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10CFR50.36

U-603859
May 23, 2008

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

Clinton Power Station, Unit 1
Facility Operating License
NRC Docket No. 50-461

Subject: Transmittal of Revision 11 to the Clinton Power Station Technical Specification Bases

In accordance with Clinton Power Station (CPS) Technical Specification 5.5.11, "Technical Specification (TS) Bases Control Program," AmerGen Energy Company (AmerGen), LLC is transmitting the revised pages constituting Revision 11 to the CPS TS Bases. The changes associated with this revision were processed in accordance with CPS TS 5.5.11, which became effective with Amendment No. 95 to the CPS Operating License. Compliance with CPS TS 5.5.11 requires updates to the TS Bases to be submitted to the NRC at a frequency consistent with 10CFR50.71, "Maintenance of records, making of reports," paragraph (e).

There are no regulatory commitments in this letter.

Should you have any questions concerning this information, please contact Mr. Jim Peterson at (217) 937-2810.

Respectfully,

Steven A. Gackstetter
Regulatory Assurance Manager
Clinton Power Station

JLP/blf

Attachment – Revision 11 to the CPS Technical Specification Bases

A001
NRR

cc: Regional Administrator – NRC Region III
NRC Senior Resident Inspector – Clinton Power Station
Illinois Emergency Management Agency – Division of Nuclear Safety

Attachment
Clinton Power Station, Unit 1
Revision 11 to the CPS Technical Specification Bases

Page Listing

ii	B 3.1-26	B 3.3-39a	B 3.3-39b
B 3.3-39c	B 3.3-39d	B 3.3-39e	B 3.3-39f
B 3.3-39g	B 3.3-39h	B 3.4-3	B 3.4-4
B 3.4-5	B 3.4-6	B 3.4-7	B 3.4-8
B 3.4-32	B 3.5-22	B 3.5-26	B 3.6-1
B 3.6-2	B 3.6-27	B 3.6-86	B 3.6-88
B 3.6-88a	B 3.7-25	B 3.8-46	B 3.8-48a
B 3.8-71	B 3.8-71a	B 3.8-71b	

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.4.2

Additional testing of a sample of control rods is required to verify the continued performance of the scram function during the cycle. A representative sample contains at least 10% of the control rods. The sample remains "representative" if no more than 7.5% of the control rods in the tested sample are determined to be "slow." If more than 7.5% of the sample is declared to be "slow" per the criteria in Table 3.1.4-1, additional control rods are tested until this 7.5% criterion (i.e., 7.5% of the entire sample size) is satisfied, or until the total number of "slow" control rods throughout the core, from all surveillances) exceed the LCO limit. For planned testing, the control rods selected for the sample should be different for each test. Data from inadvertent scrams should be used whenever possible to avoid unnecessary testing at power, even if the control rods with data were previously tested in a sample. The 200 day Frequency is based on operating experience that has shown control rod scram times do not significantly change over an operating cycle. This Frequency is also reasonable, based on the additional Surveillances done on the CRDs at more frequent intervals in accordance with LCO 3.1.3 and LCO 3.1.5, "Control Rod Scram Accumulators."

With regard to scram time values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 8).

SR 3.1.4.3

When work that could affect the scram insertion time is performed on a control rod or the CRD System, testing must be done to demonstrate that each affected control rod retains adequate scram performance over the range of applicable reactor pressures from zero to the maximum permissible pressure. The scram testing must be performed once before declaring the control rod OPERABLE. The required scram time testing must demonstrate that the affected control rod is still within acceptable limits by demonstrating an acceptable scram insertion time to notch position 13. The scram time acceptance criteria for this alternate test shall be determined by linear interpolation between 0.95 seconds at a reactor coolant pressure of 0 psig and 1.40 seconds at 950 psig. The limits for reactor pressures < 950 psig are established based on a high

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B 3.3 INSTRUMENTATION

B 3.3.1.3 Oscillation Power Range Monitor (OPRM) Instrumentation

BASES

BACKGROUND

General Design Criterion 10 (GDC 10) requires the reactor core and associated coolant, control, and protection systems to be designed with appropriate margin to assure that acceptable fuel design limits are not exceeded during any condition of normal operation, including the affects of anticipated operational occurrences. Additionally, GDC 12 requires the reactor core and associated coolant, control, and protection systems to be designed to assure that power oscillations which can result in conditions exceeding acceptable fuel design limits are either not possible or can be reliably and readily detected and suppressed. The OPRM System provides compliance with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel Minimum Critical Power Ratio (MCPR) safety limit.

References 1, 2, and 3 describe three separate algorithms for detecting stability related oscillations: the period based detection algorithm, the amplitude based algorithm, and the growth rate algorithm. The OPRM System hardware implements these algorithms in microprocessor based modules. These modules execute the algorithms based on Local Power Range Monitor (LPRM) inputs and generate alarms and trips based on these calculations. These trips result in tripping the Reactor Protection System (RPS) when the appropriate RPS trip logic is satisfied, as described in the Bases for LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation." Only the period based detection algorithm is used in the safety analysis (Ref. 1, 2, 6, and 7). The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations.

The period based detection algorithm detects a stability related oscillation based on the occurrence of a fixed number of consecutive LPRM signal period confirmations coincident with the LPRM signal peak to average amplitude exceeding a specified setpoint.

Upon detection of a stability related oscillation, a trip is generated for that OPRM channel.

