ATTACHMENT A

NIAGARA MOHAWK POWER CORPORATION
LICENSE NO. NPF-69
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PROPOSED CHANGES TO TECHNICAL SPECIFICATIONS

Replace existing pages with the attached revised and additional pages. These pages have been retyped in their entirety with marginal markings to indicate changes to text.

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3/4.3 INSTRUMENTATION

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

LIMITING CONDITIONS FOR OPERATION

3.3.1 As a minimum, the reactor protection system instrumentation channels shown in Table 3.3.1-1 shall be OPERABLE with the REACTOR PROTECTION SYSTEM RESPONSE TIME as shown in Table 3.3.1-2.

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

a. With one channel required by Table 3.3.1-1 inoperable in one or more Functional Units, place the inoperable channel and/or that trip system in the tripped condition* within 12 hours. The provisions of Specification 3.0.4 are not applicable.

b. With two or more channels required by Table 3.3.1-1 inoperable in one or more Functional Units:

   1. Within one hour, verify sufficient channels remain OPERABLE or tripped* to maintain trip capability in the Functional Unit, and

   2. Within 6 hours, place the inoperable channel(s) in one trip system and/or that trip system** in the tripped condition*, and

   3. Within 12 hours, restore the inoperable channels in the other trip system to an OPERABLE status or tripped*.

   Otherwise, take the ACTION required by Table 3.3.1-1 for the Functional Unit.

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* An inoperable channel or trip system need not be placed in the tripped condition where this would cause the Trip Function to occur. In these cases, if the inoperable channel is not restored to OPERABLE status within the required time, the ACTION required by Table 3.3.1-1 for the Functional Unit shall be taken.

** This ACTION applies to that trip system with the most inoperable channels; if both trip systems have the same number of inoperable channels, the ACTION can be applied to either trip system.

SURVEILLANCE REQUIREMENTS

4.3.1.1 Each reactor protection system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.1.1-1.

4.3.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months.

4.3.1.3 The REACTOR PROTECTION SYSTEM RESPONSE TIME of each reactor trip functional unit shown in Table 3.3.1-2 shall be demonstrated to be within its limit at least once per 18 months. Each test shall include at least one channel per Trip System so that all channels are tested at least once per N times 18 months, where N is the total number of redundant channels in a specific reactor Trip System.

TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

TABLE NOTATIONS

(a) A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the Trip System in the tripped condition provided at least one OPERABLE channel in the same Trip System is monitoring that parameter.

(b) Unless adequate shutdown margin has been demonstrated per Specification 3.1.1, and the Refuel position one-rod-out interlock is OPERABLE per Specification 3.9.1, the shorting links shall be removed from the RPS circuitry prior to and during the time any control rod is withdrawn.*

(c) An APRM channel is inoperable if there are less than 2 LPRM inputs per level or less than 14 LPRM inputs to an APRM channel.

(d) This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.

(e) This function shall be automatically bypassed when the reactor mode switch is not in the Run position.

(f) This function is not required to be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is not required.

(g) Also actuates the standby gas treatment system.

(h) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

(i) This function shall be automatically bypassed when turbine first stage pressure is less than or equal to 129.6** psig, equivalent to THERMAL POWER less than 30% of RATED THERMAL POWER.

(j) Also actuates the EOC-RPT system.

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* Not required for control rods removed per Specification 3.9.10.1 or 3.9.10.2.

** To allow for instrument accuracy, calibration and drift, a setpoint of less than or equal to 119 psig turbine first stage pressure shall be used.

TABLE 4.3.1.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Intermediate Range Monitors:				
a. Neutron Flux - High	S/U, S,(b) S	S/U(c), W, R(d) W	R R	2 3, 4, 5
b. Inoperative	NA	W	NA	2, 3, 4, 5
2. Average Power Range Monitor(e):				
a. Neutron Flux - Upscale, Setdown	S/U, S,(b) S	S/U(c), W W	SA SA	2 3, 4, 5
b. Flow-Biased Simulated Thermal Power - Upscale	S, D(f)	S/U(c), Q	W(g)(h), SA, R(i)	1
c. Fixed Neutron Flux - Upscale	S	S/U(c), Q	W(g), SA	1
d. Inoperative	NA	Q	NA	1, 2, 3, 4, 5
3. Reactor Vessel Steam Dome Pressure - High	S	Q	R(k)	1, 2
4. Reactor Vessel Water Level - Low, Level 3	S	Q	R(k)	1, 2
5. Main Steam Line Isolation Valve - Closure	NA	Q	R	1
6. Main Steam Line Radiation - High	S	Q	R	1, 2(j)
7. Drywell Pressure - High	S	Q	R(k)	1, 2(l)

TABLE 4.3.1.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEIL- LANCE REQUIRED
8. Scram Discharge Volume Water Level - High				
a. Transmitter/Trip Unit	S	Q	R(k)	1, 2, 5(m)
b. Float Switches	NA	Q	R	1, 2, 5(m)
9. Turbine Stop Valve - Closure	NA	Q	R	1
10. Turbine Control Valve Fast Closure, Valve Trip System Oil Pressure - Low	NA	Q	R	1
11. Reactor Mode Switch Shutdown Position	NA	R	NA	1, 2, 3, 4, 5
12. Manual Scram	NA	W	NA	1, 2, 3, 4, 5

TABLE 4.3.1.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

TABLE NOTATIONS

(a) Neutron detectors may be excluded from CHANNEL CALIBRATION.

(b) The IRM and SRM channels shall be determined to overlap for at least 1/2 decade during each startup after entering OPERATIONAL CONDITION 2, and the IRM and APRM channels shall be determined to overlap for at least 1/2 decade during each controlled shutdown, if not performed within the previous 7 days.

(c) Within 24 hours before startup, if not performed within the previous 7 days.

(d) Perform a CHANNEL FUNCTIONAL TEST with the mode switch in Startup/Hot Standby and the plant in the COLD SHUTDOWN or REFUEL Condition.

(e) The LPRMs shall be calibrated at least once per 1000 effective full-power hours (EFPH) using the TIP system.

(f) Verify measured core flow (total core flow) to be in the range of established core flow at the existing loop flow (APRM%).

(g) This calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER $\geq$25% of RATED THERMAL POWER. Adjust the APRM channel if the absolute difference is greater than 2% of RATED THERMAL POWER. Any APRM channel gain adjustment made in compliance with Specification 3.2.2 shall not be included in determining the absolute difference.

(h) This calibration shall consist of the adjustment of the APRM flow-biased channel to conform to a calibrated flow signal.

(i) This calibration shall consist of verifying the 6 $\pm$ 0.6 seconds simulated thermal power time constant.

(j) This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.

(k) Perform the calibration procedure for the trip unit setpoint at least once per 92 days.

(l) This function is not required to be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is not required to be OPERABLE per Special Test Exception 3.10.1.

(m) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

LIMITING CONDITIONS FOR OPERATION

3.3.2 The isolation actuation instrumentation channels shown in Table 3.3.2-1 shall be OPERABLE with their Trip Setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.2-2 and with ISOLATION SYSTEM RESPONSE TIME shown in Table 3.3.2-3.

APPLICABILITY: As shown in Table 3.3.2-1.

ACTION:

a. With an isolation actuation instrumentation channel Trip Setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.2-2, declare the channel inoperable until the channel is restored to OPERABLE status with its Trip Setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system, either

   1. Place the inoperable channel(s) in the tripped condition within

      a) 12 hours for trip functions common to RPS Instrumentation, and
      b) 24 hours for trip functions not common to RPS Instrumentation

   or
   2. Take the ACTION required by Table 3.3.2-1.

c. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for both trip systems,

   1. Place the inoperable channel(s) in one trip system in the tripped condition within one hour, and

   2. a) Place the inoperable channel(s) in the remaining trip system in the tripped condition within

         1) 12 hours for trip functions common to RPS Instrumentation, and
         2) 24 hours for trip functions not common to RPS Instrumentation,

      or
      b) Take the ACTION required by Table 3.3.2-1.

   The provisions of Specification 3.0.4 are not applicable.

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

TABLE NOTATIONS

* During CORE ALTERATIONS and operations with a potential for draining the reactor vessel. This applies to functions described in notes (c) and (d) that isolate secondary containment and automatically start the SGTS.

** When any turbine stop valve is greater than 90% open and/or when the key-locked condenser low vacuum bypass switch is open (in Normal position).

† Valves 2WCS*MOV102 and 2WCS*MOV112 are also required to be OPERABLE or closed in OPERATIONAL CONDITION 5 with any control rod withdrawn but not with control rods removed per Specifications 3.9.10.1 and 3.9.10.2.

†† When handling irradiated fuel in the reactor building and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

(a) Refer to Table 3.3.2-4 for valve groups, associated isolation signals and key to isolation signals.

(b) A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the Trip System in the tripped condition provided at least one other OPERABLE channel in the same Trip System is monitoring that parameter.

(c) Also actuates the standby gas treatment system.

(d) Also actuates reactor building ventilation isolation dampers per Table 3.6.5.2-1.

(e) Also trips and isolates the air removal pumps.

(f) Initiation of SLCS pump 2SLS*P1B closes 2WCS*MOV102 and manual initiation of SLCS pump 2SLS*P1A closes 2WCS*MOV112.

(g) For this signal one Trip System has 2 channels which close valves 2ICS*MOV 128 and 2ICS*MOV 170, while the other Trip System has 2 channels which close 2ICS*MOV 121.

(h) Manual initiation only isolates 2ICS*MOV121 and only following manual or automatic initiation of the RCIC system.

(i) Only used in conjunction with low RCIC steam supply pressure and high drywell pressure to isolate 2ICS*MOV148 and 2ICS*MOV164.

(j) Signal from LPCS/RHR initiation circuitry.

