ATTACHMENT I TO IPN-98-043

PROPOSED TECHNICAL SPECIFICATION CHANGES REGARDING

INSTRUMENT CHANNEL SURVEILLANCE INTERVALS TO

ACCOMMODATE A 24-MONTH OPERATING CYCLE

List of affected pages

Table 4.1-1, sheet 1
Table 4.1-1, sheet 3
Table 4.1-1, sheet 4
Table 4.1-1, sheet 5
Table 4.1-1, sheet 6
Table 4.1-3, sheet 1
Page 4.4-6
Page 4.4-7
Page 4.4-8
Page 4.4-10
Page 4.5-2
Page 4.8-1
Page 4.9-4
Page 4.11-3
Page 6-22

NEW YORK POWER AUTHORITY
INDIAN POINT 3 NUCLEAR POWER PLANT
DOCKET NO. 50-286
DPR-64

TABLE 4.1-1 (Sheet 1 of 6)

MINIMUM FREQUENCIES FOR CHECKS, CALIBRATIONS AND TESTS OF INSTRUMENT CHANNELS

Channel Description	Check	Calibrate	Test	Remarks
1. Nuclear Power Range	S	D (1) M (3)*	Q (2)** Q (4)	1) Heat balance calibration 2) Bistable action (permissive, rod stop, trips) 3) Upper and lower chambers for axial offset 4) Signal to Δ T
2. Nuclear Intermediate Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
3. Nuclear Source Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
4. Reactor Coolant Temperature	S ## (2)	24M	Q (1)	1) Overtemperature ΔT, overpower ΔT, and low T_{avg} 2) Normal Instrument check interval is once/shift T_{avg} instrument check interval reduced to every 30 minutes when: - T_{avg}-T_{ref} deviation and low T_{avg} alarms are not reset and, - Control banks are above 0 steps
5. Reactor Coolant Flow	S ##	24M	Q	
6. Pressurizer Water Level	S	24M	Q	
7. Pressurizer Pressure	S ##	24M	Q	High and Low

Channel Description	Check	Calibrate	Test	Remarks
e. Main Steam Lines Process Radiation Monitors (R-62A, R-62B, R-62C, and R-62D)	D	24M	Q	
f. Gross Failed Fuel Detectors (R-63A and R-63B)	D	24M	Q	
16. Containment Water Level Monitoring System:				
a. Containment Sump	N.A.	24M	N.A.	Narrow Range, Analog
b. Recirculation Sump	N.A.	24M	N.A.	Narrow Range, Analog
c. Containment Water Level	N.A.	24M	N.A.	Wide Range
17. Accumulator Level and Pressure	S	24M	N.A.	
18. Steam Line Pressure	S	24M	Q	
19. Turbine First Stage Pressure	S	24M	Q	
20a. Reactor Trip Relay Logic	N.A.	N.A.	TM	
20b. ESF Actuation Relay Logic	N.A.	N.A.	TM	
21. Turbine Trip Low Auto Stop Oil Pressure	N.A.	24M	N.A.	
22. DELETED	DELETED	DELETED	DELETED	
23. Temperature Sensor in Auxiliary Boiler Feedwater Pump Building	N.A.	N.A.	18M	
24. Temperature Sensors in Primary Auxiliary Building				
a. Piping Penetration Area	N.A.	N.A.	24M	
b. Mini-Containment Area	N.A.	N.A.	24M	
c. Steam Generator Blowdown Heat Exchanger Room	N.A.	N.A.	24M	

TABLE 4.1-1 (Sheet 4 of 6)

Channel Description	Check	Calibrate	Test	Remarks
25. Level Sensors in Turbine Building	N.A.	N.A.	24M	
26. Volume Control Tank Level	N.A.	24M	N.A.	
27. Boric Acid Makeup Flow Channel	N.A.	24M	N.A.	
28. Auxiliary Feedwater:				
a. Steam Generator Level	S	24M	Q	Low-Low
b. Undervoltage	N.A.	24M	24M	
c. Main Feedwater Pump Trip	N.A.	N.A.	24M	
29. Reactor Coolant System Subcooling Margin Monitor	D	24M	N.A.	
30. PORV Position Indicator	N.A.	N.A.	24M	Limit Switch
31. PORV Position Indicator	D	24M	24M	Acoustic Monitor
32. Safety Valve Position Indicator	D	24M	24M	Acoustic Monitor
33. Auxiliary Feedwater Flow Rate	N.A.	18M	N.A.	
34. Plant Effluent Radioiodine/ Particulate Sampling	N.A.	N.A.	18M	Sample line common with monitor R-13
35. Loss of Power				
a. 480v Bus Undervoltage Relay	N.A.	24M	M	
b. 480v Bus Degraded Voltage Relay	N.A.	18M	M	
c. 480v Safeguards Bus Undervoltage Alarm	N.A.	24M	M	
36. Containment Hydrogen Monitors	D	Q	M	

Amendment No. ~~38~~, ~~44~~, ~~54~~, ~~65~~, ~~67~~, ~~74~~, ~~93~~, ~~125~~, ~~136~~, ~~137~~, ~~142~~, ~~144~~, ~~150~~, ~~168~~, ~~169~~,

Channel Description	Check	Calibrate	Test	Remarks
37. Core Exit Thermocouples	D	24M	N.A.	
38. Overpressure Protection System (OPS)	D	18M (1)	18M	1) Calibration frequency for OPS sensors (RCS pressure and temperature) is 24 months
39. Reactor Trip Breakers	N.A.	N.A.	TM(1)	1) Independent operation of undervoltage and shunt trip attachments
			24M(2)	2) Independent operation of undervoltage and shunt trip from Control Room manual push-button
40. Reactor Trip Bypass Breakers	N.A.	N.A.	(1)	1) Manual shunt trip prior to each use
			24M(2)	2) Independent operation of undervoltage and shunt trip from Control Room manual push-button
			24M(3)	3) Automatic undervoltage trip
41. Reactor Vessel Level Indication System (RVLIS)	D	24M	N.A.	
42. Ambient Temperature Sensors Within the Containment Building	D	24M	N.A.	
43. River Water Temperature # (installed)	S	18M	N.A.	1) Check against installed instrumentation or another portable device
44. River Water Temperature # (portable)	S (1)	Q (2)	N.A.	2) Calibrate within 30 days prior to use and quarterly thereafter
45. Steam Line Flow	S	24M	Q	Engineered Safety Features circuits only

Table Notation

* By means of the movable incore detector system

** Quarterly when reactor power is below the setpoint and prior to each startup if not done previous month.

\# These requirements are applicable when specification 3.3.F.5 is in effect only.

\#\# The "each shift" frequency also requires verification that the DNB parameters (Reactor Coolant Temperature, Reactor Coolant Flow, and Pressurizer Pressure) are within the limits of Technical Specification 3.1.H.