The OPRM System consists of 4 OPRM trip channels, each channel consisting of two OPRM modules. Each OPRM module receives input from LPRMs. Each OPRM module also receives input from the Neutron Monitoring System (NMS) Average Power Range Monitor (APRM) power and flow signals to automatically enable the trip function of the OPRM module.

Each OPRM module is continuously tested by a self-test function. On detection of any OPRM module failure, either a

(continued)

BASES

BACKGROUND (continued)

Trouble alarm or INOP alarm is activated. The OPRM module provides an INOP alarm when the self-test feature indicates that the OPRM module may not be capable of meeting its functional requirements.

APPLICABLE SAFETY ANALYSES

It has been shown that BWR cores may exhibit thermal-hydraulic reactor instabilities in high power and low flow portions of the core power to flow operating domain (Reference 4). GDC 10 requires the reactor core and associated coolant, control, and protection systems to be designed with appropriate margin to assure that acceptable fuel design limits are not exceeded during any condition of normal operation, including the affects of anticipated operational occurrences. GDC 12 requires assurance that power oscillations which can result in conditions exceeding acceptable fuel design limits are either not possible or can be reliably and readily detected and suppressed. The OPRM System provides compliance with GDC 10 and GDC 12 by detecting the onset of oscillations and suppressing them by initiating a reactor scram. This assures that the MCPR safety limit will not be violated for anticipated oscillations.

The OPRM Instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

The OPERABILITY of the OPRM System is dependent on the OPERABILITY of the four individual instrumentation channels with their setpoints within the specified nominal setpoint. Each channel must also respond within its assumed response time.

The nominal setpoints for the OPRM Period Based Trip Function are specified in the Core Operating Limits Report. The trip setpoints are treated as nominal setpoints and do not require additional allowances for uncertainty.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter value and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state.

The OPRM period based setpoint is determined by cycle specific analysis based on positive margin between the Safety Limit MCPR and the Operating Limit MCPR minus the change in CPR (ΔCPR). This methodology was approved for use by the NRC in Reference 6.

(continued)

BASES (continued)

LCO

Four channels of the OPRM System are required to be OPERABLE to ensure that stability related oscillations are detected and suppressed prior to exceeding the MCPR safety limit. Only one of the two OPRM modules (with an active period based detection algorithm) is required for OPRM channel OPERABILITY. The minimum number of LPRMs required OPERABLE to maintain an OPRM channel OPERABLE is consistent with the minimum number of LPRMs required to maintain the APRM System OPERABLE per LCO 3.3.1.1.

APPLICABILITY

The OPRM instrumentation is required to be OPERABLE in order to detect and suppress neutron flux oscillations in the event of thermal-hydraulic instability. As described in References 1, 2, 3, and 10, the region of anticipated oscillation is defined by THERMAL POWER ≥ 25% Rated Thermal Power (RTP) and recirculation drive flow is ≤ the value corresponding to 60% of rated core flow. The OPRM trip is required to be enabled in this region, and the OPRM must be capable of enabling the trip function as a result of anticipated transients that place the core in that power/flow condition. Therefore, the OPRM instrumentation is required to be OPERABLE with THERMAL POWER ≥ 21.6% RTP. It is not necessary for the OPRM instrumentation to be OPERABLE with THERMAL POWER < 21.6% RTP because the MCPR safety limit is not applicable below 21.6% RTP.

ACTIONS

A Note has been provided to modify the ACTIONS related to the OPRM instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable OPRM instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable OPRM instrumentation channel.

With respect to this Technical Specification, an RPS trip system is equivalent to an RPS division.

A.1, A.2, and A.3

Because of the reliability and on-line self-testing of the OPRM instrumentation and the redundancy of the RPS design, an allowable out of service time of 30 days has been shown to be acceptable (Ref. 7) to permit restoration of any

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the OPRM instrumentation still maintains OPRM trip capability (refer to Required Actions B.1 and B.2). The remaining OPERABLE OPRM channels continue to provide trip capability (see Condition B) and provide operator information relative to stability activity. The remaining OPRM modules have high reliability. With this high reliability, there is a low probability of a subsequent channel failure within the allowable out of service time. In addition, the OPRM modules continue to perform on-line self-testing and alert the operator if any further system degradation occurs.

If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the OPRM channel or associated RPS trip system must be placed in the tripped condition per Required Actions A.1 and A.2. Placing the inoperable OPRM channel in trip (or the associated RPS trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the OPRM channel (or RPS trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), the alternate method of detecting and suppressing thermal-hydraulic instability oscillations is required (Required Action A.3). This alternate method is described in Reference 5. It consists of avoidance of the region where oscillations are possible, exiting this region if it is entered due to unforeseen circumstances, and increased operator awareness and monitoring for neutron flux oscillations while taking action to exit the region. If indications of oscillation, as described in Reference 5, are observed by the operator, the operator will take the actions described by procedures, which include initiating a manual scram of the reactor. Continued operation with one OPRM channel inoperable, but not tripped, is permissible if the OPRM System maintains trip capability, since the combination of the alternate method and the OPRM trip capability provides adequate protection against oscillations.