TABLE 4.3.2.1-1

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTION TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE IS REQUIRED
1. Primary Containment Isolation Signals				
a. Reactor Vessel Water Level				
1) Low, Low, Low, Level 1	S	Q	R(a)	1, 2, 3
2) Low, Low, Level 2	S	Q	R(a)	1, 2, 3 and *
3) Low, Level 3	S	Q	R(a)	1, 2, 3
b. Drywell Pressure - High	S	Q	R(a)	1, 2, 3
c. Main Steam Line				
1) Radiation - High	S	Q	R	1, 2, 3
2) Pressure - Low	S	Q	R(a)	1
3) Flow - High	S	Q	R(a)	1, 2, 3
d. Main Steam Line Tunnel				
1) Temperature - High	S	Q	R(b)	1, 2, 3
2) ΔTemperature - High	S	Q	R(b)	1, 2, 3
3) Temperature - High MSL Lead Enclosure	S	Q	R(b)	1, 2, 3
e. Condenser Vacuum - Low	S	Q	R(a)	1, 2**, 3**
f. RHR Equipment Area Temperature - High (HXs/A&B Pump Rooms)	S	Q	R(b)	1, 2, 3
g. Reactor Vessel Pressure High (RHR Cut-in Permissive)	S	Q	R(a)	1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTION TEST	CHANNEL CALIBRATION	OPERATION CONDITIONS FOR WHICH SURVEILLANCE IS REQUIRED
1. Primary Containment Isolation Signals (Continued)				
h. SGTS Exhaust - High Radiation	NA	Q	R	1, 2, 3
i. RWCU System				
1) ΔFlow - High	S	Q	R	1, 2, 3
2) ΔFlow - High, Timer	NA	Q	R	1, 2, 3
3) Standby Liquid Control, SLCS, Initiation	NA	R	NA	1, 2, 5††
j. RWCU Equipment Area				
1) Pump Room A Temperature - High	S	Q	R(b)	1, 2, 3
2) Pump Room B Temperature - High	S	Q	R(b)	1, 2, 3
3) HX Room Temperature - High	S	Q	R(b)	1, 2, 3
k. Reactor Building Pipe Chase				
1) Azimuth 180° (Upper), Temperature - High	S	Q	R(b)	1, 2, 3
2) Azimuth 180° (Lower), Temperature - High	S	Q	R(b)	1, 2, 3
3) Azimuth 40°, Temperature - High	S	Q	R(b)	1, 2, 3
l. Reactor Building Temperature - High	S	Q	R(b)	1, 2, 3
m. Manual Isolation Pushbutton [NSSSS]	NA	Q(c)	NA	1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTION TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE IS REQUIRED
2. RCIC Isolation Signals				
a. RCIC Steam Line Flow - High, Timer	NA	Q	R	1, 2, 3
b. RCIC Steam Supply Pressure - Low	S	Q	R(a)	1, 2, 3
c. RCIC Steam Line Flow - High	S	Q	R(a)	1, 2, 3
d. RCIC Turbine Exhaust Diaphragm Pressure - High	S	Q	R(a)	1, 2, 3
e. RCIC Equipment Area Temperature - High	S	Q	R(b)	1, 2, 3
f. RCIC Steam Line Tunnel Temperature - High	S	Q	R(b)	1, 2, 3
g. Manual Isolation Pushbutton (RCIC)	NA	Q(c)	NA	1, 2, 3
h. Drywell Pressure - High	S	Q	R(a)	1, 2, 3
i. RHR/RCIC Steam Flow - High	S	Q	R(a)	1, 2, 3
3. Secondary Containment Isolation Signals				
a. Reactor Building Above the Refuel Floor Exhaust Radiation - High	NA	Q	R	1, 2, 3, and †
b. Reactor Building Below the Refuel Floor Exhaust Radiation - High	NA	Q	R	1, 2, 3, and †

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATIONS

* During CORE ALTERATIONS and operations with a potential for draining the reactor vessel. This only applies to secondary containment isolation and automatic start of SGTS.

** When any turbine stop valve is greater than 90% open and/or when the key-locked condenser low vacuum bypass switch is open (in Normal position).

† When handling irradiated fuel in the reactor building and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

†† Valves 2WCS*MOV102 and 2WCS*MOV112 are required to be OPERABLE or closed in OPERATIONAL CONDITION 5 with any control rod withdrawn but not with control rods removed per Specifications 3.9.10.1 and 3.9.10.2.

(a) Perform the calibration procedure for the trip unit setpoint at least once per 92 days.

(b) Calibration excludes sensors; sensor response and comparison shall be done in lieu of.

(c) Manual isolation pushbuttons are tested at least once per operating cycle during shutdown. All other circuitry associated with manual isolation shall receive a CHANNEL FUNCTIONAL TEST at least once per 92 days as part of the circuitry required to be tested for the automatic system isolation.

TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TABLE NOTATIONS

* When the system is required to be OPERABLE per Specification 3.5.2 or 3.5.3.

** Required when ESF equipment is required to be OPERABLE.

(a) A channel may be placed in an inoperable status for up to 6 hours during periods of required surveillance without placing the Trip System in the tripped condition provided at least one other OPERABLE channel in the same Trip System is monitoring that parameter.

(b) Also actuates the associated division diesel generator.

(c) Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

(d) The injection function of Drywell Pressure High and Manual Initiation is not required to be OPERABLE with indicated reactor vessel water level on the wide range instrument greater than level 8 setpoint coincident with the vessel pressure less than 600 psig because of hot calibration/cold operation level error.

(e) Provides signal to close HPCS pump injection valve only.

(f) Provides signal to HPCS pump suction valves only.

ACTION

ACTION 30 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement:

a. With one channel inoperable, place the inoperable channel in the tripped condition within 24 hours* or declare the associated system inoperable.

b. With more than one channel inoperable, declare the associated system inoperable.

ACTION 31 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place the inoperable channel in the tripped condition within 24 hours; restore the inoperable channel to OPERABLE status within 7 days or declare the associated system inoperable.

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* The provisions of Specification 3.0.4 are not applicable.

TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

ACTION

ACTION 32 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, within 24 hours declare the associated ADS Trip System or ECCS inoperable.

ACTION 33 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place the inoperable channel in the tripped condition within 24 hours.

ACTION 34 - Not used.

ACTION 35 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, restore the inoperable channel to OPERABLE status within 24 hours or declare the associated ADS valve or ECCS inoperable.

ACTION 36 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement:

a. For one Trip System, place that Trip System in the tripped condition within 24 hours* or declare the HPCS system inoperable.

b. For both Trip Systems, declare the HPCS system inoperable.

ACTION 37 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place at least one inoperable channel in the tripped condition within 24 hours* or declare the HPCS system inoperable.

ACTION 38 - With the number of OPERABLE channels less than the Total Number of Channels, declare the associated emergency diesel generator inoperable and take the ACTION required by Specification 3.8.1.1 or 3.8.1.2, as appropriate.

ACTION 39 - With the number of OPERABLE channels one less than the Total Number of Channels, place the inoperable channel in the tripped condition within 1 hour*; operation may then continue until performance of the next required CHANNEL FUNCTIONAL TEST.

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* The provisions of Specification 3.0.4 are not applicable.

TABLE 4.3.3.1-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE IS REQUIRED
A. Division I Trip System				
1. RHR-A (LPCI Mode) and LPCS System				
a. Reactor Vessel Water Level - Low, Low, Low, Level 1	S	Q	R(c)	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	S	Q	R(c)	1, 2, 3
c. LPCS Pump Discharge Flow - Low (Bypass)	S	Q	R(c)	1, 2, 3, 4*, 5*
d. LPCS Injection Valve Permissive	S	Q	R(c)	1, 2, 3, 4*, 5*
e. LPCI Injection Valve Permissive	S	Q	R(c)	1, 2, 3, 4*, 5*
f. LPCI Pump A Start Time Delay Relay Normal Power	NA	Q	R	1, 2, 3, 4*, 5*
g. LPCI Pump A Start Time Delay Relay Emergency Power	NA	Q	R	1, 2, 3, 4*, 5*
h. LPCS Pump Start Time Delay Normal Power	NA	Q	R	1, 2, 3, 4*, 5*
i. LPCS Pump Start Time Delay Emergency Power	NA	Q	R	1, 2, 3, 4*, 5*
J. LPCI Pump A Discharge Flow - Low (Bypass)	S	Q	R(c)	1, 2, 3, 4*, 5*
k. Manual Initiation	NA	Q(a)	NA	1, 2, 3, 4*, 5*
2. Automatic Depressurization System Trip System "A"**				
a. Reactor Vessel Water Level - Low, Low, Low, Level 1	S	Q	R(c)	1, 2, 3
b. ADS Timer	NA	Q	Q	1, 2, 3
c. Reactor Vessel Water Level - Low, Level 3 (Permissive)	S	Q	R(c)	1, 2, 3

TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEIL-LANCE IS REQUIRED
A. Division I Trip System (Continued)				
2. Automatic Depressurization System Trip System "A"** (Continued)				
d. LPCS Pump Discharge Pressure - High (Permissive)	S	Q	R(c)	1, 2, 3
e. LPCI Pump A Discharge Pressure - High (Permissive)	S	Q	R(c)	1, 2, 3
f. Manual Inhibit	NA	Q	NA	1, 2, 3
g. Manual Initiation	NA	Q(a)	NA	1, 2, 3
B. Division II Trip System				
1. RHR-B and C (LPCI Mode)				
a. Reactor Vessel Water Level - Low, Low, Low, Level 1	S	Q	R(c)	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	S	Q	R(c)	1, 2, 3
c. LPCI Injection Valve Permissive	S	Q	R(c)	1, 2, 3, 4*, 5*
d. LPCI Pump B Start Time Delay Relay Normal Power	NA	Q	R	1, 2, 3, 4*, 5*
e. LPCI Pump C Start Time Delay Relay Normal Power	NA	Q	R	1, 2, 3, 4*, 5*
f. LPCI Pump B Start Time Delay Emergency Power	NA	Q	R	1, 2, 3, 4*, 5*
g. LPCI Pump C Start Time Delay Relay Emergency Power	NA	Q	R	1, 2, 3, 4*, 5*
h. LPCI Pump Discharge Flow - Low (Bypass)	S	Q	R(c)	1, 2, 3, 4*, 5*
i. Manual Initiation	NA	Q(a)	NA	1, 2, 3, 4*, 5*

TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE IS REQUIRED
B. Division II Trip System (Continued)				
2. Automatic Depressurization System Trip System "B"** (Continued)				
a. Reactor Vessel Water Level - Low, Low, Low, Level 1	S	Q	R(c)	1, 2, 3
b. ADS Timer	NA	Q	Q	1, 2, 3
c. Reactor Vessel Water Level - Low, Level 3 (Permissive)	S	Q	R(c)	1, 2, 3
d. LPCI Pump (B and C) Discharge Pressure - High (Permissive)	S	Q	R(c)	1, 2, 3
e. Manual Inhibit	NA	Q	NA	1, 2, 3
f. Manual Initiation	NA	Q(a)	NA	1, 2, 3
C. Division III Trip System				
1. HPCS System				
a. Reactor Vessel Water Level - Low, Low, Level 2	S	Q	R(c)	1, 2, 3, 4*, 5*
b. Drywell Pressure - High(b)	S	Q	R(c)	1, 2, 3
c. Reactor Vessel Water Level - High, Level 8	S	Q	R(c)	1, 2, 3, 4*, 5*
d. Pump Suction Pressure - Low (Transfer)	S	Q	R(c)	1, 2, 3, 4*, 5*
e. Suppression Pool Water Level - High	S	Q	R(c)	1, 2, 3, 4*, 5*
f. HPCS System Flow Rate - Low (Bypass)	S	Q	R(c)	1, 2, 3, 4*, 5*
g. Pump Discharge Pressure - High (Bypass)	S	Q	R(c)	1, 2, 3, 4*, 5*
h. Manual Initiation(b)	NA	Q(a)	NA	1, 2, 3, 4*, 5*

TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM

ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATIONS

* When the system is required to be OPERABLE per Specification 3.5.2.

** Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

† Required when ESF equipment is required to be OPERABLE.

(a) Manual initiation switches shall be tested at least once per 18 months during shutdown. All other circuitry associated with manual initiation shall receive a CHANNEL FUNCTIONAL TEST at least once per 92 days as part of the circuitry required to be tested for automatic system actuation.

(b) The injection function of Drywell Pressure - High and Manual Initiation is not required to be OPERABLE with indicated reactor vessel water level on the wide range instrument greater than Level 8 setpoint coincident with the vessel pressure less than 600 psig due to the hot calibration/cold operation level error.

(c) Perform the calibration procedure for the Trip Setpoint at least once per 92 days.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITIONS FOR OPERATION

3.3.4.1 The anticipated transient without scram recirculation pump Trip (ATWS-RPT) System instrumentation channels shown in Table 3.3.4.1-1 shall be OPERABLE with their Trip Setpoints set consistent with values shown in the Trip Setpoint column of Table 3.3.4.1-2.

APPLICABILITY: OPERATIONAL CONDITION 1.

ACTION:

a. With an ATWS-RPT system instrumentation channel Trip Setpoint less conservative than the value shown in the Allowable Value column of Table 3.3.4.1-2, declare the channel inoperable until the channel is restored to OPERABLE status with the channel Trip Setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one or both Trip Systems, place the inoperable channel(s) in the tripped condition within 24 hours.

c. With the number of OPERABLE channels two or more less than required by the Minimum Operable Channels per Trip System requirement for one Trip System and:

    1. If the inoperable channels consist of one reactor vessel water level channel and one reactor vessel pressure channel, place both inoperable channels in the tripped condition* within 24 hours.

    2. If the inoperable channels include two reactor vessel water level channels or two reactor vessel pressure channels, declare the Trip System inoperable.

d. With one Trip System inoperable, restore the inoperable Trip System to OPERABLE status within 72 hours or be in at least STARTUP within the next 6 hours.

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* The inoperable channels need not be placed in the tripped condition if this would cause the Trip Function to occur. In this case, the inoperable channel shall be restored to OPERABLE status within 6 hours, or the Trip System shall be declared inoperable.

LIMITING CONDITIONS FOR OPERATION

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

e. With both Trip Systems inoperable, restore at least one Trip System to OPERABLE status within 1 hour or be in at least STARTUP within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.3.4.1.1 Each ATWS-RPT System instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.4.1-1.

4.3.4.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months.

TABLE 3.3.4.1-1

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM*
1. Reactor Vessel Water Level - Low Low, Level 2	2
2. Reactor Vessel Pressure - High	2

* One Trip System may be placed in an inoperable status for up to 6 hours for required surveillance provided the other Trip System is OPERABLE.

TABLE 4.3.4.1-1

ATWS RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. Reactor Vessel Water Level - Low, Low, Level 2	S	Q	R*
2. Reactor Vessel Pressure - High	S	Q	R*

* Perform the calibration procedure for the trip unit setpoint at least once per 92 days.

INSTRUMENTATION

RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITIONS FOR OPERATION

3.3.4.2 The end-of-cycle recirculation pump Trip (EOC-RPT) System instrumentation channels shown in Table 3.3.4.2-1 shall be OPERABLE with their Trip Setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.4.2-2 and with the END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME as shown in Table 3.3.4.2-3.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 30% of RATED THERMAL POWER.

ACTION:

a. With an end-of-cycle recirculation pump Trip System instrumentation channel Trip Setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.4.2-2, declare the channel inoperable until the channel is restored to OPERABLE status with the channel setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one or both Trip Systems, place the inoperable channel(s) in the tripped condition within 12 hours.

c. With the number of OPERABLE channels two or more less than required by the Minimum OPERABLE Channels per Trip System requirement for one Trip System and:

   1. If the inoperable channels consist of one turbine control valve channel and one turbine stop valve channel, place both inoperable channels in the tripped condition within 12 hours.

   2. If the inoperable channels include two turbine control valve channels or two turbine stop valve channels, declare the Trip System inoperable.

d. With one Trip System inoperable, restore the inoperable Trip System to OPERABLE status within 72 hours or take the ACTION required by Specification 3.2.3.

e. With both Trip Systems inoperable, restore at least one Trip System to OPERABLE status within 1 hour or take the ACTION required by Specification 3.2.3.

TABLE 3.3.4.2-1

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM*
1. Turbine Stop Valve - Closure	2**
2. Turbine Control Valve - Fast Closure	2**

* A Trip System may be placed in an inoperable status for up to 6 hours for required surveillance provided that the other Trip System is OPERABLE.

** This function shall be automatically bypassed when turbine first-stage pressure is less than or equal to 129.6 psig, equivalent to THERMAL POWER less than 30% of RATED THERMAL POWER. To allow for instrument accuracy, calibration, and drift, a setpoint of less than or equal to 119 psig shall be used.

TABLE 3.3.4.2-2

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. Turbine Stop Valve - Closure	$\leq$5% closed	$\leq$7% closed
2. Turbine Control Valve - Fast Closure	$\geq$530 psig	$\geq$465 psig

TABLE 3.3.4.2-3

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (MILLISECONDS)
1. Turbine Stop Valve - Closure	$\leq$190
2. Turbine Control Valve - Fast Closure	$\leq$190

TABLE 4.3.4.2-1

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. Turbine Stop Valve - Closure	Q	R
2. Turbine Control Valve - Fast Closure	Q	R

TABLE 3.3.5-1

REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

FUNCTIONAL UNITS		MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM(a)	ACTION
1.	Reactor Vessel Water Level - Low, Low, Level 2	2	50
2.	Reactor Vessel Water Level - High, Level 8(b)	2	50
3.	Pump Suction Pressure - Low (Transfer)	2(c)	51
4.	Manual Initiation(d)	1/system(e)	52

TABLE NOTATIONS

(a) A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the Trip System in the tripped condition provided at least one other OPERABLE channel in the same Trip System is monitoring that parameter.

(b) The RCIC Level 8 trip may be bypassed to perform RCIC 150 psig operational surveillance test in accordance with Specification 4.7.4.c.2.

(c) One Trip System with one-out-of-two logic.

(d) Manual initiation is not required to be OPERABLE with indicated reactor vessel water level on the wide-range instrument greater than the Level 8 setpoint coincident with the vessel pressure less than 600 psig due to the hot calibration/cold operation level error.

(e) One Trip System with one channel.

TABLE 3.3.5-1 (Continued)

REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

ACTION

ACTION 50 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement:

a. For one Trip System, place the inoperable channel(s) and/or that Trip System in the tripped condition within 24 hours or declare the RCIC system inoperable.

b. For both Trip Systems with more than one channel inoperable, declare the RCIC system inoperable.

ACTION 51 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, place at least one inoperable channel in the tripped condition within 24 hours or declare the RCIC system inoperable.

ACTION 52 - With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement, restore the inoperable channel to OPERABLE status within 24 hours or declare the RCIC system inoperable.

TABLE 4.3.5.1-1

REACTOR CORE ISOLATION COOLING SYSTEM

ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. Reactor Vessel Water Level - Low, Low, Level 2	S	Q	R*
2. Reactor Vessel Water Level - High, Level 8	S	Q	R*
3. Pump Suction Pressure - Low (Transfer)	S	Q	R*
4. Manual Initiation **	NA	Q†	NA

* Perform the calibration procedure for the trip unit setpoint at least once per 92 days.

** Manual initiation is not required to be OPERABLE with indicated reactor vessel water level on the wide range instrument greater than Level 8 setpoint coincident with the vessel pressure less than 600 psig because of the hot calibration/cold operation level error.

† Manual initiation switches shall be tested at least once per 18 months during shutdown. All other circuitry associated with manual initiation shall receive a CHANNEL FUNCTIONAL TEST at least once per 92 days as part of circuitry required to be tested for automatic system actuation.

INSTRUMENTATION

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

LIMITING CONDITIONS FOR OPERATION

3.3.6. The control rod block instrumentation channels shown in Table 3.3.6-1 shall be OPERABLE with their Trip Setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.6-2.

Applicability: As shown in Table 3.3.6-1.

ACTION:

a. With a control rod block instrumentation channel Trip Setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.6-2, declare the channel inoperable until the channel is restored to OPERABLE status with its Trip Setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, take the ACTION required by Table 3.3.6-1.

SURVEILLANCE REQUIREMENTS

4.3.6 Each of the above required control rod block Trip Systems and instrumentation channels shall be demonstrated OPERABLE* by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, AND CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.6-1.

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* A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the Trip System in the tripped condition, provided at least one other operable channel in the same Trip System is monitoring that Trip Function.