S - Each Shift
W - Weekly
P - Prior to each startup if not done previous week
M - Monthly
NA - Not Applicable
Q - Quarterly
D - Daily
18M - At least once per 18 months
TM - At least every two months on a staggered test basis (i.e., one train per month)
24M - At least once per 24 months
6M - At least once per 6 months

TABLE 4.1-3 (Sheet 1 of 2)

FREQUENCIES FOR EQUIPMENT TESTS

		Check	Frequency
1.	Control Rods	Rod drop times of all control rods	24M
2.	Control Rods	Movement of at least 10 steps in any one direction of all control rods	Every 31 days during reactor critical operations
3.	Pressurizer Safety Valves	Set Point	24M
4.	Main Steam Safety Valves	Set Point	24M
5.	Containment Isolation System	Automatic actuation	24M
6.	Refueling System Interlocks	Functioning	Each refueling, prior to movement of core components
7.	Primary System Leakage	Evaluate	5 days/week
8.	Diesel Generators Nos. 31, 32 & 33 Fuel Supply	Fuel Inventory	Weekly
9.	Turbine Steam Stop Control Valves	Closure	Yearly
10.	L.P. Steam Dump System (6 lines)	Closure	Monthly
11.	Service Water System	Each pump starts and operates for 15 minutes (unless already operating)	Quarterly
12.	City Water Connections to Charging Pumps and Boric Acid Piping	Temporary connections available and valves operable	24M

I. Residual Heat Removal System

1. Test

a. (1) The portion of the Residual Heat Removal System that is outside the containment shall be tested either by use in normal operation or hydrostatically tested at 350 psig at the interval specified below.

(2) The piping between the residual heat removal pumps suctions and the containment isolation valves in the residual heat removal pump suction line from the containment sump shall be hydrostatically tested at no less than 100 psig at the interval specified below.

b. Visual inspection shall be made for excessive leakage during these tests from components of the system. Any significant leakage shall be measured by collection and weighing or by another equivalent method.

2. Acceptance Criterion

The maximum allowable leakage from the Residual Heat Removal System components located outside of the containment shall not exceed two gallons per hour.

3. Corrective Action

Repairs or isolation shall be made as required to maintain leakage within the acceptance criterion.

4. Test Frequency

Tests of the Residual Heat Removal System shall be conducted at least once per 24 months.

Basis

The containment is designed for a pressure of 47 psig. [1] While the reactor is operating, the internal environment of the containment will be air at essentially atmospheric pressure and an average maximum temperature of approximately 130°F. The Design Basis Accidents (DBA) that represent a challenge to the containment structure are a Loss of Coolant Accident (LOCA) and a Main Steam Line Break (MSLB). The limiting calculated peak containment pressure of 42.40 psig is a result of the MSLB [7], which is less than the stated design pressure of 47 psig. In addition, DBA analyses demonstrate that the calculated peak containment temperature will remain less than the Equipment Qualification (EQ) envelope temperature of 290 degrees F.

The containment structure is designed to contain, within established leakage limits, radioactive material that may be released from the reactor core following a DBA. The containment was designed with an allowable leakage rate of 0.1 weight percent of containment air per day. This leakage rate, used to evaluate offsite doses resulting from DBAs is defined in 10CFR 50 Appendix B as L_a; the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from the limiting DBA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing performed in accordance with the program required by Technical Specification 6.14. The minimum test pressure for this program, based on the current value of P_a is 42.40 psig. Analyses which established the previous minimum test pressure of 42.42 psig were performed to support an increase of the ultimate heat sink temperature. [4] The conclusions of that analysis regarding heat sink temperature, as incorporated by Technical Specification Amendment 98, remain valid.

Prior to initial operation, the containment was strength-tested at 54 psig and was leak-tested. The acceptance criterion for this pre-operational leakage rate test was established as 0.075 W/o (.75 L_a) per 24 hours at 40.6 psig and 263°F, which were the peak accident pressure and temperature conditions at that time. This leakage rate is consistent with the construction of the containment, [2] which is equipped with a Weld Channel and Penetration Pressurization System for continuously pressurizing the containment penetrations and the channels over certain containment liner welds. These channels were independently leak-tested during construction.

The safety analysis has been performed on the basis of a leakage rate of 0.10 W/o per day for 24 hours. With this leakage rate and with minimum containment engineered safeguards operating, the public exposure would be well below 10CFR100 values in the event of the design basis accident. [3]

Maintaining the containment operable requires compliance with the visual examinations and leakage rate test requirements of the Containment Leakage Rate Testing Program. Failure to meet air lock leakage limits specified in surveillance requirement 4.4.D does not invalidate the acceptability of these overall leakage determinations unless their contribution to overall Type A, B, and C leakage causes that to exceed limits. As left leakage prior to the first startup after performing a required 10 CFR 50, Appendix J, leakage test is required to be <0.6 L_a for combined Type B and C leakage, and < 0.75 L_a for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of ≤ 1.0 L_a. At ≤ 1.0 L_a the offsite dose consequences are bounded by the assumptions of the safety analysis. Surveillance requirement frequencies are as required by the Containment Leakage Rate Testing Program. Thus, Specification 1.12 (which allows Frequency extensions) does not apply. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

The Weld Channel and Containment Penetration Pressurization System (WCCPPS)[5] is in service continuously to monitor leakage from potential leak paths such as the containment personnel lock seals and weld channels, containment penetrations, containment liner weld channels, double-gasketed seals and spaces between certain containment isolation valves and personnel door locks. A leak would be expected to build up slowly and would, therefore, be noted before design limits are exceeded. Remedial action can be taken before the limit is reached. The sensitive leakage rate test of the WCCPPS demonstrates that pressurized containment penetrations and liner inner weld seams are within a leakage acceptance criteria that will allow the air receivers and the standby source of gas pressure, nitrogen cylinders, to provide a 24 hour supply of gas to the system. The WCCPPS is not credited for limiting containment isolation valve leakage and the sensitivity test is not used for demonstrating compliance with containment isolation valve leakage criteria. The frequency of the sensitive leakage test reflects an extension of 25 percent from the 24 month refueling cycle and, therefore, Specification 1.12 (which allows Frequency extensions) does not apply[10].

Maintaining containment air locks operable requires compliance with the leakage rate test requirements of the Containment Leakage Rate Testing Program. The surveillance requirement reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established during air lock and containment OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall containment leakage rate. The Frequency is required by the Containment Leakage Rate Testing Program. Thus, Specification 1.12 (which allows Frequency extensions) does not apply. During normal plant operation, containment personnel lock door seals are continuously pressurized after each closure by the WCCPPS. Whenever containment integrity is required, verification is made that seals repressurize properly upon closure of an air lock door. The verification meets the intent of the 10 CFR 50 Appendix J requirements.[8]

The maximum permissible inleakage rate from the containment isolation valves sealed with service water for the full 12-month period of post accident recirculation without flooding the internal recirculation pumps is 0.36 gpm per fan cooler.

REFERENCES

(1) FSAR - Section 5
(2) FSAR - Section 5.1.7
(3) FSAR - 14.3.5
(4) WCAP - 12269 Rev. 1, "Containment Margin Improvement Analysis for IP-3 Unit 3"
(5) FSAR - Section 6.6
(6) FSAR - Section 6.5
(7) Nuclear Safety Evaluation 98-3-013-MULT, "Integrated Safety Evaluation of 24-Month Cycle Instrument Channel Uncertainties," Revision 0, dated March 3, 1998.
(8) SECL-96-103, Indian Point Unit 3 Safety Evaluation of 24-Month Fuel Cycle Phase I Instrument Channel Uncertainties, June 1996
(9) Indian Point 3 Safety Evaluation Report, Supplement 2, December 1975.
(10) NRC Safety Evaluation Related to Amendment 129 to Operating License DPR-64.