B.1 and B.2

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped OPRM channels result in not maintaining OPRM trip capability. OPRM trip capability is considered to be maintained when sufficient OPRM channels are OPERABLE or in trip (or the associated RPS Division is in trip), such that a valid OPRM signal will generate a full RPS scram. This would require either 1) 2 OPERABLE OPRM channels capable of processing a trip thru to the RPS system, or 2) 1 OPERABLE OPRM channel and either 1 OPRM channel in trip or an RPS Division in

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

trip. These must be in a combination that will ultimately provide the required 2 inputs to RPS needed to initiate a full scram signal.

Because of the low probability of the occurrence of an instability, 12 hours is an acceptable time to initiate the alternate method of detecting and suppressing thermal-hydraulic instability oscillations described in the Bases for Action A.3 above. The alternate method of detecting and suppressing thermal-hydraulic instability oscillations avoids the region where oscillations are possible and would adequately address detection and mitigation in the event of instability oscillations. Based on industry operating experience with actual instability oscillations, the operator would be able to recognize instabilities during this time and take action to suppress them through a manual scram. In addition, the OPRM System may still be available to provide alarms to the operator if the onset of oscillations were to occur. Since plant operation is minimized in areas where oscillations may occur, operation for 120 days without OPRM trip capability is considered acceptable with implementation of an alternate method of detecting and suppressing thermal-hydraulic instability oscillations.

C.1

With any Required Action and associated Completion Time not met, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 21.6% RTP within 4 hours. Reducing THERMAL POWER to < 21.6% RTP places the plant in a region where instabilities cannot occur. The 4 hours is reasonable, based on operating experience, to reduce THERMAL POWER < 21.6% RTP from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that, when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the RPS reliability analysis (Ref. 9) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RPS will trip when necessary.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

For the following OPRM instrumentation Surveillances, both OPRM modules are tested, although only one is required to satisfy the Surveillance Requirement.

SR 3.3.1.3.1

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A Frequency of 184 days provides an acceptable level of system average unavailability over the Frequency interval and is based on the reliability of the channel (Reference 7).

SR 3.3.1.3.2

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the APRM System. The 1000 MWD/T Frequency is based on operating experience with LPRM sensitivity changes.

SR 3.3.1.3.3

The CHANNEL CALIBRATION is a complete check of the instrument loop. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations, consistent with the plant specific setpoint methodology. Calibration of the channel provides a check of the internal reference voltage and the internal processor clock frequency. It also compares the desired trip setpoint with those in the processor memory. Since the OPRM is a digital system, the internal reference voltage and processor clock frequency are, in turn, used to automatically calibrate the internal analog to digital converters. The nominal setpoints for the period based detection algorithm are specified in the Core Operating Limits Report (COLR). As noted, neutron detectors are excluded from CHANNEL CALIBRATION because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the 1000 MWD/T LPRM calibration against the TIPs (SR 3.3.1.1.8). SR 3.3.1.1.8 thus also ensures the operability of the OPRM instrumentation.

The nominal setpoints for the OPRM trip function for the period based detection algorithm (PBDA) are specified in the COLR. The PBDA trip setpoints are the number of confirmation counts required to permit a trip signal and the peak to average amplitude required to generate a trip signal.

The Frequency of 24 months is based upon the assumption of the magnitude of equipment drift provided by the equipment supplier (Reference 7).

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.3.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods in LCO 3.1.3, "Control Rod OPRABILITY," and scram discharge volume (SDV) vent and drain valves in LCO 3.1.8, "Scram Discharge Volume (SDV) Vent and Drain Valves," overlaps this Surveillance to provide complete testing of the assumed safety function. The OPRM self-test function may be utilized to perform this testing for those components that it is designed to monitor.

The 24 month Frequency is based on engineering judgement and reliability of the components. Operating experience has shown these components usually pass the surveillance when performed at the 24 month Frequency.

SR 3.3.1.3.5

This SR ensures that trips initiated from the OPRM System will not be inadvertently bypassed when THERMAL POWER is ≥ 25% RTP and recirculation drive flow is ≤ the value corresponding to 60% of rated core flow. This normally involves calibration of the bypass channels. The 25% RTP value is the plant specific value for the enable region, as described in Reference 10.

These values have been conservatively selected so that specific, additional uncertainty allowances need not be applied. Specifically, for the THERMAL POWER, the Average Power Range Monitor (APRM) establishes the reference signal to enable the OPRM System at 25% RTP. Thus, the nominal setpoints corresponding to the values listed above (25% RTP and the value corresponding to 60% of rated core flow) will be used to establish the enabled region of the OPRM System trips. (References 1, 2, 6, 10, and 11)

The Frequency of 24 months is based on engineering judgement, high reliability of the components, and operating experience.

SR 3.3.1.3.6

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis (Reference 6). The OPRM self-test function may be utilized to perform this testing for those components it is designed to monitor. The RPS RESPONSE TIME acceptance criteria are included in plant Surveillance procedures.

As noted, neutron detectors are excluded from RPS RESPONSE TIME testing because the principles of detector operation

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.3.6 (continued)

virtually ensure an instantaneous response time. RPS RESPONSE TIME tests are conducted on an 24 month STAGGERED TEST BASIS. This Frequency is consistent with the refueling cycle and is based upon operating experience, which shows that random failures of instrumentation components causing serious time degradation, but not channel failure, are infrequent.

REFERENCES

1. NEDO-31960, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," June 1991.

2. NEDO-31960, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," Supplement 1, March 1992.

3. NRC Letter, A. Thadani to L. A. England, "Acceptance for Referencing of Topical Reports NEDO-31960, Supplement 1, 'BWR Owners' Group Long-Term Stability Solutions Licensing Methodology'," July 12, 1994.