TABLE 3.3.6-1 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION

TABLE NOTATIONS

*	With THERMAL POWER greater than or equal to 30% of RATED THERMAL POWER.
**	With more than one control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.
(a)	The RBM shall be automatically bypassed when a peripheral control rod is selected.
(b)	This function shall be automatically bypassed if detector count rate is greater than 100 cps or the IRM channels are on range 3 or higher.
(c)	This function shall be automatically bypassed when the associated IRM channels are on range 8 or higher.
(d)	This function shall be automatically bypassed when the IRM channels are on range 3 or higher.
(e)	This function shall be automatically bypassed when the IRM channels are on range 1.
(f)	During complete core spiral offloading and reloading, an SRM downscale rod block instrumentation channel is not required to be OPERABLE when the associated SRM channel is downscale.

ACTION

ACTION 60 - Declare the RBM inoperable and take the ACTION required by Specification 3.1.4.3.

ACTION 61 - With the number of OPERABLE Channels:

a. One less than required by the Minimum OPERABLE Channels per Trip Function requirement, restore the inoperable channel to OPERABLE status within 7 days or place the inoperable channel in the tripped condition within the next hour.

b. Two or more less than required by the Minimum OPERABLE Channels per Trip Function requirement, place at least one inoperable channel in the tripped condition within 1 hour.

ACTION 62 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place the inoperable channel in the tripped condition within 12 hours.

TABLE 4.3.6-1

CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Rod Block Monitor				
a. Upscale	NA	S/U(b)(c), Q(c)	Q	1*
b. Inoperative	NA	S/U(b)(c), Q(c)	NA	1*
c. Downscale	NA	S/U(b)(c), Q(c)	Q	1*
2. APRM				
a. Flow-Biased Neutron Flux Upscale	NA	S/U(b), Q	Q	1
b. Inoperative	NA	S/U(b), Q	NA	1, 2, 5
c. Downscale	NA	S/U(b), Q	Q	1
d. Neutron Flux - Upscale, Startup	NA	S/U(b), Q	Q	2, 5
3. Source Range Monitors				
a. Detector Not Full In	NA	S/U(b), W	NA	2, 5
b. Upscale	NA	S/U(b), W	Q	2, 5
c. Inoperative	NA	S/U(b), W	NA	2, 5
d. Downscale	NA	S/U(b), W	Q	2, 5
4. Intermediate Range Monitors				
a. Detector Not Full In	NA	S/U(b), W	NA	2, 5
b. Upscale	NA	S/U(b), W	Q	2, 5
c. Inoperative	NA	S/U(b), W	NA	2, 5
d. Downscale	NA	S/U(b), W	Q	2, 5

TABLE 4.3.6-1 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
5. Scram Discharge Volume				
Water Level - High, Float Switch	NA	Q	R	1, 2, 5**
6. Reactor Coolant System Recirculation Flow				
a. Upscale	NA	S/U(b), Q	Q	1
b. Inoperative	NA	S/U(b), Q	NA	1
c. Comparator	NA	S/U(b), Q	Q	1
7. Reactor Mode Switch				
a. Shutdown Mode	NA	R	NA	3, 4
b. Refuel Mode	NA	R	NA	5

TABLE 3.3.7.1-1

RADIATION MONITORING INSTRUMENTATION

	INSTRUMENTATION	MINIMUM CHANNELS OPERABLE	APPLICABLE CONDITIONS	ALARM/TRIP SETPOINT (a)	ACTION
1.	Main Control Room Ventilation Radiation Monitors	2/System(b)(e)	1, 2, 3, 5, and *	$\leq 5.92 \times 10^{-6} \mu Ci/cc$(c)	74
2.	Area Monitors				
	a. Criticality Monitor (New Fuel Storage Vault)	1	**	$\leq 1.0 \times 10^{2}$ mR/hr(d)	76
	b. Control Room Direct Radiation Monitor	1	At all times	$\leq 2.5 \times 10^{-1}$ mR/hr(d)	76

TABLE 3.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION

TABLE NOTATIONS

* When handling irradiated fuel in the reactor building and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

** With fuel in the new fuel storage vault.

(a) Above measured background.

(b) Two Trip Systems, one for each special filter train and associated bypass valve, are provided with two channels per Trip System.

(c) Initiates control room emergency filtration with both channels of one Trip System at high setpoint.

(d) Alarm only.

(e) A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the Trip System in the tripped condition, provided at least one other operable channel in the same Trip System is monitoring that Trip Function.

ACTION

ACTION 72 - Deleted.

ACTION 73 - Deleted.

ACTION 74 -

a. With the number of OPERABLE channels in one or both Trip Systems one less than the minimum number of OPERABLE channels required, place the inoperable channel in the tripped condition within 24 hours.

b. With the number of OPERABLE channels in one Trip System two less than the minimum number of OPERABLE channels required, restore at least one of the inoperable channels to OPERABLE status within 7 days, or within the next 6 hours ensure operation of the control room emergency filtration system in the filtration mode of operation.

c. With the number of OPERABLE channels in both Trip Systems two less than the minimum OPERABLE channels required, within 1 hour, ensure operation of the control room emergency filtration system in the filtration mode of operation.

TABLE 3.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION

ACTION

ACTION 75 - Deleted.

ACTION 76 - With the required monitor inoperable, perform area surveys of the monitored area with portable monitoring instrumentation at least once every 24 hours.

TABLE 4.3.7.1-1

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTATION	CHANNEL CHECK	SOURCE CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Main Control Room Ventilation Radiation Monitors	S	NA	Q	R	1, 2, 3, 5, and *
2. Area Monitors					
a. Criticality Monitors (New Fuel Storage Vault)	S	M	SA	R	**
b. Control Room Direct Radiation Monitor	S	M	SA	R	At all times

* When handling irradiated fuel in the reactor building and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

** With fuel in the new fuel storage vault.

TABLE 3.3.9-1

PLANT SYSTEMS ACTUATION INSTRUMENTATION

TRIP FUNCTION	INSTRUMENT NUMBER	MINIMUM OPERABLE CHANNELS (a)	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. Feedwater System/Main Turbine Trip System				
Reactor Vessel Water Level - High, Level 8	2ISC*LSH1624A,B,C	3	1	140
2. Service Water System				
a. Discharge Bay Level	2SWP*LS30A,B	2	1,2,3,4,5	142
b. Intake Tunnel 1 & 2 Water Temperature	2SWP*TSL64A,65A 2SWP*TSL64B,65B	1/Division 1/Division	1,2,3,4,5 1,2,3,4,5	144 144
c. Service Water Bay	2SWP*LS73A,B	2	1,2,3,4,5	143
d. Service Water Pumps Discharge Strainer Differential Pressure - Train "A"	2SWP*PDSH1A,C,E	1/Strainer	1,2,3,4,5	146
e. Service Water Pumps Discharge Strainer Differential Pressure - Train "B"	2SWP*PDSH1B,D,F	1/Strainer	1,2,3,4,5	146
f. Service Water Supply Header Discharge Water Temperature	2SWP*TY31A,B	2	1,2,3,4,5	147
g. Service Water Inlet Pressure for EDG*2 (HPCS, Division III)				
1) Division I Supply Header	2SWP*PSL95A	1	1,2,3,4,5	145
2) Division II Supply Header	2SWP*PSL95B	1	1,2,3,4,5	145

(a) A channel may be placed in an inoperable status for up to 2 hours for required surveillance without placing the Trip System in the tripped condition, except for discharge bay level and service water bay level which may be placed in an inoperable status for up to 4 hours without placing the Trip System in a tripped condition and Reactor Vessel Level-High, Level 8 channel, which may be placed in an inoperable status for up to 6 hours for required surveillance without placing the Trip System in the tripped condition.

TABLE 4.3.9.1-1

PLANT SYSTEMS ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Feedwater System/Main Turbine Trip System				
a. Reactor Vessel Water Level - High Level 8	NA	Q	R	1
2. Service Water System				
a. Discharge Bay Level	NA	R	R	1, 2, 3, 4, 5
b. Intake Tunnel 1 & 2 Water Temperature	W	R	R*	1, 2, 3, 4, 5
c. Service Water Bay	NA	R	R	1, 2, 3, 4, 5
d. Service Water Pumps Discharge Strainer Differential Pressure - Train "A"	S	R	R	1, 2, 3, 4, 5
e. Service Water Pumps Discharge Strainer Differential Pressure - Train "B"	S	R	R	1, 2, 3, 4, 5
f. Service Water Supply Header Discharge Water Temperature	S	R	R	1, 2, 3, 4, 5
g. Service Water Inlet Pressure for EDG*2 (HPCS, Division III)				
1) Division I Supply Header	NA	R	R	1, 2, 3, 4, 5
2) Division II Supply Header	NA	R	R	1, 2, 3, 4, 5

* Calibration excludes sensors; a comparison test of the four RTDs will be done.

SURVEILLANCE REQUIREMENTS

4.4.2.1 The acoustic monitor for each safety/relief valve shall be demonstrated OPERABLE*** with the setpoint verified to be 0.25 of the full-open noise level* by performance of a:

a. CHANNEL FUNCTIONAL TEST at least once per 92 days, and a
b. CHANNEL CALIBRATION at least once per 18 months.**

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* Initial setting shall be in accordance with the manufacturers recommendation. Adjustment to the valve full-open noise level shall be accomplished during the startup test program.

** The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test.

*** A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the Trip System in the tripped condition.

3/4.3 INSTRUMENTATION

BASES

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

The reactor protection system (RPS) automatically initiates a reactor scram to:

a. Preserve the integrity of the fuel cladding.

b. Preserve the integrity of the reactor coolant system.

c. Minimize the energy which must be adsorbed following a loss-of-coolant accident, and

d. Prevent inadvertent criticality.

This specification provides the Limiting Conditions for Operation necessary to preserve the ability of the system to perform its intended function even during periods when instrument channels may be out of service because maintenance is being performed. When necessary, one channel may be made inoperable for brief intervals to conduct required surveillance.

The reactor protection system is made up of two independent trip systems. There are usually four channels to monitor each parameter, and there are two channels in each trip system. The outputs of the channels in a trip system are combined in a logic so that either channel will trip that trip system. The tripping of both trip systems will produce a reactor scram. The system meets the intent of IEEE-279 for nuclear power plant protection systems. Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," and MDE-78-0485, "Technical Specification Improvement Analysis for Nine Mile Point Nuclear Station, Unit 2." The bases for the trip settings of the RPS are discussed in the bases for Specification 2.2.1.

