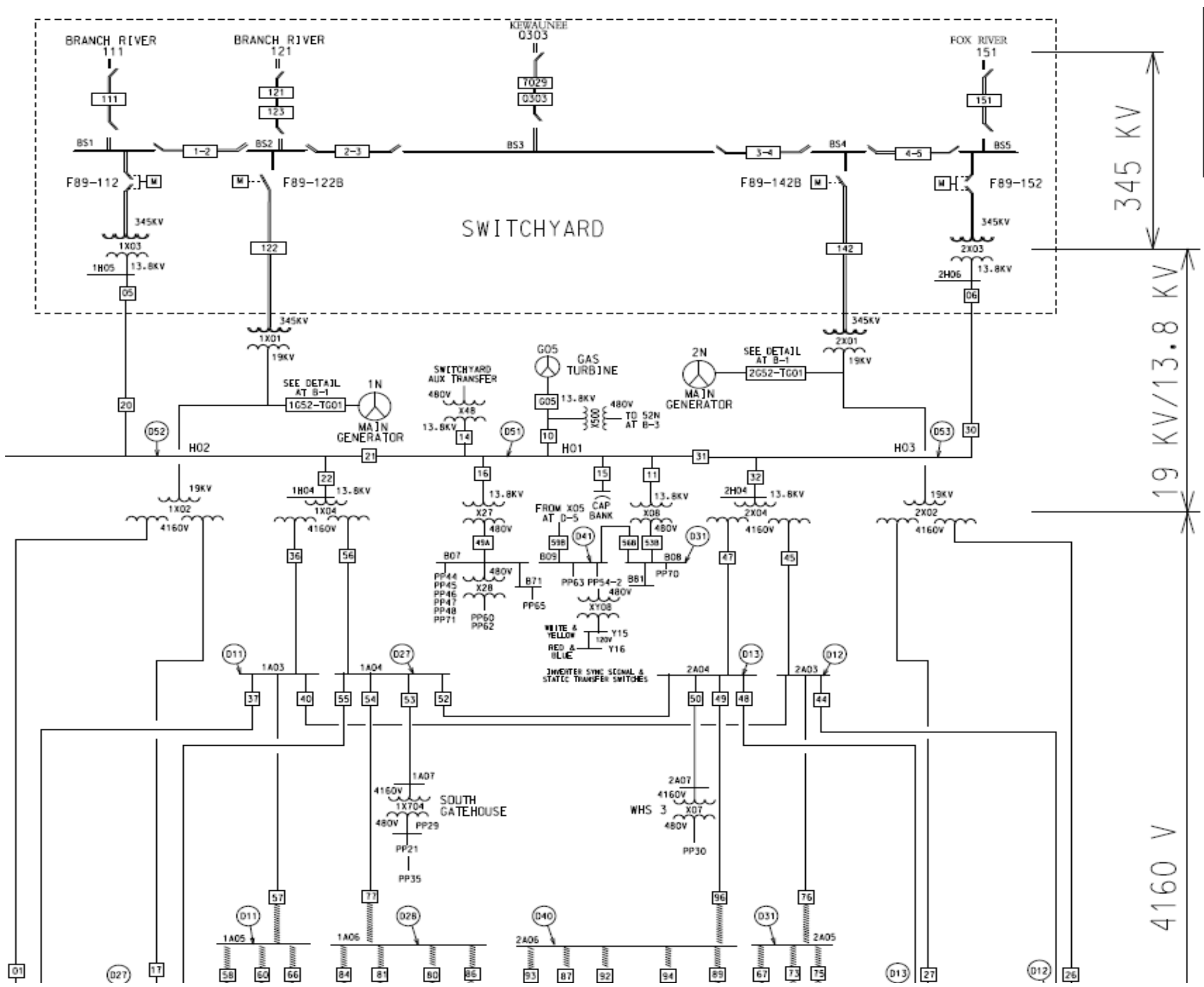
DC Electrical Power System

The 125 VDC Electrical Distribution system (125V) includes six separate, independent DC distribution buses, each capable of being connected to a common “swing” bus. The safety-related 125 VDC system consists of four main distribution buses: D-01, D-02, D-03, and D-04. The D-01 (train A) and D-02 (train B) main DC distribution buses supply power for control, emergency lighting, and two of the safety-related 20 VAC vital instrument bus inverters. The D-03 (train A) and D-04 (train B) main DC distribution buses supply power for control and two safety-related 120 VAC vital instrument bus inverters. Each of the four main distribution buses is powered by a battery charger (D-07, D-08, D-107 and D-108) and is backed up by a station battery (D-05, D-06, D-105, and D-106). The battery chargers supply their respective DC loads while maintaining the batteries at full charge. All of the battery chargers are powered from the 480 VAC system and are sized to recharge any of their respective partially discharged batteries within 24 hours while carrying normal loads.