2. Containment Spray System

   a. System tests shall be performed at least once per 24 months. The tests shall be performed with the isolation valves in the spray supply lines at the containment and the spray additive tank isolation valves blocked closed. Operation of the system is initiated by tripping the normal actuation instrumentation.

   b. The spray nozzles shall be checked for proper functioning at least every five years.

   c. The tests will be considered satisfactory if visual observations indicate all components have operated satisfactorily.

3. Containment Hydrogen Monitoring Systems

   a. Containment hydrogen monitoring system tests shall be performed at intervals no greater than six months. The tests shall include drawing a sample from the fan cooler units.

   b. The above tests will be considered satisfactory if visual observations and control panel indication indicate that all components have operated satisfactorily.

4.8 AUXILIARY FEEDWATER SYSTEM

Applicability

Applies to periodic testing requirements of the Auxiliary Feedwater System.

Objective

To verify the operability of the Auxiliary Feedwater System and its ability to respond properly when required.

Specification

1. a. Each auxiliary feedwater pump will be started manually from the control room at monthly intervals on a staggered test basis (i.e., one pump per month, so that each pump is tested once during a 3 month period) with full flow established to the steam generators at least once per 24 months.

   b. The auxiliary feedwater pumps discharge valves will be tested by operator action at intervals not greater than six months.

   c. Backup supply valves from the city water system will be tested at least once per 24 months.

2. Acceptance levels of performance shall be that the pumps start, reach their required developed head and operate for at least fifteen minutes.

3. At least once per 24 months,

   a. Verify that the recirculation valve will actuate to its correct position.

   b. Verify that each auxiliary feedwater pump will start as designated automatically upon receipt of an auxiliary feedwater actuation test signal.

Basis

The testing of the auxiliary feedwater pumps will verify their operability. The capacity of any one of the three auxiliary feedwater pumps is sufficient to meet decay heat removal requirements.

4. Interval of Inspection

a. The first inservice inspection of steam generators should be performed after six effective full power months but not later than completion of the first refueling outage.

b. Subsequent inservice inspections should be not less than 12 or more than 24 calendar months after the previous inspection.

c. If the results of two consecutive inspections, not including the preservice inspection, all fall into the C-1 category, the frequency of inspection may be extended to 40-month intervals. Also, if it can be demonstrated through two consecutive inspections that previously observed degradation has not continued and no additional degradation has occurred, a 40-month inspection interval may be initiated.

B. Corrective Measures

All leaking tubes and defective tubes should be: (1) plugged, or (2) repaired.

C. Reports

1. Following each inservice inspection of steam generator tubes, the number of tubes plugged and repaired in each steam generator shall be reported to the Commission within 15 days.

2. The complete results of the steam generator tube inservice inspection shall be reported in writing on an annual basis for the period in which the inspection was completed per Specification 6.9.2. This report shall include:

a. Number and extent of tubes inspected.

b. Location and percent of wall-thickness penetration for each indication of an imperfection.

c. Identification of the tubes plugged and the tubes repaired.

2. Visual inspection shall verify (1) that there are no visible indications of damage or impaired OPERABILITY, and (2) attachments to the foundations or supporting structure are secure. Snubbers which appear inoperable as a result of visual inspections shall be classified as unacceptable and may be reclassified acceptable for the purpose of establishing the next visual inspection interval, provided that (1) the cause of the rejection is clearly established and remedied for the particular snubber and for other snubbers that may be generically susceptible; and (2) the affected snubber is functionally tested in the as found condition and determined OPERABLE per Specification 4.11.B.5. However, when the fluid port of a hydraulic snubber is found to be uncovered, the snubber shall be declared inoperable via functional testing for the purpose of establishing the next visual inspection period. All snubbers connected to an inoperable common hydraulic fluid reservoir shall be counted as inoperable snubbers.

B. <u>Functional Testing</u>

1. At least once per 24 months during plant shutdown,a representative sample of 10% of all the safety-related hydraulic snubbers shall be functionally tested for operability, either in place or on a bench test. For each snubber that does not meet the requirement of 4.11.B.5, an additional 10% of the total installed of that type of hydraulic snubber shall be functionally tested. This additional testing will continue until no failures are found or until all snubbers of the same type have been functionally tested. The representative sample shall include each size and type of snubber in use in the plant.

2. The representative sample selected for functional testing should include the various configurations, operating environments, sizes and capacities of snubbers. At least 25% or the maximum possible if less than 25%, of the snubbers in the representative sample should include snubbers from the following three categories:

   a. The first snubber away from each reactor vessel nozzle.

6.12.2 The requirements of 6.12.1 above, shall also apply to each high radiation area in which the intensity of radiation is greater than 1000 mrem/hr. In addition, locked doors shall be provided to prevent unauthorized entry into such areas and the keys shall be maintained under the administrative control of the Shift Manager on duty and/or the plant Radiological and Environmental Services Manager or his designee.

6.13 ENVIRONMENTAL QUALIFICATION

6.13.1 Environmental qualification of electric equipment important to safety shall be in accordance with the provisions of 10 CFR 50.49. Pursuant to 10 CFR 50.49, Section 50.49 (d), the EQ Master List identifies electrical equipment requiring environmental qualification.

6.13.2 Complete and auditable records which describe the environmental qualification method used, for all electrical equipment identified in the EQ Master List, in sufficient detail to document the degree of compliance with the appropriate requirements of 10 CFR 50.49 shall be available and maintained at a central location. Such records shall be updated and maintained current as equipment is replaced, further tested, or otherwise further qualified.

6.14 CONTAINMENT LEAKAGE RATE TESTING PROGRAM

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak Test Program, dated September 1995" as modified by the following exception:

a. ANS 56.8 - 1994, Section 3.3.1: WCCPPS isolation valves are not Type C tested.

The maximum allowable primary containment leakage rate, L_a at a minimum test pressure equal to P_a, shall be 0.1% of primary containment air weight per day. P_a is the peak calculated containment internal pressure related to the design basis accident.

Leakage acceptance criteria are:

a. Containment leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the Type B and C tests and $\leq 0.75 L_a$ for Type A tests;

b. Air lock testing acceptance criteria are :

   1) Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$,

   2) For each door, leakage rate is $\leq 0.01\ L_a$ when pressurized to $\geq P_a$.

c. Isolation valves sealed with the service water system leakage rate into containment acceptance criterion is ≤ 0.36 gpm per fan cooler unit

ATTACHMENT II TO IPN-98-043

SAFETY EVALUATION FOR

PROPOSED TECHNICAL SPECIFICATION CHANGES REGARDING

INSTRUMENT CHANNEL SURVEILLANCE INTERVALS TO

ACCOMMODATE A 24-MONTH OPERATING CYCLE

NEW YORK POWER AUTHORITY
INDIAN POINT 3 NUCLEAR POWER PLANT
DOCKET NO. 50-286
DPR-64

Section I – Description of Changes

This application for amendment to Table 4.1-1 of the Indian Point 3 Technical Specifications proposes to change surveillance requirements for the following instrument channels to accommodate a 24-month operating cycle:

- Pressurizer Water Level (line item 6)
- Accumulator Level and Pressure (line item 17)
- Reactor Coolant System Subcooling Margin Monitor (line item 29)
- Core Exit Thermocouples (line item 37)
- Reactor Vessel Level Indication System (line item 41)

The existing calibration frequency requirement for these instrument channels will be changed from 18 months to 24 months. The existing 18-month surveillance requirement for the core exit thermocouples is characterized in Table 4.1-1 as a 'test.' In addition to changing the surveillance frequency from 18 months to 24 months, this application for amendment proposes to identify the required surveillance as a 'calibration' instead of a 'test,' consistent with the Standard Technical Specifications. Although thermocouple sensors are not subject to a calibration adjustment, the signal processing electronics are covered by calibration procedures.