The measurement of response time at the specified frequencies provides assurance that the protective functions associated with each channel are completed within the time limit assumed in the safety analyses. No credit was taken for those channels with response times indicated as not applicable. Response time may be demonstrated by any series of sequential, overlapping or total channel test measurement, provided such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either (1) inplace, onsite, or offsite test measurements, or (2) utilizing replacement sensors with certified response times.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

This specification ensure the effectiveness of the instrumentation used to mitigate the consequences of accidents by prescribing the OPERABILITY trip setpoints and response times for isolation of the reactor systems. When necessary, one channel may be inoperable for brief intervals to conduct required surveillance. Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with NEDC-30851P-A, Supplement 2, "Technical Specification Improvement Analyses for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," and with NEDC-31677P-A, "Technical Specification Improvement Analyses for BWR Isolation Actuation Instrumentation." Some of the trip settings may have tolerances explicitly stated where both the high and low values are critical and may have a substantial effect on safety. The setpoints of other instrumen-tation, where only the high or low end of the setting has a direct bearing on safety, are established at a level away from the normal operating range to prevent inadvertent actuation of the systems involved.

Except for the MSIVs, the FSAR Chapter 15 safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. For AC-operated valves, it is assumed that the AC power supply is lost and is restored by startup of the emergency diesel generators. In this event, a time of 13 seconds is assumed before the valve starts to move. In addition to the pipe break, the failure of the DC-operated valve is assumed; thus the signal delay (sensor response) is concurrent with the 13-second diesel startup. The safety analysis considers an allowable inventory loss in each case which in turn determines the valve speed in conjunction with the 13-second delay. It follows that checking the valve speeds and the 13-second time for establishing emergency power will establish the response time for the isolation functions.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analysis. The Trip Setpoint and Allowable Value also contain additional margin for instrument accuracy and calibration capability.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

The emergency core cooling system actuation instrumentation is provided to initiate actions to mitigate the consequences of accidents that are beyond the ability of the operator to control.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

This specification provides the OPERABILITY requirements, Trip Setpoints, and response times that will ensure effectiveness of the systems to provide the design protection. Although the instruments are listed by system, in some cases the same instrument may be used to send the actuation signal to more than one system at the same time.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analysis. The Trip Setpoint and Allowable Value also contain additional margin for instrument accuracy and calibration capability.

The HPCS pump suction pressure-low represents an analytical transfer level in the condensate storage tank of 14 feet at maximum flow and 3.0 feet at minimum flow. This is above the corresponding minimum tank level of 10.2 feet at maximum flow and 2.9 feet at minimum flow required to prevent vortexing.

Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with NEDC-30936P-A, "Technical Specification Improvement Methodology, (with Demonstration for BWR ECCS Actuation Instrumentation) Parts 1 and 2," and RE-026, "Technical Specification Improvement Analysis for the Emergency Core Cooling System Actuation Instrumentation for Nine Mile Point Nuclear Station, Unit 2."

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses. The Trip Setpoint and Allowable Value also contain additional margin for instrument accuracy and calibration capability. Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-Of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R. D. Binz IV from C. E. Rossi dated July 21, 1992).

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

The reactor core isolation cooling system actuation instrumentation is provided to initiate actions to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses. The Trip Setpoint and Allowable Value also contain additional margin for instrument accuracy and calibration capability. Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with GENE-770-06-2, "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-Of-Service Times for Selected Instrumentation Technical Specifications, (BWR RCIC Instrumentation)," as approved by the NRC and documented in the SER (letter to G. J. Beck from C. E. Rossi dated September 13, 1991).

The RCIC pump suction pressure-low represents an analytical transfer level in the condensate storage tank of 13.1 feet at maximum flow and 2.53 feet at minimum flow. This is above the corresponding minimum tank level of 5.0 feet at maximum flow and 2.5 feet at minimum flow required to prevent vortexing.

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

The control rod block functions are provided consistent with the requirements of the specifications in Section 3/4.1.4, Control Rod Program Controls, and Section 3/4.2, Power Distribution

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION (Continued)

Limits. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses. The Trip Setpoint and Allowable Value also contain additional margin for instrument accuracy and calibration capability. Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with NEDC-30851P-A Suppl. 1 "Technical Specification Improvement Analyses for BWR Control Rod Block Instrumentation," and GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-Of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R. D. Binz IV from C. E. Rossi dated July 21, 1992). The scram discharge volume water level-high setpoint is referenced to a scram discharge volume instrument zero level at elevation 263 feet 10 inches.

3/4.3.7 MONITORING INSTRUMENTATION

3/4.3.7.1 RADIATION MONITORING INSTRUMENTATION

The OPERABILITY of the radiation monitoring instrumentation ensures that: (1) the radiation levels are continually measured in the areas served by the individual channels; (2) the alarm or automatic action is initiated when the radiation level Trip Setpoint is exceeded; and (3) sufficient information is available on selected plant parameters to monitor and assess these variables following an accident. This capability is consistent with 10 CFR 50, Appendix A, General Design Criteria (GDC) 19, 41, 60, 61, 63 and 64. Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-Of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R. D. Binz IV from C. E. Rossi dated July 21, 1992).

TURBINE OVERSPEED PROTECTION SYSTEM (Continued)

will protect the turbine from excessive overspeed. Protection from excessive turbine overspeed is required since excessive overspeed could generate potentially damaging missiles which could impact and damage safety-related components, equipment, or structures.

3/4.3.9 PLANT SYSTEMS ACTUATION INSTRUMENTATION

The plant systems actuation instrumentation is provided: (1) to initiate action of the feedwater system/main turbine trip system in the event of feedwater controller failure and (2) to ensure the proper operation of the service water system during normal and accident conditions. Specified surveillance intervals have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-Of-Service Times for Selected Instrumentation Technical Specification," as approved by the NRC and documented in the SER (letter to R. D. Binz IV from C. E. Rossi dated July 21, 1992).

RECIRCULATION SYSTEM

3/4.4.1 (Continued)

recirculation pump and recirculation nozzles. Sudden equalization of a temperature difference $\geq$ 145°F between the reactor vessel bottom head coolant and the coolant in the upper region of the reactor vessel by increasing core flow rate would cause undue stress in the reactor vessel bottom head.

3/4.4.2 SAFETY/RELIEF VALVES

The safety/relief valves operate during a postulated ATWS event to prevent the reactor coolant system from being pressurized above a design allowable value of 1375 psig in accordance with the ASME Code. A total of 16 OPERABLE safety/relief valves is required to limit local pressure at active components to within ASME III allowable design values (Service Level A). All other appropriate ASME III limits are also bounded by this requirement. Specified surveillance intervals have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-Of-Service Times for Selected Instrumentation Technical Specification," as approved by the NRC and documented in the SER (letter to R. D. Binz IV from C. E. Rossi dated July 21, 1992).

The safety/relief valve lift settings will be demonstrated only during shutdown in accordance with the provisions of Specification 4.0.5.

3/4.4.3 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.3.1 LEAKAGE DETECTION SYSTEMS

The RCS leakage detection systems required by this specification are provided to monitor and detect leakage from the reactor coolant pressure boundary. These detection systems are consistent with the recommendations of RG 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973.

3/4.4.3.2. OPERATIONAL LEAKAGE

The allowable leakage rates from the reactor coolant system have been based on the predicted and experimentally observed behavior of cracks in pipes. The background leakage normally expected to result from equipment design and the detection capability of the instrumentation for determining system leakage were also considered. The evidence obtained from experiments suggests that for leakage somewhat greater than that specified for UNIDENTIFIED LEAKAGE, the probability is small that the imperfection or crack

3/4.4.3.2 OPERATIONAL LEAKAGE (Continued)

associated with such leakage would grow rapidly. However, in all cases, if the leakage rates exceed the values specified or the leakage is located and known to be PRESSURE BOUNDARY LEAKAGE, the reactor will be shut down to allow further investigation and corrective action.

The Surveillance Requirements for RCS pressure isolation valves provide added assurance of valve integrity, thereby reducing the probability of gross valve failure and consequent intersystem LOCA.

ATTACHMENT B

NIAGARA MOHAWK POWER CORPORATION
LICENSE NO. NPF-69
DOCKET NO. 50-410

SUPPORTING INFORMATION AND NO SIGNIFICANT HAZARDS CONSIDERATIONS ANALYSIS

I. INTRODUCTION

The proposed changes reflect those standard Technical Specification (TS) revisions contained in the GE License Topical Reports which, based upon probabilistic analyses, justify the identified time extensions by reducing: i) the potential for unnecessary plant scrams, ii) excessive equipment test cycles, and iii) diversion of personnel and resources on unnecessary testing. The NRC staff has reviewed and approved these Licensing Topical Reports in the letters, and accompanying Safety Evaluation Reports (SERs), from A. C. Thadani (NRC) to T. A. Pickens (BWR Owners' Group) dated July 15, 1987; from Charles E. Rossi (NRC) to D. N. Grace (BWRs Owners' Group) dated January 6, 1989; from Charles E. Rossi (NRC) to S. D. Floyd (BWRs Owners' Group) dated June 18, 1990; from A. C. Thadani (NRC) to D. N. Grace (BWR Owners' Group) dated December 9, 1988; from Charles E. Rossi (NRC) to D. N. Grace (BWRs Owners' Group) dated December 9, 1988; from Charles E. Rossi (NRC) to G. J. Beck (BWRs Owners' Group) dated Sept. 13, 1991; from Charles E. Rossi (NRC) to D. N. Grace (BWRs Owners' Group) dated Sept. 22, 1988 and from Charles E. Rossi (NRC) to R. D. Binz IV (BWRs Owners' Group) dated July 21, 1992.