4. Generic Letter 94-02, "Long-Term Solutions and Upgrade of Interim Operating Recommendations for Thermal-Hydraulic Instabilities in Boiling Water Reactors," July 11, 1994.

5. BWROG Letter BWROG-94079, "Guidelines for Stability Interim Corrective Action," June 6, 1994.

6. NEDO-32465-A, "BWR Owners' Group Reactor Stability Detect and Suppress Solution Licensing Basis Methodology and reload Application," August 1996.

7. CENPD-400-P, Rev. 01, "Generic Topical Report for the ABB Option III Oscillation Power Range Monitor (OPRM)," May 1995.

8. NRC Letter, B. Boger to R. Pinelli, "Acceptance of Licensing Topical Report CENPD-400-P, 'Generic Topical Report for the ABB Option III Oscillation Power Range Monitor (OPRM)'," August 16, 1995.

9. NEDO-30851-P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.

10. NEDC-32989P, "Safety Analysis Report for Clinton Power Station Extended Power Uprate," dated June 2001.

11. Letter from K. P. Donovan (BWR Owners' Group) to U. S. NRC, "Guidelines for Stability Option III 'Enabled Region'," dated September 17, 1996.

BASES

APPLICABLE SAFETY ANALYSES (continued)	operating at the lower flow rate), a small mismatch has been determined to be acceptable based on engineering judgement. The recirculation system is also assumed to have sufficient flow coastdown characteristics to maintain fuel thermal margins during abnormal operational occurrences (AOOs) (Ref. 2), which are analyzed in Chapter 15 of the USAR. A plant specific LOCA analysis has been performed assuming only one operating recirculation loop. This analysis has demonstrated that, in the event of a LOCA caused by a pipe break in the operating recirculation loop, the Emergency Core Cooling System response will provide adequate core cooling, provided the APLHGR requirements are modified accordingly (Refs. 3 and 5). The transient analyses of Chapter 15 of the USAR have also been performed for single recirculation loop operation (Ref. 3) and demonstrate sufficient flow coastdown characteristics to maintain fuel thermal margins during the abnormal operational transients analyzed provided the MCPR, APLHGR and LHGR requirements are modified. During single recirculation loop operation, modification to the Reactor Protection System average power range monitor (APRM) instrument setpoints is also required to account for the different relationships between recirculation drive flow and reactor core flow. The MCPR, APLHGR and LHGR limits for single loop operation are specified in the COLR. The APRM flow biased simulated thermal power setpoint is in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation." Recirculation loops operating satisfies Criterion 2 of the NRC Policy Statement.
LCO	Two recirculation loops are normally required to be in operation with their flows matched within the limits specified in SR 3.4.1.1 to ensure that during a LOCA caused by a break of the piping of one recirculation loop the assumptions of the LOCA analysis are satisfied. Alternatively, with only one recirculation loop in operation, THERMAL POWER must be ≤ 58% RTP,

(continued)

BASES

LCO (continued)

and modifications to the required APLHGR limits (LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"), MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)"), LHGR limits (LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)"), and APRM Flow Biased Simulated Thermal Power—High setpoint (LCO 3.3.1.1) must be applied to allow continued operation consistent with the assumptions of References 3 and 5.

APPLICABILITY

In MODES 1 and 2, requirements for operation of the Reactor Coolant Recirculation System are necessary since there is considerable energy in the reactor core and the limiting AOOs and LOCAs are assumed to occur.

In MODES 3, 4, and 5, the consequences of an accident or AOO are reduced and the coastdown characteristics of the recirculation loops are not important.

ACTIONS

A.1

With both recirculation loops operating but the flows not matched, the recirculation loops must be restored to operation with matched flows within 2 hours. If the flow mismatch cannot be restored to within limits within 2 hours, one recirculation loop must be shut down.

(continued)

BASES

ACTIONS

A.1 (continued)

Alternatively, if the single loop requirements of the LCO are applied to operating limits and RPS setpoints, operation with only one recirculation loop would satisfy the requirements of the LCO and the initial conditions of the accident sequence.

The 2 hour Completion Time is based on the low probability of an accident occurring during this time period, on a reasonable time to complete the Required Action, and on frequent core monitoring by operators allowing abrupt changes in core flow conditions to be quickly detected.

(continued)

BASES

ACTIONS (continued)

B.1

Should a LOCA occur with THERMAL POWER > 58% RTP during single loop operation, the core response may not be bounded by the LOCA analyses. Therefore, only a limited time is allowed to reduce THERMAL POWER TO ≤ 58% RTP.

The 4 hour Completion Time is based on the low probability of an accident occurring during this time period, on a reasonable time to complete the Required Action, and on frequent core monitoring by the operators allowing changes in THERMAL POWER conditions to be quickly detected.

C.1

If the required limit or setpoint modifications for single loop operation (i.e., LCO requirements B.2 and B.3) are not met after transition from two recirculation loop operation to single recirculation loop operation, then the requirements of the LCO must be satisfied within 24 hours. The 24 hour Completion Time of the Condition provides time before the required modifications to required limits and setpoints have to be in effect after a change in the reactor operating conditions from two recirculation loops operating to single recirculation loop operation. This time is provided due to the need to stabilize operation with one recirculation loop, including the procedural steps necessary to limit flow and adjust the flow control mode in the operating loop, and the complexity and detail required to fully implement and confirm the required limit and setpoint modifications. The 24 hour Completion Time is also based on the low probability of an accident occurring during this period, on a reasonable time to complete the Required Action, and on frequent monitoring by operators allowing abrupt changes in core flow conditions to be quickly detected.