The justification for the proposed new surveillance frequency follows the same approach that was used to support previously approved changes (References 1 and 2). These prior approvals included one-time extensions for Accumulator Level and Pressure, Reactor Coolant System Subcooling Margin Monitor (SMM), and Reactor Vessel Level Indication System (RVLIS). The increased surveillance frequency for these instruments was limited to a one-time extension because the process sensor drift was based on an evaluation criterion of 75% probability at a 75% confidence level (75/75). The analyses have been updated to reflect an evaluation criterion of 95/75 to support the proposed permanent surveillance interval extension.

Consistent with Generic Letter 91-04 (Reference 3), the Authority performed an integrated evaluation of surveillance interval increases to confirm acceptability with respect to plant safety analyses. Recent revisions of safety analyses included the effects of increased instrument drift over a maximum calibration interval of 30 months (24 months + 25%). This application for amendment contains a proposed change, regarding peak containment pressure, that reflects the results of the updated safety analyses.

This application for amendment also contains administrative changes to delete various notes that provided one-time extensions of certain tests and surveillances, as itemized below. These one-time extensions supported the planned schedule for refueling outage 9 that was completed in 1997.

- Table 4.1-1, sheets 3 & 6: one-time extension of accumulator level and pressure instrument channel calibration to no later than April 26, 1997.

- Table 4.1-1, sheets 4 & 6; one-time extension of reactor coolant system subcooling margin monitor instrument channel calibration to no later than May 12, 1997.

- Table 4.1-1, sheets 5 & 6; one-time extension of reactor vessel level indication system instrument channel calibration to no later than May 14, 1997.

- Table 4.1-3; one-time extension of pressurizer safety valve setpoint test to no later than May 31, 1997.

- Specification 4.4.I.4; one-time extension of boron injection tank integrity test to no later than May 31, 1997.

- Specification 4.5.A.2.b; one-time extension of containment spray nozzle test to no later than May 31, 1997.

- Specification 4.8.1.c; one-time extension of valve testing (city water backup supply to the auxiliary feedwater system) to no later than May 31, 1997.

- Specification 4.9.A.4.c; one-time extension of steam generator tube inspection to no later than May 31, 1997.

- Specification 4.11.B.1; one-time extension of snubber functional testing to no later than May 31, 1997.

Section II – Evaluation of Changes

Starting with cycle 9 (that began in August 1992), Indian Point 3 began operating on 24-month cycles, instead of the previous 18-month cycles. To avoid either a separate surveillance outage or an extended mid-cycle outage, changes are required to system surveillance intervals. Evaluation of the proposed changes included use of guidance provided in NRC Generic Letter 91-04. Factors considered in the proposed extension of surveillance frequency requirements included past equipment performance, results of loop accuracy and setpoint calculations, and effects on IP3 Emergency Operating Procedures, accident analyses, and safe plant shutdown.

A. Calibration Extension Program

The NRC staff has determined that licensees should address a number of issues in providing an acceptable basis for extending the calibration interval for instruments that are used to perform safety functions. NRC Generic Letter 91-04, Enclosure 2 specifies the licensee actions to be taken to address these issues. These actions include:

1. Confirming that instrument drift as determined by as-found and as-left calibration data from surveillance and maintenance records has not, except on rare occasions, exceeded acceptable limits for a calibration interval.

2. Confirming that the values of drift for each instrument type (make, model and range) and application have been determined with a high probability and a high degree of confidence; and providing a summary of the methodology and assumptions used to determine the rate of instrument drift with time based upon historical plant calibration data.

3. Confirming that the magnitude of instrument drift has been determined with a high probability and a high degree of confidence for a bounding calibration interval of 30 months for each instrument type and application that performs a safety function; and providing a list of the channels by technical specification section that identifies these instrument applications.

4. Confirming that a comparison of the projected instrument drift errors has been made with the values of drift used in the setpoint analysis; providing proposed technical specification changes to update trip setpoints to accommodate drift errors, if necessary, and providing a summary of the updated analysis conclusions to confirm that safety limits and safety analysis assumptions are not exceeded.

5. Confirming that the projected instrument errors caused by drift are acceptable for control of plant parameters to effect a safe shutdown with the associated instrumentation.

6. Confirming that all conditions and assumptions of the setpoint and safety analyses have been checked and are appropriately reflected in the acceptance criteria of plant surveillance procedures for channel checks, channel functional tests, and channel calibrations.

7. Providing a summary description of the program for monitoring and assessing the effects on increased calibration surveillance intervals on instrument drift and its effect on safety.

NYPA has reviewed past performance, analyzed instrument drift, revised loop accuracy/setpoint calculations based on updated drift and uncertainty values, and the affected instruments are in the drift monitoring program. The following sections describe how this was accomplished using guidance provided by Generic Letter 91-04.

B. <u>Instrument Drift Analysis</u>

Analyses of process sensor drift for the instrument channels included in this proposed amendment were performed using the Westinghouse Drift Evaluation Methodology, as described in prior applications for amendment reviewed and approved by the NRC (References 5 and 6). This method consists of a statistical analysis of data obtained during past calibrations to quantify the drift performance of the transmitter. Past calibration data (typically a minimum of four sets of as-found and as-left data points) are organized into computer spreadsheets and converted to percent of span drift. The resulting drift data is examined along with the site calibration records. This identifies and accounts for any data that is flawed by mechanistic causes such as obvious data recording errors, measurement and test equipment problems, or transmitters that were declared to be failed.

Following the initial screening, the data is examined with respect to distribution type using commercially available software. The sample data is then extrapolated to the population using descriptive statistics and tolerance factors, resulting in drift allowances at specified probability and confidence levels. If the data is determined not to be from a normal population, appropriate conservatism is introduced. The drift is established using a graded approach whereby the probability and confidence of the evaluation (95%/95% or 95%/75%) is selected depending on the safety significance of the function. In addition to the identification of any data that is flawed by mechanistic causes, this approach also may make use of statistical outlier techniques, whereby a data set may be removed from consideration if a majority of the points are determined to be flawed.

Finally, the drift data is examined for the presence of time dependence using a combination of statistical and visual checks. Adjustments are made as appropriate using linear regression to yield instrumentation drift allowances applicable to a 24-month fuel cycle plus 25% for a maximum allowable interval of 30 months.

The drift analysis results for the instrument channels addressed by this application for amendment are provided below.

- Pressurizer Water Level:

  Differential pressure level transmitters are used to monitor pressurizer water level during plant operation. The transmitters are Foxboro Model N-E13DH, with plant tag numbers LT-459, LT-460, and LT-461. The drift analysis result for these transmitters, based on 95% probability / 95% confidence level, is ±2.0% span random (not time dependent).