II. DESCRIPTION OF THE PROPOSED CHANGES

Revise the Reactor Protection System (RPS), Isolation Actuation, ECCS Actuation, RCIC, Control Rod Block and Selected Instrumentation Technical Specification (TS) requirements (TS 3/4.3 and 3/4.4.2 Instrumentation) regarding the surveillance test intervals (STIs) and allowable out-of-service times (AOTs) in accordance with General Electric Company (GE) Licensing Topical Reports (LTRs) NEDC-30851P-A dated March 1988, NEDC-30851P-A (Suppl 2) dated March 1989, NEDC 31677P-A dated July 1990, NEDC-30936P-A (Parts 1 and 2) dated December 1988, GENE-770-06-2 dated February 1991, NEDC 30851P-A (Suppl 1) dated October 1988, and GENE-770-06-1 dated February 1991. Also, AOTs are clarified in accordance with most recently approved BWR Owners' Group letters. In summary, changes requested are the following:

NEDC-30851P-A dated March 1988/MDE-78-0485 dated April 1985

1. Increase and clarify[1] the time permitted to place an inoperable RPS instrumentation channel in the tripped condition when the number of operable channels is less than that required in TS Table 3.3.1-1 from one hour to twelve hours, (T.S. 3.3.1, ACTION a., b. Note *,**).

[1] BWROG-92102 letter from C. L. Tully (BWROG) to B. K. Grimes (NRC), "BWR Owners' Group (BWROG) Topical Reports on Technical Specification Improvement Analysis for BWR Reactor Protection Systems - Use For Relay and Solid State Plants (NEDC-30884 and NEDC-30851P)", dated November 4, 1992.

2. Increase the time permitted for an operable RPS instrumentation channel to be declared inoperable for surveillance purposes without placing the channel in the tripped condition from 2 hours to 6 hours (TS Table 3.3.1-1, TABLE NOTATIONS (a)).

3. Increase the channel functional test interval requirement in TS Table 4.3.1.1-1 from weekly to quarterly for the following FUNCTIONAL UNITS:

   a. Average Power Range Monitor Flow Biased Simulated Thermal Power - Upscale (FUNCTIONAL UNIT 2.b.)
   b. Average Power Range Monitor Fixed Neutron Flux - Upscale (FUNCTIONAL UNIT 2.c.)
   c. Average Power Range Monitor Inoperative (FUNCTIONAL UNIT 2.d.)

4. Increase the channel functional test interval requirement in TS Table 4.3.1.1-1 from monthly to quarterly for the following FUNCTIONAL UNITS:

   a. Reactor Vessel Steam Dome Pressure - High (FUNCTIONAL UNIT 3.)
   b. Reactor Vessel Water Level - Low, Level 3 (FUNCTIONAL UNIT 4.)
   c. Main Steam Line Isolation Valve - Closure (FUNCTIONAL UNIT 5.)
   d. Main Steam Line Radiation - High (FUNCTIONAL UNIT 6.)
   e. Drywell Pressure - High (FUNCTIONAL UNIT 7.)
   f. Scram Discharge Volume Water Level - High, Transmitter Trip Unit (FUNCTIONAL UNIT 8.a.)
   g. Scram Discharge Volume Water Level - High, Float Switches (FUNCTIONAL UNIT 8.b.)
   h. Turbine Stop Valve - Closure (FUNCTIONAL UNIT 9.)
   i. Turbine Control Valve Fast Closure, Valve Trip System Oil Pressure - Low (FUNCTIONAL UNIT 10.).

5. Decrease the channel functional test interval requirement in TS Table 4.3.1.1-1 for Manual Scram from monthly to weekly (FUNCTIONAL UNIT 12.).

6. Revise Table 4.3.1.1-1 TABLE NOTATION (k) from 31 days to 92 days.

7. Modify the TS Bases Section 3/4.3.1 to reference the NEDC Report on Technical Specification Improvement (TSI) Analysis for BWR RPS (NEDC-30851P-A) and Plant-Specific Report (MDE-78-0485) which justifies the above proposed changes.

NEDC-30851P-A (Suppl 2) dated March 1989/NEDC-31677P-A dated July 1990

8. Increase and clarify[(2)] the time permitted to place an inoperable channel in the tripped condition when the number of operable channels is less than that required in TS Table 3.3.2-1 from 1 hour to 12 hours for trip functions common to RPS instrumentation and 24 hours from trip functions not common to RPS Instrumentation (TS 3.3.2 ACTION b., c.).

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(2) 0G90-579-32A, letter to Millard L. Wohl, NRC, from W. P. Sullivan and J. F. Klapproth, GE, "Implementation Enhancements To Technical Specification Changes Given In Isolation Actuation Instrumentation Analysis," June 25, 1990.

9. Revise Table 3.3.2-1 TABLE NOTATION (b) from 2 hours to 6 hours.

10. Increase the channel functional test interval requirement in TS Table 4.3.2.1-1 from monthly to quarterly for the following TRIP FUNCTIONS.

    a. Primary Containment Isolation Signals. (TRIP FUNCTION 1)
    b. RCIC Isolation Signals. (TRIP FUNCTION 2)
    c. Secondary Containment Isolation Signals. (TRIP FUNCTION 3)

11. Revise Table 4.3.2.1-1 TABLE NOTATIONS (a)(c) from 31 days to 92 days.

12. Modify the TS Bases Section 3/4.3.2 to reference NEDC Report on TSI analysis (NEDC - 30851P-A Suppl 2, NEDC - 31677P-A) which justifies the above proposed changes.

NEDC - 30936P-A (Parts 1 and 2) dated December 1988/RE-026 dated February 1987

13. Revise Table 3.3.3-1 TABLE NOTATION (a) from 2 hours to 6 hours.

14. Revise and clarify[3] Table 3.3.3-1 ACTIONS 30, 31, 32, 33, 35, 36 and 37 to allow 24 hours to restore an inoperable channel.

15. Increase the channel functional test interval requirement in TS Table 4.3.3.1-1 from monthly to quarterly for the following TRIP FUNCTIONS.

    a. Division I Trip System. (TRIP FUNCTION A.)
    b. Division II Trip System. (TRIP FUNCTION B.)
    c. Division III Trip System. (TRIP FUNCTION C.)

16. Revise Table 4.3.3.1-1 TABLE NOTATIONS (a)(c) from 31 days to 92 days.

17. Modify the TS Bases Section 3/4.3.3 to reference the NEDC report on Technical Specifications Improvement Analysis for BWR ECCS Actuation Instruments (NEDC - 30936P-A) and Plant-Specific Report (RE-026) which justifies the above proposed changes.

GENE-770-06-1 Selected Instruments dated February 1991

18. Revise TS 3.3.4.1 ACTION b. and ACTION c.1. from within 1 hour to within 24 hours.

19. Revise footnote * for ACTION c.1. and Table 3.3.4.1-1 from 2 hours to 6 hours.

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(3) 0G90-319-32D, letter to Millard L. Wohl, NRC, from W. P. Sullivan and J. F. Klapproth, GE, "Clarification of Technical Specification Changes Given in ECCS Actuation Instrumentation Analysis", March 22, 1990.

20. Increase the channel functional test interval requirement in TS Table 4.3.4.1-1 from monthly to quarterly for the following TRIP FUNCTIONS.

    a. Reactor Vessel Level-Low, Low, Level 2 (TRIP FUNCTION 1.)
    b. Reactor Vessel Pressure-High (TRIP FUNCTION 2.)

21. Revise Table 4.3.4.1-1 footnote * from 31 days to 92 days.

22. Revise TS 3.3.4.2 ACTION b. from one hour to 12 hours.

23. Revise TS 3.3.4-2 ACTION c.1. from one hour to 12 hours.

24. Revise Table 3.3.4-2-1 footnote * from 2 hours to 6 hours.

25. Increase the channel functional test interval requirement in TS Table 4.3.4.2-1 from monthly to quarterly for the following TRIP FUNCTIONS.

    a. Turbine Stop Valve - Closure (TRIP FUNCTION 1.)
    b. Turbine Control Valve - Fast Closure (TRIP FUNCTION 2.)

26. Modify the TS Bases Section 3/4.3.4 to reference the GE Topical Report on Bases for changes to surveillance test intervals and allowed out-of-service times for Selected Instruments (GENE-770-06-1) which justifies the above proposed changes.

GENE-770-06-2 RCIC Instruments dated February 1991

27. Revise Table 3.3.5-1 TABLE NOTATION (a) from 2 hours to 6 hours.

28. Revise and clarify[3] Table 3.3.5-1 ACTIONS 50, 51, and 52 to allow 24 hours to restore an inoperable channel.

29. Increase channel functional test interval requirement in TS Table 4.3.5.1-1 from monthly to quarterly for RCIC TRIP FUNCTIONS (FUNCTIONAL UNITS 1-4).

30. Revise Table 4.3.5.1-1 footnote *, † from 31 days to 92 days.

31. Modify the TS Bases Section 3/4.3.5 to reference GE Topical Report GENE-770-06-2 which justifies the above proposed changes.

NEDC-30851P-A (Suppl 1) dated October 1988/GENE-770-06-1 dated February 1991

32. Add footnote * to allow up to 6 hours for required surveillance testing (TS 4.3.6).

33. Revise Table 3.3.6-1 ACTION 62 from one hour to twelve hours.

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(3) 0G90-319-32D, letter to Millard L. Wohl, NRC, from W. P. Sullivan and J. F. Klapproth, GE, "Clarification of Technical Specification Changes Given in ECCS Actuation Instrumentation Analysis", March 22, 1990.

34. Increase the channel functional test interval requirement in TS Table 4.3.6-1 from monthly to quarterly for the following TRIP FUNCTIONS.

    a. Rod Block Monitor (TRIP FUNCTION 1.)
    b. APRM (TRIP FUNCTION 2.)
    c. Scram Discharge Volume (TRIP FUNCTION 5.)
    d. Reactor Coolant System Recirculation Flow (TRIP FUNCTION 6.)

35. Modify the TS Bases Section 3/4.3.6 to reference GE Topical Report NEDC-30851P-A, Suppl 1 and GENE-770-06-1 which justifies the above changes.

GENE-770-06-1 Selected Instruments dated February 1991

36. Add footnote (e) to Minimum Channels Operable and TABLE NOTATIONS to allow up to six hours for required surveillance testing (TS Table 3.3.7.1-1).

37. Revise ACTION 74-a to allow up to 24 hours to restore an inoperable channel (TS Table 3.3.7.1-1).

38. Increase the channel functional test interval requirement in TS Table 4.3.7.1-1 from monthly to quarterly for Main Control Room Ventilation Radiation Monitors Trip function (INSTRUMENTATION 1.).