Two safety-related swing DC distribution buses, D-301 and D-302, permit the connection of a swing battery and/or a swing charger to one of the four main distribution buses. The swing battery chargers and the swing battery allow the normally on-line battery chargers and batteries to be removed from service for maintenance that cannot be performed with the equipment on-line. Two swing battery chargers are available through one of the swing DC distribution buses. Swing charger D-09 is connected to swing DC distribution bus D-301 and can provide a source of DC power to distribution buses D-01 or D-02. Likewise, swing charger D-109 is connected to swing DC distribution bus D-302 and can provide a source of DC power to distribution buses D-03 or D-04. In addition, there exists a safety-related swing battery D-305 which is connected to swing DC distribution bus D-301 and is capable of being aligned to replace any of the four main distribution buses’ normal batteries.

Evaluation of Plant-Specific Variations

Safety related station batteries D-05, D-06, D-105, and D-106 are sized to carry their expected shutdown loads following a plant trip/LOCA and loss of offsite power or following a station blackout for a period of one hour. One battery charger is in service on each battery so that the batteries are always at full charge in anticipation of loss of AC power incident. During normal operation each safety-related DC bus supplies uninterruptible DC power of adequate voltage and quality to support systems that monitor for abnormal/accident conditions and initiate protective actions. During abnormal or emergency conditions, with or without a concurrent loss of offsite power, each safety-related DC bus supplies uninterruptible DC power of adequate voltage and quality to safety-related loads for accident mitigation.



As indicated in Table E1-1 of Enclosure 1, the 345 KVAC, 13.8 KVAC, 4160 VAC, EDGs and DC Electrical Power systems are evaluated in the PRA on a component level.

i. <u>TS 3.8.1, Conditions A, B and C</u>

Point Beach TS 3.8.1, Conditions A, B and C address the condition of an inoperable offsite power source through the loss of either the high-voltage transformer, X03, the loss of low-volage transformer, X04, or otherwise the loss of offsite power to the 4.16 kV safeguards busses, A05 and A06, each condition of which momentarily renders a loss of power to both train A and train B, 4.16 kV safeguards busses, A05 and A06, for the affected unit. Condition C also addresses the condition of a loss of offsite

power to 4.16 kV safeguards busses, A05 on Unit 1 and A06 on Unit 2, which power the train A and B motor-driven Auxiliary Feedwater (AFW) pumps, respectively. TS 3.8.1, Conditions A, B and C deviate from STS 3.8.1, Condition A, of NUREG-1431, Revision 4, and thereby of TSTF-505, Revision 2, which specifies requirements for an inoperable required offsite circuit, a Condition which would also render a loss of power 4.16 kV safeguards busses, A05 and A06. The plant-specific variations are acceptable since safeguards busses, A05 and A06, are evaluated in the PRA and sufficient redundancy and diversity exists to ensure that power to the safeguards busses is immediately restored in the event of a momentary loss. Such redundancy and diversity include the EDGs, each of which are capable of starting and supplying the power requirement of one complete set of safeguards equipment for one reactor unit while simultaneously providing sufficient power to allow the other unit to be placed in a safe shutdown condition (no accident is assumed on the second unit). Additional electrical system diversity includes 13.8 KVAC system capability to automatically switch power from the opposite unit via the H01, H02 and H03 interconnected tie breakers, the gas turbine G05, and back-feed capability of 4.16 kV power from the unit main transformer. Thereby, Conditions A, B and C are appropriate for inclusion in the Point Beach RICT Program.