(continued)

BASES

ACTIONS (continued)

D.1

With no recirculation loops in operation, or the Required Action and associated Completion Time of Conditions A, B, or C not met, the unit is required to be brought to a MODE in which the LCO does not apply. The plant is required to be placed in MODE 3 in 12 hours. In this condition, the recirculation loops are not required to be operating because of the reduced severity of DBAs and minimal dependence on the recirculation loop coastdown characteristics. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

This SR ensures the recirculation loop flows are within the allowable limits for mismatch. At low core flow (i.e., < 70% of rated core flow), the MCPR requirements provide larger margins to the fuel cladding integrity Safety Limit such that the potential adverse effect of early boiling transition during a LOCA is reduced. A larger flow mismatch can therefore be allowed when core flow is < 70% of rated core flow. The recirculation loop jet pump flow, as used in this Surveillance, is the summation of the flows from all of the jet pumps associated with a single recirculation loop.

The mismatch is measured in terms of percent of rated core flow. This SR is not required when both loops are not in operation since the mismatch limits are meaningless during single loop or natural circulation operation. The Surveillance must be performed within 24 hours after both loops are in operation. The 24 hour Frequency is consistent with the Frequency for jet pump OPERABILITY verification and has been shown by operating experience to be adequate to detect off normal jet pump loop flows in a timely manner.

With regard to recirculation loop flow values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 4).

(continued)

BASES (continued)

REFERENCES

1. USAR, Section 6.3.3.7.
2. USAR, Section 5.4.1.1.
3. USAR, Chapter 15, Appendix 15B.
4. Calculation IP-0-0029.
5. "Clinton Power Station SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," NEDC-32945P, June 2000

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

Performance of leakage testing on each RCS PIV is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm per inch of nominal valve diameter up to 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition. For the two PIVs in series, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. If the PIVs are not individually leakage tested, one valve may have failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

The Frequency required by the Inservice Testing Program is within the ASME Code, Section XI, Frequency requirement and is based on the need to perform this surveillance under the conditions that apply during an outage and the potential for an unplanned transient if the surveillance were performed with the reactor at power.

Therefore, this SR is modified by a Note that states the leakage Surveillance is not required to be performed in MODE 3. Entry into MODE 3 is permitted for leakage testing at high differential pressures with stable conditions not possible in the lower MODES.

With regard to leakage values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 9).

(continued)

BASES

BACKGROUND (continued)	The RCIC pump is provided with a minimum flow bypass line, which discharges to the suppression pool. The valve in this line automatically opens to prevent pump damage due to overheating when other discharge line valves are closed. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, the RCIC System discharge line "keep fill" system is designed to maintain the pump discharge line filled with water.
APPLICABLE SAFETY ANALYSES	The function of the RCIC System is to respond to transient events by providing makeup coolant to the reactor. The RCIC System is not an Engineered Safety Feature and no credit is taken in the safety analysis for RCIC System operation. The RCIC System satisfies Criterion 4 of the NRC Policy Statement.
LCO	The OPERABILITY of the RCIC System provides adequate core cooling such that actuation of any of the ECCS subsystems is not required in the event of RPV isolation accompanied by a loss of feedwater flow. The RCIC System has sufficient capacity to maintain RPV inventory during an isolation event.
APPLICABILITY	The RCIC System is required to be OPERABLE in MODE 1, and MODES 2 and 3 with reactor steam dome pressure > 150 psig since RCIC is the primary non-ECCS water source for core cooling when the reactor is isolated and pressurized. In MODES 2 and 3 with reactor steam dome pressure ≤ 150 psig, and in MODES 4 and 5, RCIC is not required to be OPERABLE since the ECCS injection/spray subsystems can provide sufficient flow to the vessel.
ACTIONS	A Note prohibits the application of LCO 3.0.4.b to an inoperable RCIC system. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable RCIC system and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.3.5

The RCIC System is required to actuate automatically to perform its design function. This Surveillance verifies that with a required system initiation signal (actual or simulated) the automatic initiation logic of RCIC will cause the system to operate as designed, including actuation of the system throughout its emergency operating sequence, automatic pump startup and actuation of all automatic valves to their required positions. This Surveillance test also ensures that the RCIC System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip and that the suction is automatically transferred from the RCIC storage tank to the suppression pool. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.2, "Reactor Core Isolation Cooling (RCIC) System Instrumentation," overlaps this Surveillance to provide complete testing of the assumed safety function.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes vessel injection during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the Surveillance.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 33.
2. USAR, Section 5.4.6.
3. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCO's for ECCS Components," December 1, 1975.
4. Deleted.
5. Calculation 01RI15.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.1 Primary Containment

BASES

BACKGROUND

The function of the primary containment is to isolate and contain fission products released from the Reactor Primary System following a Design Basis Accident (DBA) and to confine the postulated release of radioactive material to within limits. The primary containment consists of a steel lined, reinforced concrete vessel, which surrounds the Reactor Primary System and provides an essentially leak tight barrier against an uncontrolled release of radioactive material to the environment. Additionally, this structure provides shielding from the fission products that may be present in the primary containment atmosphere following accident conditions.