39. Modify the TS Bases Section 3/4.3.7 to reference GE Topical Report GENE-770-06-1 which justifies the above proposed changes.

40. Revise footnote (a) to Minimum Operable Channels to allow up to six hours for required surveillance testing (Table 3.3.9-1).

41. Increase the channel functional test interval requirement in Table 4.3.9.1-1 from monthly to quarterly for Feedwater System/Main Turbine Trip System (TRIP FUNCTION 1.).

42. Modify the TS Bases Section 3/4.3.9 to reference GE Topical Report GENE-770-06-1.

43. Add footnote *** to allow up to 6 hours for required surveillance testing (TS 4.2.2.1).

44. Revise TS 4.2.2.1a. from 31 days to 92 days.

45. Modify the TS Bases Section 3/4.4.2 to reference GE Topical Report GENE-770-06-1.

TS INDEX

46. Revise PAGE number for BASES FOR SECTION 3.0/4.0 3/4.3.7.

III. JUSTIFICATION FOR THE PROPOSED CHANGES

Niagara Mohawk has demonstrated the generic analyses completed by the BWR Owners' Group apply to NMP2 and completed the required plant-specific analyses. The following discussion provides the information requested by the NRC staff in plant-specific submittals while Section V contains the No Significant Hazards Consideration Evaluation completed pursuant to 10 CFR 50.92. As stated within the NRC SERs for Licensing Topical Reports (LTRs), three issues for NEDC-30851P-A and two issues for the remaining LTRs must be addressed to justify the applicability of the generic analyses to individual plants when specific facility Technical Specifications are considered for revision. The following is a discussion of those issues:

1. Confirm the applicability of the generic analyses to the specific facility. (This issue applies to all LTRs.)

<u>RESPONSE</u>

1.) Licensing Topical Report NEDC-30851P-A, Appendix L identifies NMP2 as a participating utility in the development of the RPS Technical Specification Improvement Analysis. Section 7.4 specifies that:

> " The evaluation found various differences between the RPS configuration of various plants and the generic plant. These differences include HFA relays, four scram contactors for BWR/2, sensor differences, scram parameter differences, and SDV sensor diversity differences. The assessment of these differences shows that while the HFA relays and the four scram contactors for BWR/2 would result in a higher overall RPS failure frequency, the improved technical specification intervals and allowable out-of-service times based on the generic plant would result in a net improvement to plant safety for plants with such differences. The effect of other differences on the RPS failure frequency is insignificant. Therefore, the generic results can be applied to plants in the BWROG Technical Specification Improvement Program."

Furthermore, included in this submittal is GE plant specific report MDE-78-0485 titled, "The Technical Specification Improvement Analysis for the Reactor Protection System for Nine Mile Point Station, Unit 2", which concludes in Section 4 that "the generic analysis in Reference 1 (NEDC-30851P-A) is applicable to NMP2." For a discussion of the differences between NMP2 and the generic plant analyzed in NEDC-30851P-A, see the response to Issue 3 below and the GE plant specific report MDE-78-0485. NMPC has reviewed the LTRs and plant-specific report and verified applicability to NMP2.

2.) Licensing Topical Report NEDC-30851P-A Suppl 2, Appendix A identifies Niagara Mohawk as a participating utility in the development of the BWR Isolation Instrumentation Common to RPS (Reactor Protection System) and ECCS (Emergency Core Cooling System) Technical Specification Improvement Analysis. Section 3.2 specifically analyzes BWR 5/6 plants. NMPC has reviewed this LTR and verified applicability to NMP2.

3.) Licensing Topical Report NEDC-31677P-A, Appendix E identifies Niagara Mohawk as a participating utility in the development of the BWR Isolation Actuation Instrumentation not common to the RPS or ECCS Technical Specification Improvement Analysis. Section 5.2 and Appendix C2 specifically analyzes BWR 5/6 plants. NMPC has reviewed this LTR and verified applicability to NMP2.

4.) Licensing Topical Report NEDC-30936P-A Appendix N (Part 1) and Appendix B (Part 2) identifies Niagara Mohawk as a participating utility in the development of the BWR ECCS actuation instrumentation Technical Specification Improvement Analysis. Section 5.5 (Part 2) specifically analyzes BWR 5/6 plants and in this submittal contains the NMP2 plant-specific General Electric Company Report RE-026 titled, "Technical Specification Improvement Analysis for the Emergency Core Cooling System Actuation Instrumentation for Nine Mile Point Nuclear Station, Unit 2" dated February 1987. NMPC has reviewed these LTRs and verified applicability to NMP2.

5.) Licensing Topical Report GENE-770-06-1, identifies application of changes to surveillance test intervals and allowed out-of-service times for selected Instrumentation Technical Specifications to all BWR plants. NMPC has reviewed this LTR and verified applicability to NMP2.

6.) Licensing Topical Report GENE-770-06-2 Section 3.2 concludes BWR5/6 plant changes are consistent with the changes justified by this Topical Report. NMPC has reviewed this LTR and verified applicability to NMP2.

7.) Licensing Topical Report NEDC-30851P-A Suppl 1 Appendix B identifies Niagara Mohawk as a participating utility in the development of the BWR Control Rod Block Instrumentation Technical Specification Improvement Analysis. Section 4.0 specifically addresses BWR 5 plants. NMPC has reviewed this LTR and verified applicability to NMP2.

2. Demonstrate that the drift characteristics for RPS, ECCS, Isolation, RCIC, Rod Block, and Selected channel instrumentation are bounded by the assumptions used in the LTRs when the functional test interval is extended from monthly to quarterly. (This issue applies to all LTRs.)

RESPONSE

This requirement as stated was difficult to address because the LTRs do not contain quantitative instrument drift assumptions. In order to resolve this concern, the BWR

Owners' Group and the NRC staff reviewed the BWR setpoint calculation methodology and decided that additional clarification was in order. As a result, the NRC staff has provided additional guidance in a letter from C. E. Rossi (NRC) to R. F. Janecek (BWROG) dated April 27, 1988 which specifically indicates that:

> "... licensees need only confirm that the setpoint drift which could be expected under the extended STIs has been studied and either (1) has been shown to remain within the existing allowance in the RPS and ESFAS instrument setpoint calculation or (2) that the allowance and setpoint have been adjusted to account for the additional expected drift."

NMP2 utilizes a setpoint calculation methodology for the RPS, ECCS, Isolation, RCIC, Rod Block and Selected instrumentation which calculates the Technical Specification Trip Setpoint by subtracting the Loop Drift from the Technical Specification Allowable Value. The current drift information provided by the equipment vendors and the applicable setpoint calculations for the NMP2 instruments has been reviewed. Trip unit calibration was assumed to be 18 months for the setpoint calculation methodology and therefore is not affected by the changes proposed in this amendment. Also, sensor calibration intervals for the NMP2 instrumentation addressed by these LTRs have been verified to be equal to or longer than once per quarter and are therefore unaffected by the proposed changes. Therefore, it can be concluded that the proposed increase in the surveillance intervals does not require any corresponding changes to the RPS setpoints because the drift characteristics for RPS channel instrumentation are bounded by the assumptions used in LTRs when the functional test interval is extended from weekly or monthly to quarterly.

3. Confirm that the differences between the parts of the RPS that perform the trip functions in the plant and those of the base case plant were included in the specific analysis done using the procedures of Appendix K to NEDC-30851P-A. (This issue applies to LTR NEDC-30851P-A only.)

<u>RESPONSE</u>

Included in this submittal is the General Electric Company Report MDE-78-0485, titled "Technical Specification Improvement Analysis for the Reactor Protection System." In summary, the report applies the generic study completed in Licensing Topical Report NEDC-30851P-A for modifying the RPS, to NMP2. This report utilizes the procedures of Licensing Topical Report NEDC-30851P-A, Appendix K to identify and evaluate the differences between the parts of the RPS that perform the trip functions at NMP2 and those analyzed in the generic study. The results of the analysis indicate that while the RPS configuration for NMP2 has several differences compared to the configuration in the base case, the differences do not have a significant impact. Therefore, the conclusions reached in NEDC-30851P-A apply to NMP2 and the plant-specific changes contained in this request are bounded by both the generic analysis and the NRCs' SER.

IV. CONCLUSION

As discussed in Item III above, Niagara Mohawk Power Corporation has satisfactorily addressed the three issues for NEDC-30851P-A and the two issues for the other GE License

Topical Reports (LTRs) which the NRC staff has indicated are necessary to implement the generic Technical Specification changes identified in the LTRs on a plant-specific basis. The first issue which applies to all LTRs required confirmation of the applicability of generic analyses to NMP2. Two required plant-specific plant reports on RPS and ECCS Instrumentation for NMP2 concluded that the generic analyses are applicable to NMP2. The information provided in the proprietary reports contained in this submittal address the differences between NMP2 and the generic analyses and, when applied with the conclusions contained in NEDC-30851P-A, and NEDC-30936P-A, justifies the proposed changes. NMPC has reviewed the LTRs and plant-specific reports and verified applicability to NMP2. The second issue required demonstrating why instrument setpoints can remain unchanged because drift assumptions remain the same. A concern exists for plants that have sensor calibration intervals shorter than the proposed quarterly functional tests. For those cases, an extension of the functional test interval would then require consideration of the effects on setpoint drift. The sensor calibration intervals for the NMP2 instrumentation addressed by those LTRs have been verified to be equal to or longer than once per quarter and are therefore unaffected by the proposed changes. Also, Trip Unit Calibration was assumed to be 18 months for the setpoint calculation methodology and setpoint drift is not affected by the changes proposed in this amendment. The third issue, which applies only to LTR NEDC-30851P-A for RPS, required confirmation that the base plant and NMP2 RPS trip function differences allowed NMP2 to be bounded by the LTR. General Electric Company Report MDE-78-0485 titled, "Technical Specification Improvement Analysis for Nine Mile Point Nuclear Station, Unit 2" confirmed that the NMP2 differences and their impact do not significantly affect the improvement in the Technical Specifications developed by the generic efforts of LTR NEDC-30851P-A.

Finally, recent approved BWR Owners' Group clarifications used in the development of NUREG 1434, "Improved Standard Technical Specifications" were implemented in the proposed allowable out-of-service times (AOTs) which enhance AOT wording to ensure a "loss-of-function" does not occur.