- Accumulator Level and Pressure:

  Accumulator level and pressure indications and alarms are used by control room operators to verify that these parameters are maintained within limits stated in the Technical Specifications (Section 3.3). Level instrumentation consists of two differential pressure transmitters (Rosemount 1151DP) for each of the four accumulators. The plant tag numbers are LT-934A through 934D and LT-935A through 935D. The drift analysis result for these transmitters, based on 95% probability / 75% confidence, is +0.5% span bias ±2.7% span random (not time dependent). Pressure instrumentation also consists of two transmitters for each of the four accumulators. Four of the transmitters (plant tag numbers PT-936A through 936D) are Foxboro Model N-E11GM and four transmitters (plant tag numbers PT-937A through 937D) are Foxboro Model E11GM. The drift analysis result applicable to both models, based on 95% probability / 75% confidence, is ±1.1% span random (not time dependent).

- Reactor Coolant System Subcooling Margin Monitor:

  The Reactor Coolant System Subcooling Margin Monitor (SMM) is used as an indication of adequate core cooling during post-accident conditions. The system uses core exit thermocouples (described in the next section) and wide range RCS pressure transmitters to measure the margin to saturation of the reactor coolant. Two Foxboro model N-E11GH pressure transmitters (plant tag numbers PT-402 and -403) are used for the wide range pressure measuring function. The drift analysis result for these transmitters, based on 95% probability / 75% confidence, is ±1.0% span random (not time dependent).

- Core Exit Thermocouples:

  The incore temperature monitoring system consists of 55 thermocouples that measure reactor coolant temperature at the core exit elevation for selected fuel assemblies. Thermocouple data is generally used for routine monitoring of core performance. However, 20 of the 55 thermocouples are designated as Regulatory Guide 1.97 qualified Core Exit Thermocouples (CET) for post-accident monitoring purposes. These 20 CETs are required by Technical Specification 3.5.7, and the surveillance requirement stated in Table 4.1-1 provides assurance of operability. Core exit temperature by itself and when combined with RCS pressure, as described in the previous section (SMM), provide a means of alerting the operator of inadequate core cooling during post-accident conditions. The CETs are chromel-alumel (Type K) thermocouples and are not subject to sensor drift experienced by other process sensors such as pressure and level transmitters. The drift allowance of ± 5°F, used for the CETs, is based on an extrapolation of industry data that was verified to be conservative by a qualitative evaluation of data obtained during past Indian Point 3 CET operability checks.

- Reactor Vessel Level Indication System:

  The Reactor Vessel Level Indication System (RVLIS) is used to provide an indication of adequate core cooling for certain hypothetical accident conditions. The system uses two wide-range pressure transmitters and four differential pressure transmitters to provide an indication of reactor coolant inventory in the reactor vessel under both static (RCPs stopped) and dynamic (RCPs running) conditions. The wide-range pressure transmitters are Rosemount model 1153GD9 (plant tag numbers PT-410 and -411) and are located outside containment. The drift analysis result for these transmitters is ±0.75% span random (not time dependent). The differential pressure transmitters are Barton model 752 (plant tag numbers LT-1311, -1312, -1321, and -1322) and are located outside containment. The differential pressure transmitters, in the 'dynamic range', measure the relative void content of the circulating coolant when the RCPs are running. The static condition, with the RCPs stopped, is measured in the 'full range'. The drift analysis result for these transmitters is ±2.0% span random (not time dependent) in the full range and ±1.4% span random with a ±1.3% limit of error in the dynamic range. Past performance data indicated a potential time dependency for these transmitters in the dynamic range, but not in the full range. The ±1.3% limit of error in the dynamic range was treated as a bias to account for the potential time dependency. The evaluations for the pressure transmitters and the differential pressure transmitters were performed based on 95% probability / 75% confidence.

C. Loop Accuracy / Setpoint Calculations

The loop accuracy / setpoint calculations for each of the affected instrument channels were updated using the 30-month instrument drift results described in the previous section. Uncertainties for other signal processing components in the instrument loop were also updated as appropriate to reflect the proposed new surveillance frequency. Revised uncertainty values were obtained based on evaluation of past performance or extrapolation of vendor data using methods as described in ISA RP67.04 (Reference 7). Vendor literature does not identify time-dependent uncertainties for indicators. Assurance of indicator operability is typically provided by channel checks performed each shift. The following sections provide specific information for each instrument channel addressed by this proposed license amendment.

- Pressurizer Water Level:

The pressurizer water level instrumentation provides signals for control room indication and alarms, and provides inputs to the reactor protection system and the pressurizer level control system. The pressurizer high level reactor trip is a backup to the pressurizer high pressure reactor trip and also prevents releasing water through the pressurizer safety valves for certain transient conditions. The loop accuracy / setpoint calculations were updated to include 30-month calibration uncertainties, including transmitter drift as previously described and extrapolated vendor-specified uncertainties for rack components that are not included in the quarterly channel functional test. The loop accuracy / setpoint calculations confirm that sufficient margin currently exists between the current reactor trip setting and the limits for the protective functions described above. In addition, the pressurizer level normal indication uncertainty due to increased sensor drift is within the readability of the indicator and has been addressed in the integrated safety evaluation. The post-accident indication uncertainties for the extended calibration interval meet the requirements of the Westinghouse Owners Group Emergency Response Guidelines (WOG ERGs). Revisions to the Indian Point 3 Emergency Operating Procedures (EOPs) will be made to reflect the results of the updated pressurizer level uncertainty calculation.

- Accumulator Level and Pressure:

The accumulators function to provide a passive source of emergency borated water to the reactor coolant system following a loss of coolant accident when RCS pressure is below the pressure in the accumulators. The accumulator water level and nitrogen cover pressure instrument channels provide indication and alarms in the control room. These instruments are used by plant operators to ensure that accumulator level and pressure are maintained within limits specified in the Technical Specifications (Section 3.3.A.3). The loop accuracy / setpoint calculations were updated to include 30-month calibration uncertainties, including transmitter drift as previously described and extrapolated vendor-specified uncertainties for rack and indicating components. Extrapolated uncertainties were obtained using methods described in ISA RP 67.04. The results of the revised loop accuracy calculations were used to establish new uncertainty values that have been addressed in the integrated evaluation, described in Section E. Revisions to the Alarm Response Procedures and the accumulator volume graph will be made to reflect the results of the updated calculations.

- Reactor Coolant System Subcooling Margin Monitor:

The RCS Subcooling Margin Monitor (SMM) was installed as part of the Inadequate Core Cooling Instrumentation in response to NUREG-0737. The system uses core exit thermocouples and wide range RCS pressure transmitters to provide an indication of the margin to saturation for the RCS coolant. Core exit temperature and the subcooling parameter are used in the EOPs to determine if core cooling is being maintained. Past performance of the SMM was evaluated for comparison to accuracy requirements previously established by Westinghouse, based on the use of this instrumentation to support the WOG ERGs.

Calculations were updated using 30-month drift allowances to support the proposed extension of the surveillance calibration interval. The updated calculations also used uncertainties associated with harsh environmental factors related to the pressure transmitter locations in containment. The updated uncertainty calculations demonstrated that the subcooling margin and core exit temperature uncertainties are acceptable because the design function of this instrument channel to support post-accident diagnosis of core cooling as reflected in the EOPs is maintained. No new revisions to the EOPs are required to account for the uncertainty values established by the updated calculations. The SMM and related uncertainties are not inputs into any UFSAR Chapter 14 safety analysis and therefore do not affect the analysis results.