The isolation devices for the penetrations in the primary containment boundary are a part of the primary containment leak tight barrier. To maintain this leak tight barrier:

a. All penetrations required to be closed during accident conditions are either:

   1. capable of being closed by an OPERABLE automatic containment isolation system, or

   2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)";

b. Primary containment air locks are OPERABLE, except as provided in LCO 3.6.1.2, "Primary Containment Air Locks";

c. All equipment hatches are closed;

d. The suppression pool is OPERABLE, except as provided in LCO 3.6.2.2, "Suppression Pool Water Level"; and

(continued)

BASES

BACKGROUND (continued)	e. The primary containment leakage rates are within the limits of this LCO. This Specification ensures that the performance of the primary containment, in the event of a DBA, meets the assumptions used in the safety analyses of References 1 and 2. SR 3.6.1.1.1 leakage rate requirements are in conformance with 10 CFR 50, Appendix J, Option B (Ref. 3), as modified by approved exemptions.
APPLICABLE SAFETY ANALYSES	The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate. The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage. Analytical methods and assumptions involving the primary containment are presented in References 1 and 2. The safety analyses assume a nonmechanistic fission product release following a DBA, which forms the basis for determination of offsite doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded. The maximum allowable leakage rate for the primary containment (L_a) is 0.65% by weight of the containment and drywell air per 24 hours at the design basis LOCA maximum peak containment pressure (P_a) of 9.0 psig (Ref. 4). Primary containment satisfies Criterion 3 of the NRC Policy Statement.
LCO	Primary containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$, except prior to the first startup after performing a required Primary Containment Leakage Rate Testing Program leakage test. At this time, applicable leakage limits must be met. Compliance with this LCO will

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.8 (continued)

leakage through the isolation device. If both isolation valves in the penetration are closed, the actual leakage rate is the lesser leakage rate of the two valves. This method of quantifying maximum pathway leakage is only to be used for this SR.

The Frequency is consistent with the Primary Containment Leakage Rate Testing Program. This SR simply imposes additional acceptance criteria. Secondary containment bypass leakage is considered part of L_a.

Note 1 states that primary containment purge penetrations 1MC-101 and 1MC-102 are excluded from this SR verifying the secondary containment bypass leakage. The leakage through these penetrations is measured by SR 3.6.1.3.5 and the consequences associated with this leakage are evaluated separately as part of the LOCA analysis. Therefore, the leakage through the primary containment purge penetrations is excluded from the total secondary containment bypass leakage as verified in this SR. A second Note is provided to this SR which states that these valves are only required to meet this leakage limit in MODES 1, 2 and 3. In the other conditions, the Reactor Coolant System is not pressurized and specific primary containment leakage limits are not required.

With regard to leakage rate values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Ref. 9).

SR 3.6.1.3.9

The analyses in References 1, 2, and 3 are based on leakage that is less than the specified leakage rate. Combined leakage through all four main steamlines must be ≤ 200 scfh when tested at P_a (9.0 psig). In addition, the leakage rate through any single main steam line must be ≤ 100 scfh when tested at P_a. The MSIV leakage rate must be verified to be in accordance with the assumptions of References 1, 2, and 3. A Note is added to this SR which states that these valves are only required to meet this leakage limit in MODES 1, 2, and 3. In the other conditions, the Reactor Coolant System is not pressurized and primary containment leakage limits are not required. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

(continued)

ACTIONS

A.1 (continued)

containment during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring secondary containment OPERABILITY) occurring during periods where secondary containment is inoperable is minimal.

B.1 and B.2

If the secondary containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

Movement of recently irradiated fuel assemblies in the primary or secondary containment and OPDRVs can be postulated to cause fission product release to the secondary containment. In such cases, the secondary containment is the only barrier to release of fission products to the environment. Movement of recently irradiated fuel assemblies must be immediately suspended if the secondary containment is inoperable.

Suspension of these activities shall not preclude completing an action that involves moving a component to a safe position. Also, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action C.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving recently irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.1.4 and SR 3.6.4.1.5

The SGT System exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. Each SGT subsystem is designed to draw down pressure in the secondary containment to ≥ 0.25 inches vacuum water gauge within the time required and maintain pressure in the secondary containment at ≥ 0.25 inches of vacuum water gauge for 1 hour at a flow rate of ≤ 4400 cfm. To ensure that all fission products released to the secondary containment are treated, SR 3.6.4.1.4 and SR 3.6.4.1.5 verify that a pressure in the secondary containment that is less than the lowest postulated pressure external to the secondary containment boundary can rapidly be established and maintained. When the SGT System is operating as designed, the establishment and maintenance of secondary containment pressure cannot be accomplished if the secondary containment boundary is not intact. Establishment of this pressure is confirmed by SR 3.6.4.1.4, which demonstrates that secondary containment can be drawn down to ≥ 0.25 inches of vacuum water gauge in the required time using one SGT subsystem.