ii. <u>TS 3.8.1, Condition D</u>

Point Beach TS 3.8.1, Condition D, addresses the condition of one or more required offsite power sources to one or more required Class 1E 4.16 kV busses inoperable. Condition D addresses the loss of the Train A 4.16 kV safeguards bus, A05, on one or both units, or the loss of the Train B 4.16 kV safeguards bus, A06, on one or both units, or the concurrent losses of A06 on Unit 1 and A05 on Unit 2. Any other combination of power losses to safeguard busses, A05 and A06, requires entry into Condition C. TS 3.8.1, Condition D, deviates from STS 3.8.1, Conditions A and C, of NUREG-1431, Revision 4, and thereby TSTF-505, Revision 2, which specifies requirements for one and two required offsite circuits inoperable, respectively. The Condition D allowance of more than one inoperable offsite power source to more than one required safeguard buss would not result in a loss of function given the redundancy and diversity in the 4.16 kV electrical power sources available to safeguard busses, A05 and A06, on either or both units, as described above for Conditions A, B and C. However, a note restricting the application of RICT to only one offsite power source affecting only one safeguards bus is proposed for Condition D to further assure electrical system reliability and functionality during the extended period of inoperability provided by a RICT. The plant-specific variation is acceptable since both safeguard busses are evaluated in the PRA and sufficient redundancy and diversity in 4.16 kV electrical power sources exist to ensure that power to the affected safeguards busses can be promptly restored in the event of a momentary power loss. Thereby, the proposed Condition D is appropriate for inclusion in the Point Beach RICT Program.

iii. <u>TS 3.8.1, Condition F</u>

Point Beach TS 3.8.1, Condition F, addresses the condition of one or more required offsite power sources to one or more required Class 1E 4.16 kV safeguard bus(es) inoperable and standby emergency power to redundant equipment inoperable. Condition F would apply to 4.16 kV safeguards buses on one or both units affected by one or more inoperable offsite power supplies with their respective redundant loads incapable of being power by an EDG. The Condition could support a loss of function due to the inability to repower affected safety-related equipment by means of an EDG on one or both units. A note is proposed for Condition F restricting the application of RICT to only one offsite power source affecting only one safeguards bus to further assure electrical system reliability and functionality during the extended period of inoperability provided by a RICT. The plant-specific variation is acceptable since both safeguard busses and EDGs are evaluated in the PRA and sufficient redundancy and diversity in 4.16 kV electrical power sources exist to ensure that power to the affected, safety-related plant loads can be restored in the event of a power loss. Thereby, the proposed Condition F is appropriate for inclusion in the Point Beach RICT Program.

Evaluation of Plant-Specific Variations

iv. TS 3.8.4, Condition A

Point Beach TS 3.8.4, Condition A, addresses the condition of one DC electrical power subsystem inoperable. TS 3.8.4, Condition A, deviates from STS 3.8.4, Condition C, of NUREG-1431, Revision 4, and thereby TSTF-505, Revision 2, which specify requirements for one inoperable DC electrical power subsystem exclusive of STS 3.8.4, Conditions A and B, which address one [or two] inoperable battery chargers and one [or two] inoperable batteries, respectively. The absence of a Point Beach TS Condition explicitly addressing inoperable DC batteries or battery chargers subjects an inoperable battery and battery charger to Point Beach TS 3.8.4, Condition A, in addition to all other components that comprise a DC electrical power subsystem. If one or more of the required components of a DC electrical power subsystem is inoperable, the redundant DC electrical power subsystems, including the safety-related swing busses, have the capability and required capacity to support safe shutdown and accident mitigation. The plant-specific variation is acceptable since the 125 VDC electrical power system is evaluated in the PRA and sufficient system redundancy exists to ensure that DC electrical power is provided for both normal and emergency applications. Thereby, Condition A is appropriate for inclusion in the Point Beach RICT Program.

References:

1) IEEE Standard 279 - 1968. (IEEE Std 279-1968), Proposed IEEE Criteria for Nuclear Power Plant Protection Systems, Approval Date: August 30, 1968

2) NRC NUREG-1431, Volume 1, “Standard Technical Specifications Westinghouse Plants”, Revision 4, dated April 3, 2012 (ADAMS Accession No. ML12100A222)

3) NRC NUREG-1431, Volume 1, “Standard Technical Specifications Westinghouse Plants”, Revision 1, dated April 30, 1995 (ADAMS Accession No. ML13196A405)

4) NUREG-1218, Regulatory Analysis of Unresolved Safety Issue A-47. Safety Implications of Control Systems in LWR Nuclear Power Plants, July 1989

5) NRC Safety Evaluation, “Final Revised Model Safety Evaluation of Traveler TSTF-505, Revision 2, ‘Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b’”, dated November 21, 2018 (ADAMS Accession No. ML18269A041)