- Core Exit Thermocouples:

The instrument loop for the core exit thermocouples (CETs) consists of the chromel-alumel (Type K) thermocouples, as previously described, and other signal processing components. The thermocouple wires are routed to Reference Junction Boxes (RJB) to make the transition to copper field wiring. Resistance temperature detectors (RTDs) provide a temperature compensation signal at this transition. The two RJBs (one per train) for the Regulatory Guide 1.97 CETs are located outside containment for protection from post-accident harsh environment conditions. The CET and RTD signals are routed to the ICCM-86 microcomputer, located in the control room, that provides signal conditioning, isolation, and data processing. The output from the ICCM-86 is transmitted to the Qualified Safety Parameter Display System (QSPDS) that displays core exit temperature. The QSPDS also uses the core exit temperature data in combination with RCS pressure signals to calculate and display subcooling margin. The updated uncertainty calculations demonstrated that the subcooling margin and core exit temperature uncertainties are acceptable because the design function of this instrument channel to support post-accident diagnosis of core cooling as reflected in the IP3 EOP is maintained. No new revisions to the EOPs are required to account for the uncertainty values established by the updated calculations. The CETs and related uncertainties are not inputs into any UFSAR Chapter 14 safety analysis and therefore do not affect the analysis results.

- Reactor Vessel Level Indication System:

The Reactor Vessel Level Indication System (RVLIS) was installed as part of the Inadequate Core Cooling Instrumentation in response to NUREG-0737. The system uses level and differential pressure measurements to provide indication of reactor vessel water inventory with and without the RCPs running. The RVLIS output is available to plant operators on the Qualified Safety Parameter Display System (QSPDS). This information is used in the EOPs to assist in the detection of the onset of inadequate core cooling conditions, to provide an indication of RCS inventory for terminating safety injection when pressurizer level can not be used, and to determine if a void exists in the reactor vessel head.

Past RVLIS transmitter performance was evaluated to update the loop uncertainty calculations for comparison to accuracy requirements previously established by Westinghouse, based on the use of this instrumentation to support the WOG ERGs. The updated calculations used 30-month drift allowances for the differential pressure transmitters and the wide range RCS pressure transmitters, as previously discussed. The updated uncertainties met all generic accuracy requirements except for the setpoint in the vicinity of the core mid-plane. For this setpoint, an evaluation of the Indian Point 3 plant-specific design basis small break LOCA response was performed to establish a revised EOP setpoint. Based on the revised setpoint, RVLIS continues to meet its licensing requirement of providing an anticipatory indication of inadequate core cooling (ICC), while preventing an unnecessary indication of ICC when ICC does not actually exist. Revisions to the EOPs will be made to reflect the results of the updated calculations. The RVLIS and related uncertainties are not inputs into any UFSAR Chapter 14 safety analyses and, therefore, do not affect the analysis results.

D. Drift Monitoring Program

In accordance with Generic Letter 91-04, the Authority has developed and implemented a drift monitoring program (DMP) to collect and evaluate calibration data. The purpose of the program is to confirm that as-found calibration data support the limits and assumptions used in the instrument drift analyses that support the extended surveillance intervals. The drift monitoring program is implemented by a plant procedure (IC-AD-034) that defines the program scope and method. During periodic surveillances, as-found calibration data which do not meet pre-established limits are entered into the DMP database for comparison to prior datapoints and drift acceptance criteria. Drift results are evaluated to verify that they do not exceed drift inputs used in existing setpoint / uncertainty calculations. In addition, drift results are reviewed to identify potential degraded instruments. Examples of potential instrument degradation include calibration results that indicate a bias for drift in one direction, increasing drift over several cycles, or when one of several identical loops is drifting in the opposite direction. Potential degraded instruments are added to an Instrument Awareness List, and degrading components are evaluated for generic impact on other similar components.

E. Integrated Evaluation of Surveillance Interval Extensions

This application for license amendment regarding extension of instrument surveillance intervals is in addition to several previously submitted by the Authority for Indian Point 3. Consistent with Generic Letter 91-04, the Authority has prepared an integrated evaluation (Reference 4) of the effects of the increased surveillance intervals on the UFSAR Chapter 14 safety analyses. The integrated evaluation included revised licensing basis safety analyses for small and large break LOCA, steam generator tube rupture, LOCA dose (radiological consequences), loss of normal feedwater, and loss of offsite (AC) power. The integrated evaluation concluded that all licensing basis safety analyses acceptance criteria continue to be met with the extended surveillance intervals.

The integrated evaluation for non-LOCA analyses demonstrates that minimum DNBR, maximum pressurizer water level, and maximum RCS and main steam system pressures will not exceed current limits. The integrated evaluation for LOCA analyses demonstrates that the acceptance criteria specified by 10CFR50.46 remain satisfied. The LOCA radiological dose calculations and the steam generator tube rupture accident analysis demonstrate that 10CFR100 offsite dose criteria are satisfied.

The containment integrity accident analysis demonstrates that peak calculated containment pressure is below the containment design pressure limit of 47 psig and the minimum Integrated Leak Rate Test pressure as currently specified in Technical Specification 6.14 and in the basis to Technical Specification 4.4. The maximum calculated peak accident containment pressure for the limiting LOCA and the Main Steam Line Break events were 40.54 psig and 42.40 psig, respectively. The containment analysis also demonstrates that acceptance criteria regarding environmental conditions (pressure and temperature) for equipment qualification remain satisfied.

This license amendment application also includes changes to Technical Specification 6.14 (Page 6-22) and the Basis for Technical Specification 4.4 (Pages 4.4-7 and 4.4-10). These changes are being made to reflect the revised safety analysis results and to update the reference documents. The proposed change to Technical Specification 6.14 uses the associated Standard Technical Specification format.

The Authority also evaluated (Reference 8) the acceptability of extending the surveillance interval of functional tests that implement the requirements of License Condition 2.L.2. This License Condition, established in 1981 in response to NUREG-0737 (Section III.D.1.1), requires a program to limit leakage from systems outside containment that would or could contain radioactive fluids during a serious transient or accident. The program is required to include system tests or inspections at a frequency not to exceed refueling cycle intervals. A change to the License Condition is not required because the implementing surveillance tests will continue to be performed at a refueling cycle interval. Since Indian Point 3 was operating on an 18-month fuel cycle at the time this license condition was established, the Authority evaluated the acceptability of a 24-month fuel cycle with respect to this requirement. The evaluation included a review of past test results and concluded that the stated objective of this license condition will continue to be satisfied with the implementing procedures performed at a frequency corresponding to the 24-month fuel cycle.

Section III – No Significant Hazards Evaluation

Consistent with the criteria of 10 CFR 50.92, the proposed changes to the Technical Specifications will not involve significant hazards consideration based on the following information:

(1) Does the proposed license amendment involve a significant increase in the probability or consequences of an accident previously analyzed?