10CFR50.91 requires that at the time a licensee requests an amendment, it must provide to the Commission its analysis, using the standards in 10CFR50.92, about the issue of no significant hazards consideration. Therefore, in accordance with 10CFR50.91, the following evaluation has been performed:

V. NO SIGNIFICANT HAZARDS CONSIDERATION EVALUATION

1.) <u>The operation of Nine Mile Point Unit 2, in accordance with the proposed amendment, will not involve a significant increase in the probability or consequences of an accident previously evaluated.</u>

The generic analysis contained in Licensing Topical Report NEDC-30851P-A, assessed the impact of changing RPS surveillance test intervals (STIs) and allowable out-of-service times (AOTs) on the RPS failure frequency, the scram frequency and equipment cycling. Specifically, Section 5.7.4 "Significant Hazards Assessment" of NEDC-30851P-A states that:

"Fewer challenges to the safeguards system, due to less frequent testing of the RPS, conservatively results in a decrease of approximately one percent in core damage frequency. This decrease is based upon the following:

- Based on the plant specific experience presented in Appendix J, the estimated reduction in scram frequency (0.3 scrams/yr) represents a 1 to 2 percent decrease in core damage frequency based on the BWR plant specific Probabilistic Risk Assessments (PRAs) listed in Table 5-8.

- The increase in core damage frequency due to less frequent testing is less than one percent. This increase is even lower (less than 0.01 percent) when the changes resulting from the implementation of the Anticipated Transients Without Scram (ATWS) rule are considered. Therefore, this increase is more than offset by the decrease in CDF due to fewer scrams.

- The effect of reducing unnecessary cycles on RPS equipment, although not easily quantifiable also results in a decrease in core damage frequency.

- The overall impact on core damage frequency of the changes in allowable out-of-service time is negligible."

From this generic analysis, the BWR Owners' Group concluded that the proposed changes do not significantly increase the probability or consequences of an accident previously evaluated, namely the increase in probability of a scram failure due to RPS unavailability is insignificant, and the overall probability of an accident is actually decreased as the time the scram (RPS) instrumentation logic operates as designed is increased resulting in less inadvertent scrams during testing and repair. Furthermore, the proprietary plant-specific analysis contained in this submittal demonstrates that although NMP2 differs from the generic plant analyzed in Licensing Topical Report NEDC-30851P-A, the net effect of the plant-specific differences do not alter the generic conclusions. Also, the BWROG 92102 letter clarifications used in the development of NUREG 1434, "Improved Standard Technical Specifications", for AOTs which enhanced wording to ensure "loss of function" does not occur, results in no significant increase in the probability or consequences of an accident previously evaluated.

The generic analysis contained in Licensing Topical Reports NEDC-30851P-A Suppl 2/NEDC 31677P-A assessed the impact of changing STIs and AOTs for BWR Isolation Instrumentation common/not common to RPS and ECCS instrumentation. Specifically, Section 4.0 "Summary of Results" of NEDC-30851P-A Suppl 2 states that:

" The results indicate that the effects on probability of failure to initiate isolation are very small and the effects on probability or frequency of failure to isolate are negligible in nearly every case. In addition, the results indicate that increasing the AOT to 24 hours for tests and repairs has a negligible effect on the probability of failure of the isolation function. These combined with changes to the testing intervals and allowed out-of-service times for RPS and ECCS instrumentation provide a net improvement to plant safety and operations".

Section 5.6 "Assessment of Net Effect of Changes" of NEDC-31677P-A states that:

> "A reduction in core damage frequency (CDF) of at least as much as estimated in the ECCS instrumentation analysis can be expected when the isolation actuation instrumentation STIs are changed from one month to three months. The chief contributor to this reduction is the channel functional tests for the MSIVs. Inadvertent closure of the MSIVs will cause an unnecessary plant scram. This reduction in CDF more than compensates for any small incremental increase (10% or 1.0E-07/year) in calculated isolation function failure frequency when the STI is extended to three months".

From this generic analysis, the BWR Owners' Group concluded that the proposed changes do not significantly increase the consequences of an accident previously evaluated, namely the probability of an isolation failure due to isolation instrumentation unavailability is insignificant, and the increase in overall probability of an accident is actually decreased as the time the scram (RPS) instrumentation logic operates as designed is increased resulting in less inadvertent scrams during testing and repair. Also, the BWROG 0G90-579-32A letter clarifications used in the development of NUREG 1434, "Improved Standard Technical Specifications", for AOTs which enhanced wording to ensure "loss of function" does not occur, results in no significant increase in the probability or consequences of an accident previously evaluated.

The generic analysis contained in Licensing Topical Report NEDC-30936P-A (Parts 1 and 2) assessed the impact of changing STIs and AOTs for all BWR ECCS Actuation Instrumentation. Specifically, Section 4.0 "Technical Assessment of Changes" of NEDC-30936P-A (Part 2) states that:

> "The results indicate an insignificant (less than 5E-7 per year) increase in water injection function failure frequency when STIs are increased from 31 days to 92 days, AOTs for repair of the ECCS actuation instrumentation are increased from one hour to 24 hours, and AOT's for surveillance testing are increased from two to six hours. For all four BWR models the increase represents less than 4% increase in failure frequency. However, when other factors which influence the overall plant safety are considered, the net result is judged to be an improvement in plant safety".

From this generic analysis, the BWR Owners' Group concluded that the proposed changes do not significantly increase the probability or consequences of an accident previously evaluated, namely the increase in probability of a water injection failure due to ECCS instrumentation unavailability is insignificant and the net result is judged to be an improvement in plant safety. Furthermore, the proprietary plant-specific analysis contained in this submittal demonstrates that although NMP2 differs from the generic model analyzed in Licensing Topical Report NEDC-30936P-A, the net affect of the plant specific differences do not alter the generic conclusions. Also, the BWROG 0G90-319-32D letter clarifications used in the development of NUREG 1434, "Improved Standard Technical Specifications" for AOTs, results in no significant increase in the probability or consequences of an accident previously evaluated.

Bases contained in GE Topical Report GENE-770-06-1 assessed the impact of changing STIs and AOTs on selected systems failure frequency. Specifically, Section 2.0 "Summary" of GENE-770-06-1 states that:

> "Technical bases are provided for selected proposed changes to the instrumentation STIs and AOTs that were identified in the BWROG Improved BWR Technical Specification activity. These STI and AOT changes are consistent with approved changed to the RPS, ECCS, and isolation actuation instrumentation. These proposed changes do not result in a degradation to overall plant safety".

From these Bases, the BWR Owners' Group concluded that the proposed changes do not significantly increase the probability of an accident previously evaluated.

Bases contained in GE Topical Report GENE-770-06-2, assessed the impact of changing STIs and AOTs on BWR RCIC failure frequency. Specially, Section 2.0 "Summary" of GENE-770-06-2 states that:

> "The STI and AOT changes to the RCIC actuation instrumentation are justified based on their small effect on the water injection function unavailability and consistency with comparable changes to actuation instrumentation for the other ECCS sub systems".

From this bases, the BWR Owners' Group concluded that the proposed changes do not significantly increase the probability of an accident previously evaluated.

The generic analysis contained in Licensing Topical Report NEDC-30851P-A, Suppl 1, assessed the impact of changing Rod Block STIs on Rod Block failure frequency. Specifically, Section 5 (BNL's Tech. Eval. Report - Attachment 2 to the NRC SER) of NEDC-30851P-A Suppl 1 states that:

> "The BWR Owners' Group proposed changes to the Technical Specifications concerning the test requirements for BWR control rod block instrumentation. The changes consist of increasing the surveillance test intervals from one to three months. These test interval extensions are consistent with the already approved changes to STIs for the Reactor Protection System. The technical analysis reviewed and verified as documented herein indicates that there will be no significant changes in the availability of the control rod block function if these changes are implemented. In addition, there will be a negligible impact on the plant core melt frequency due to the decreased testing."

From this generic analysis, the BWR Owners' Group concluded that the proposed changes do not significantly increase the probability of an accident previously evaluated.

2.) <u>The operation of Nine Mile Point Unit 2, in accordance with the proposed amendment, will not create the possibility of a new or different kind of accident from any accident previously evaluated.</u>

The proposed change will not alter the physical characteristics of any plant systems or components and all safety-related systems and components remain within their applicable design limits. Thus, system and component performance is not adversely affected by this change, thereby assuring that the design capabilities of those systems and components are not challenged in a manner not previously assessed so as to create the possibility of a new or different kind of accident.

The addition of allowable out-of-service times (AOTs) and the increase in surveillance test intervals (STIs) does not alter the function of the ECCS, Isolation, Rod Block, and Selected Instrument Systems nor involve any type of plant modification and no new modes of plant operation are involved with these changes. Finally, the approved BWR Owners' Group clarifications are enhancements to allowable out-of-service times (AOTs) and do not create the possibility or a new of different kind of accident. Therefore, operation in accordance with the proposed amendment will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3.) <u>The operation of Nine Mile Point Unit 2, in accordance with the proposed amendment, will not involve a significant reduction in a margin of safety.</u>

The NRC staff has reviewed and approved the generic studies contained in the LTRs and has concurred with the BWR Owners' Group that the proposed changes do not significantly affect the availability of the RPS, ECCS, Isolation, Rod Block, or Selected Instrument Systems. The proposed addition of AOTs for the instruments addressed in the LTRs provide reasonable time for making repairs and performing tests. The lack of AOTs in the current Technical Specification (TS) creates a hurried atmosphere during repairs and tests which could cause an increased risk of error. Also, placing an individual channel in a tripped condition because no AOT exists, as in the current TS, increases the potential of an inadvertent scram. The proposed AOTs provide realistic times to complete the required actions without increasing the overall instrument failure frequency. The approved BWR Owners' Group Clarifications are enhancements to allowable out-of-service times (AOTs) and do not involve a significant reduction in a margin of safety.

The incorporation of extended STIs does not result in significant changes in the probability of instrument failure, as demonstrated by the LTRs. These changes, when coupled with the reduced probability of test-induced plant transients and equipment failures, result in an overall increase in the margin of safety. Also, the sensor calibration frequency has not changed. Therefore, assurance exists that the setpoints will not be affected by drift. Therefore, there is no reduction in the margin of safety.