Specifically, the required drawdown time limit is based on ensuring that the SGT system will draw down the secondary containment pressure to ≥ 0.25 inches of vacuum water gauge within 12 minutes (i.e., 10 minutes from start of gap release which occurs 2 minutes after LOCA initiation) under LOCA conditions. Typically, however, the conditions under which drawdown testing is performed pursuant to SR 3.6.4.1.4 are different than those assumed for LOCA conditions. For this reason, and because test results are dependent on or influenced by certain plant and/or atmospheric conditions that may be in effect at the time testing is performed, it is necessary to adjust the test acceptance criteria (i.e., the required drawdown time) to account for such test conditions. Conditions or factors that may impact the test results include wind speed, whether the turbine building ventilation system is running, and whether the containment equipment hatch is open (when the test is performed during plant shutdown/outage conditions). The acceptance criteria for the drawdown test are thus based on a computer model (Ref. 6), verified by actual performance of drawdown tests, in which the drawdown time determined for accident conditions is adjusted to account for performance of the test during normal but certain plant conditions. The test acceptance criteria are specified in the applicable plant test procedure(s). Since the drawdown time is dependent upon secondary containment integrity, the drawdown requirement cannot be met if the secondary containment boundary is not intact.

SR 3.6.4.1.5 demonstrates that the pressure in the secondary containment can be maintained ≥ 0.25 inches of vacuum water gauge for 1 hour using one SGT subsystem at a flow rate of ≤ 4400 cfm. The 1 hour test period allows secondary containment to be in thermal equilibrium at steady state

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.4 and SR 3.6.4.1.5 (continued)

conditions. The primary purpose of these SRs is to ensure secondary containment boundary integrity. The secondary purpose of these SRs is to ensure that the SGT subsystem being tested functions as designed. There is a separate LCO with Surveillance Requirements which serves the primary purpose for ensuring OPERABILITY of the SGT System. These SRs need not be performed with each SGT subsystem. The SGT subsystem used for these Surveillances is staggered to ensure that in addition to the requirements of LCO 3.6.4.3, either SGT subsystem will perform this test. The inoperability of the SGT System does not necessarily constitute a failure of these Surveillances relative to the secondary containment OPERABILITY. Operating experience has shown these components usually pass the Surveillance. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

With regard to drawdown time values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is considered to be a nominal value and therefore does not require compensation for instrument indication uncertainties (Refs. 4, 5).

REFERENCES

1. USAR, Section 15.6.5.
2. USAR, Section 15.7.4.
3. Calculation IP-0-0082.
4. Calculation IP-0-0083.
5. Calculation IP-0-0084.
6. Calculation 3C10-1079-001.

B 3.7 PLANT SYSTEMS

B 3.7.6 Main Turbine Bypass System

BASES

BACKGROUND	The Main Turbine Bypass System is designed to control steam pressure when reactor steam generation exceeds turbine requirements during unit startup, sudden load reduction, and cooldown. It allows excess steam flow from the reactor to the condenser without going through the turbine. The bypass capacity of the system is 28.8% of the Nuclear Steam Supply System rated steam flow. Sudden load reductions within the capacity of the steam bypass can be accommodated without reactor scram. The Main Turbine Bypass System consists of two valve chests (each with three bypass valves) connected to the main steam lines between the main steam isolation valves and the turbine stop valves. Each of the bypass valves is sequentially operated by hydraulic cylinders. The bypass valves are controlled by the pressure regulation function of the Turbine Electro Hydraulic Control System, as discussed in the USAR, Section 7.7.1.5 (Ref. 1). The bypass valves are normally closed, and the pressure regulator controls the turbine control valves, directing all steam flow to the turbine. If the speed governor or the load limiter restricts steam flow to the turbine, the pressure regulator controls the system pressure by opening the bypass valves. When the bypass valves open, the steam flows from the bypass chests, through connecting piping, to the main condenser.
APPLICABLE SAFETY ANALYSES	The Main Turbine Bypass System is assumed to function during the design basis feedwater controller failure, maximum demand event, described in the USAR, Section 15.1.2 (Ref. 2). Opening the bypass valves during the pressurization event mitigates the increase in reactor vessel pressure, which affects the MCPR during the event. The Main Turbine Bypass System satisfies Criterion 3 of the NRC Policy Statement.
LCO	The Main Turbine Bypass System is required to be OPERABLE to limit peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during events that cause rapid pressurization, such that the Safety Limit MCPR is not exceeded.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

tests listed in the Diesel Fuel Oil Testing Program of Specification 5.5.9 are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-95 (Ref. 6);

b. Verify in accordance with the tests specified in ASTM D1298-99 (Ref. 6) that the sample has an API gravity at 60°F of ≥ 30° and ≤ 38°, and in accordance with the tests specified in ASTM D975-06b (Ref. 6) that the sample has a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes; and

c. Verify that the new fuel oil has clear and bright appearance with proper color when tested in accordance with ASTM D4176-93 (Ref. 6), or a water and sediment content ≤ 0.05 v/o when tested in accordance with ASTM-D975-06b.

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO since the fuel oil is not added to the storage tanks.