Response:

No. The proposed license amendment to extend the calibration surveillance frequency of the following instrument channels is being made to support plant operation with a 24-month fuel cycle:

(a) Pressurizer Water Level
(b) Accumulator Level and Pressure

(c) Reactor Coolant System Subcooling Margin Monitor
(d) Core Exit Thermocouples
(e) Reactor Vessel Level Indication System

Changing the calibration intervals for these instrument channels neither directly nor indirectly affects the initiation or probability of any previously analyzed accident. The changes do not affect the integrity of any of the principal barriers against radiation release (fuel cladding, reactor vessel, and containment building). The ability of the plant to mitigate the consequences of any previously analyzed accidents is not adversely affected. Evaluation of the proposed change to the surveillance interval demonstrates that licensing basis safety analyses acceptance criteria and Indian Point 3 Emergency Operating Procedure (EOP) criteria continue to be met.

Item (a) provides an input to the Reactor Protection System (RPS) to initiate a reactor trip if the measured parameters exceed specified values. Item (b) is used by control room operators to ensure that the accident mitigation capability of the accumulators is maintained within specified limits. Items (c), (d), and (e) provide post-accident information to control room operators to support recovery efforts. Item (d) is also used to monitor core performance for fuel management activities.

The proposed new surveillance frequency for these instrument channels was evaluated using the guidance of Generic Letter 91-04. The basis for the changes includes a quantitative evaluation of instrument drift. Also, loop accuracy / setpoint calculations were updated to accommodate the extended surveillance period. Analyses and evaluations completed to assess the proposed increase in the surveillance interval demonstrate that the effectiveness of these instruments in fulfilling their respective functions is maintained. Channel checks required to be performed each shift or each day, according to Technical Specifications for the subject channels, will continue to be performed to provide assurance of instrument channel operability. Therefore, the proposed amendment does not involve a significant increase in the probability or consequences of any previously analyzed accident.

(2) Does the proposed license amendment create the possibility of a new or different kind of accident from any accident previously evaluated?

Response:

No. The increased calibration surveillance intervals for the above listed instrument channels were justified based on evaluation of past equipment performance and do not require any plant hardware changes or changes in normal system operation. Changing the calibration intervals for these channels neither directly nor indirectly has any means of creating the possibility of a new or different kind of accident. Certain alarm and EOP setpoint changes will be made consistent with the revised uncertainty calculations for the subject channels. These new setpoints and related operator responses support existing accident mitigation strategies and do not create the possibility of a new or different kind of accident from any previously analyzed. Therefore, there are no new failure modes introduced as a result of extending these surveillance intervals, and the proposed amendment does not create the possibility of a new or different kind of accident from any accident previously evaluated.

(3) Does the proposed amendment involve a significant reduction in a margin of safety?

Response:

No. Pressurizer water level instrumentation provides input to the reactor protection system and to the pressurizer water level control system. Pressurizer water level, as indicated by the selected control channel, is used to establish the initial condition pressurizer water level assumption for certain UFSAR Chapter 14 safety analyses. The proposed change to the calibration surveillance interval was evaluated using the criteria of 95% probability / 95% confidence level for process sensor drift. The loop accuracy / setpoint calculations were updated for the level channels to demonstrate the acceptability of the proposed increase in the surveillance interval. There are no changes required to the limiting safety system setting (LSSS) stated in the Technical Specifications for these channels. The LSSS for high pressurizer water level will remain at $\leq$92% of span. The margin of safety between the specified LSSS value required by Technical Specifications and the safety limit used in the UFSAR Chapter 14 safety analyses is unchanged.

The instrument channels for accumulator pressure and level do not provide input to the reactor protection system or the engineered safety features system. These instruments provide alarms and indication to control room operators to maintain accumulator cover gas pressure and water volume within specified limits. They are also used for establishing initial condition accumulator pressure and level assumptions for certain UFSAR Chapter 14 safety analyses. Accordingly, the process sensor drift analysis was performed using the criteria of 95% probability / 75% confidence level.

The remaining three instrument channels addressed by this proposed license change are used to provide indication of adequate core cooling following certain hypothetical accident conditions. These instrument channels are not associated with any margin of safety specified by the Technical Specifications, and they are not factors in any UFSAR Chapter 14 safety analyses. However, they are factored into the calculations of pertinent setpoints used in alarm response procedures and EOPs. The updated drift and uncertainty calculations and evaluations for these instrument channels demonstrate that applicable accuracy requirements for Indian Point 3 are satisfied with the proposed new surveillance intervals. The instrument channels will remain effective to support plant operator implementation of the Emergency Operating Procedures, which are consistent with the WOG ERGs.

Changing the calibration interval for these channels does not affect margin of safety for previously analyzed accidents. Also, the evaluation of related changes to UFSAR Chapter 14 safety analyses input assumptions has demonstrated that licensing basis safety analysis acceptance criteria and EOP criteria continue to be met, and previously existing margins based on these pertinent acceptance criteria continue to be maintained.

Therefore, the proposed amendment does not involve a significant reduction in a margin of safety.

Section IV – Impact of Changes

The proposed changes will not adversely affect the ALARA Program, the Security and Fire Protection Programs, or the Emergency Plan. This conclusion is based on the type of changes being made in comparison to the purpose, scope, and content of these programs.

The effects of the changes proposed in this application for amendment, and changes previously approved for other instrument channels have been addressed in an integrated safety evaluation. The results of the integrated evaluation are the basis for changes to Chapter 14 (Safety Analysis) of the UFSAR, the plant Design Basis Documents (DBD) for affected systems, and the Accident Analysis Basis Document (AABD). These changes will be incorporated in the next UFSAR update and revisions to the DBD and AABD will be made. The proposed increase in surveillance intervals does not involve changes to plant systems or components and there are no changes to the original SER conclusions. Instrumentation components addressed by this proposed amendment have already been added to the drift monitoring program. Setpoint Change Requests (SCRs) have been prepared to incorporate setpoint changes in affected plant documents such as alarm response procedures and EOPs. Processing of the SCRs will be completed as part of the implementing actions for this proposed Technical Specification amendment.

Section V - Conclusions

The incorporation of these changes:

a) will not significantly increase the probability nor the consequences of an accident or malfunction of equipment important to safety as previously evaluated in the Final Safety Analysis Report;
b) will not create the possibility for an accident or malfunction of a different type than any previously evaluated in the Final Safety Analysis Report; and
c) will not significantly reduce the margin of safety as defined in the bases for any Technical Specification.

Therefore, the proposed change will not adversely affect safe plant operation at IP3 because they do not involve significant hazards considerations as defined in 10 CFR 50.92.

Section VI - References

1. NRC Letter to New York Power Authority; "Issuance of Amendment 168 for Indian Point 3," G. Wunder to W. Cahill, Jr., dated September 5, 1996.

2. NRC Letter to New York Power Authority; "Issuance of Amendment 169 for Indian Point 3," G. Wunder to W. Cahill, Jr., dated September 24, 1996.

3. Generic Letter 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," dated April 2, 1991.

4. New York Power Authority Nuclear Safety Evaluation for Indian Point 3, NSE-98-3-013, "Integrated Safety Evaluation of 24-Month Cycle Instrument Channel Uncertainties," dated March 3, 1998.

5. NYPA letter (IPN-96-067) to NRC, "Proposed Changes to Technical Specifications Regarding Surveillance Intervals for Instrument Channels to Accomodate a 24-Month Operating Cycle," dated June 21, 1996.

6. NYPA letter (IPN-96-070) to NRC, "Proposed Changes to Technical Specifications Regarding Surveillance Intervals for Instrument Channels to Accomodate a 24-Month Operating Cycle," dated July 12, 1996.