Following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-06b (Ref. 6) are met for new fuel oil when tested in accordance with ASTM D975-06b (Ref. 6). These additional analyses are required by Specification 5.5.9, Diesel Fuel Oil Testing Program, to be performed within 31 days following sampling and addition. This 31 days is intended to assure: 1) that the sample taken is not more than 31 days old at the time of adding the fuel oil to the storage tank, and 2) that the results of a new fuel oil sample (sample obtained prior to addition but not more than 31 days prior to) are obtained within 31 days after addition. The 31 day period is acceptable because the fuel oil properties of interest, even if not within stated limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.6

Draining of the fuel oil stored in the supply tanks, removal of accumulated sediment, and tank cleaning are required at 10 year intervals by Regulatory Guide 1.137 (Ref. 2), paragraph 2.f. This SR is typically performed in conjunction with the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 7), examinations of the tanks. To preclude the introduction of surfactants in the fuel oil system, the cleaning should be accomplished using sodium hypochlorite solutions, or their equivalent, rather than soap or detergents. This SR is for preventive maintenance. The presence of sediment does not necessarily represent a failure of this SR provided that accumulated sediment is removed during performance of the Surveillance.

REFERENCES

1. USAR, Section 9.5.4.
2. Regulatory Guide 1.137.
3. ANSI N195, Appendix B, 1976.
4. USAR, Chapter 6.
5. USAR, Chapter 15.
6. ASTM Standards: D4057-95; D1298-99; D975-06b; D4176-93; D2276-88.
7. ASME, Boiler and Pressure Vessel Code, Section XI.
8. Calculation IP-0-0120.
9. Calculation IP-0-0121.
10. Calculation IP-0-0122.
11. Calculation IP-C-0111.

BASES

APPLICABILITY (continued)	Inverter requirements for MODES 4 and 5 are covered in the Bases for LCO 3.8.8, "Inverters—Shutdown."

ACTIONS

With a required inverter inoperable, its associated uninterruptible AC bus is inoperable if not energized. LCO 3.8.9 addresses this action; however, pursuant to LCO 3.0.6, these actions would not be entered even if the uninterruptible AC bus were de-energized. Therefore, the ACTIONS are modified by a Note stating that ACTIONS for LCO 3.8.9 must be entered immediately. This ensures the uninterruptible bus is re-energized within 8 hours.

A.1

Required Action A.1 allows 7 days to fix the inoperable inverter and return it to service. The 7 day limit is a risk-informed Completion Time based on a plant-specific risk analysis performed to establish this Completion Time for the Division 1 and 2 inverters. This risk has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems that such a shutdown might entail. When the uninterruptible AC bus is powered from its constant voltage source, it is relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible inverter source to the uninterruptible AC buses is the preferred source for powering instrumentation trip setpoint devices.

With a required inverter inoperable, the following compensatory actions will be taken:

1. Entry into Required Action A.1 will not be planned concurrent with Emergency Diesel Generator (EDG) maintenance on the associated train.
2. Entry into Required Action A.1 will not be planned concurrent with planned maintenance on another RPS or ECCS/RCIC actuation logic channel that could result in that channel being in a tripped condition.

These actions are taken because it is recognized that with an inverter inoperable and the instrument bus being powered by the regulating transformer, instrument power for that train is dependent on power from the associated EDG following a loss of offsite power event.

When the Division 1 NSPS inverter is unavailable, the following compensatory actions will be taken.

1. Entry into the extended inverter CT will not be planned concurrent with shutdown service water maintenance.

(continued)

BASES

ACTIONS

A.1 (continued)

2. Entry into the extended inverter CT will not be planned concurrent with Division 3 (HPCS) maintenance including the Division 3 battery or charger.

3. Entry into the extended inverter CT will not be planned concurrent with maintenance unavailability of the Division 1 or 2 DC components (i.e., batteries or chargers).

4. Entry into the extended inverter CT will not be planned concurrent with maintenance unavailability of the Division 1 NSPS regulating transformer.

During Modes 1, 2 and 3, should the Division 1 NSPS inverter be removed from service for more than 24 hours, then, within 24 hours of removal from service the following will be performed.

1. Conduct walkdowns in Fire Zones A-2k, A-3d, A-3f, CB-1f, CB-2, CB-3a, CB-4, R-1i (southwest corner of R-S line), R-1p (southwest corner of R-S line), R-1t, and T-1f (south end of R-S line), confirming that there are no unauthorized combustibles or other unusual fire hazards in these areas.

2. Inspect Main Control Room panel 1H13-P870, confirming that there are no unauthorized combustibles or other unusual fire hazards in the cabinet.

3. Ensure that the fire protection sprinklers are available for Fire Zones CB-2, CB-3a and CB-4.

4. Hot work will not be permitted in the above areas during this extended maintenance period.

To minimize the potential for a plant trip, when either a Division 1 or 2 NSPS inverter is unavailable, the following compensatory action will be taken.

1. Entry into the extended inverter CT will not be planned concurrent with planned maintenance on another RPS channel that could result in that channel being in a tripped condition.

In addition to the above, the following evaluations will be performed as part of the CPS risk management program whenever inverter maintenance is required.

1. Evaluate simultaneous switchyard maintenance and reliability.

(continued)

BASES

ACTIONS

A.1 (continued)

2. Evaluate concurrent maintenance or inoperable status of any of the remaining three instrument bus inverters for the unit.

3. Evaluate simultaneous EDG maintenance.

B.1

With one or more Division 3 or 4 inverters inoperable, the associated Division 3 ECCS subsystem may be incapable of performing intended function and must be immediately declared inoperable. This also requires entry into applicable Conditions and Required Actions for LCO 3.5.1, "ECCS—Operating."

C.1.1, C.1.2, and C.2

With one RPS solenoid bus inverter inoperable it may be incapable of providing voltage and frequency regulated power

(continued)