7. Instrument Society of America, Recommended Practice ISA RP67.04, "Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation."

8. New York Power Authority report IP3-RPT-UNSPEC-02690, "Surveillance Interval Extension Project, Functional Test Extension Safety Evaluation," Revision 0, dated February 2, 1998.

ATTACHMENT III TO IPN-98-043

MARKUP OF PROPOSED TECHNICAL SPECIFICATION CHANGES REGARDING

INSTRUMENT CHANNEL SURVEILLANCE INTERVALS TO

ACCOMMODATE A 24-MONTH OPERATING CYCLE

NEW YORK POWER AUTHORITY
INDIAN POINT 3 NUCLEAR POWER PLANT
DOCKET NO. 50-286
DPR-64

TABLE 4.1-1 (Sheet 1 of 6)

MINIMUM FREQUENCIES FOR CHECKS, CALIBRATIONS AND TESTS OF INSTRUMENT CHANNELS

Channel Description	Check	Calibrate	Test	Remarks
1. Nuclear Power Range	S	D (1) M (3)*	Q (2)** Q (4)	1) Heat balance calibration 2) Bistable action (permissive, rod stop, trips) 3) Upper and lower chambers for axial offset 4) Signal to Δ T
2. Nuclear Intermediate Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
3. Nuclear Source Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
4. Reactor Coolant Temperature	S ## (2)	24M	Q (1)	1) Overtemperature ΔT, overpower ΔT, and low T_{avg} 2) Normal Instrument check interval is once/shift T_{avg} instrument check interval reduced to every 30 minutes when: - T_{avg}-T_{ref} deviation and low T_{avg} alarms are not reset and, - Control banks are above 0 steps
5. Reactor Coolant Flow	S ##	24M	Q	
6. Pressurizer Water Level	S	~~18M~~ 24M	Q	
7. Pressurizer Pressure	S ##	24M	Q	High and Low

TABLE 4.1-1 (Sheet 3 of 6)

Channel Description	Check	Calibrate	Test	Remarks
e. Main Steam Lines Process Radiation Monitors (R-62A, R-62B, R-62C, and R-62D)	D	24M	Q	
f. Gross Failed Fuel Detectors (R-63A and R-63B)	D	24M	Q	
16. Containment Water Level Monitoring System:				
a. Containment Sump	N.A.	24M	N.A.	Narrow Range, Analog
b. Recirculation Sump	N.A.	24M	N.A.	Narrow Range, Analog
c. Containment Water Level	N.A.	24M	N.A.	Wide Range
17. Accumulator Level and Pressure	S	~~18M***~~ 24M	N.A.	
18. Steam Line Pressure	S	24M	Q	
19. Turbine First Stage Pressure	S	24M	Q	
20a. Reactor Trip Relay Logic	N.A.	N.A.	TM	
20b. ESF Actuation Relay Logic	N.A.	N.A.	TM	
21. Turbine Trip Low Auto Stop Oil Pressure	N.A.	24M	N.A.	
22. DELETED	DELETED	DELETED	DELETED	
23. Temperature Sensor in Auxiliary Boiler Feedwater Pump Building	N.A.	N.A.	18M	
24. Temperature Sensors in Primary Auxiliary Building				
a. Piping Penetration Area	N.A.	N.A.	24M	
b. Mini-Containment Area	N.A.	N.A.	24M	
c. Steam Generator Blowdown Heat Exchanger Room	N.A.	N.A.	24M	

TABLE 4.1-1 (Sheet 4 of 6)

Channel Description	Check	Calibrate	Test	Remarks
25. Level Sensors in Turbine Building	N.A.	N.A.	24M	
26. Volume Control Tank Level	N.A.	24M	N.A.	
27. Boric Acid Makeup Flow Channel	N.A.	24M	N.A.	
28. Auxiliary Feedwater:				
a. Steam Generator Level	S	24M	Q	Low-Low
b. Undervoltage	N.A.	24M	24M	
c. Main Feedwater Pump Trip	N.A.	N.A.	24M	
29. Reactor Coolant System Subcooling Margin Monitor	D	~~18M****~~ 24M	N.A.	
30. PORV Position Indicator	N.A.	N.A.	24M	Limit Switch
31. PORV Position Indicator	D	24M	24M	Acoustic Monitor
32. Safety Valve Position Indicator	D	24M	24M	Acoustic Monitor
33. Auxiliary Feedwater Flow Rate	N.A.	18M	N.A.	
34. Plant Effluent Radioiodine/ Particulate Sampling	N.A.	N.A.	18M	Sample line common with monitor R-13
35. Loss of Power				
a. 480v Bus Undervoltage Relay	N.A.	24M	M	
b. 480v Bus Degraded Voltage Relay	N.A.	18M	M	
c. 480v Safeguards Bus Undervoltage Alarm	N.A.	24M	M	
36. Containment Hydrogen Monitors	D	Q	M	

Amendment No. ~~30~~, ~~44~~, ~~54~~, ~~65~~, ~~67~~, ~~74~~, ~~93~~, ~~125~~, ~~136~~, ~~137~~, ~~142~~, ~~144~~, ~~150~~, ~~168~~, 169

TABLE 4.1-1 (Sheet 5 of 6)

Channel Description	Check	Calibrate	Test	Remarks
37. Core Exit Thermocouples	D	~~N.A.~~ 24M	~~18M~~ N.A.	
38. Overpressure Protection System (OPS)	D	18M (1)	18M	1) Calibration frequency for OPS sensors (RCS pressure and temperature) is 24 months
39. Reactor Trip Breakers	N.A.	N.A.	TM(1)	1) Independent operation of under-voltage and shunt trip attachments
			24M(2)	2) Independent operation of under-voltage and shunt trip from Control Room manual push-button
40. Reactor Trip Bypass Breakers	N.A.	N.A.	(1)	1) Manual shunt trip prior to each use
			24M(2)	2) Independent operation of under-voltage and shunt trip from Control Room manual push-button
			24M(3)	3) Automatic undervoltage trip
41. Reactor Vessel Level Indication System (RVLIS)	D	~~18M*****~~ 24M	N.A.	
42. Ambient Temperature Sensors Within the Containment Building	D	24M	N.A.	
43. River Water Temperature # (installed)	S	18M	N.A.	1) Check against installed instrumentation or another portable device
44. River Water Temperature # (portable)	S (1)	Q (2)	N.A.	2) Calibrate within 30 days prior to use and quarterly thereafter
45. Steam Line Flow	S	24M	Q	Engineered Safety Features circuits only

Table Notation

* By means of the movable incore detector system

** Quarterly when reactor power is below the setpoint and prior to each startup if not done previous month.

*** This surveillance requirement may be extended on a one time basis to no later than April 26, 1997.

**** This surveillance requirement may be extended on a one time basis to no later than May 12, 1997.

***** This surveillance requirement may be extended on a one time basis to no later than May 14, 1997.

These requirements are applicable when specification 3.3.F.5 is in effect only.

The "each shift" frequency also requires verification that the DNB parameters (Reactor Coolant Temperature, Reactor Coolant Flow, and Pressurizer Pressure) are within the limits of Technical Specification 3.1.H.

S - Each Shift
W - Weekly
P - Prior to each startup if not done previous week
M - Monthly
NA - Not Applicable
Q - Quarterly
D - Daily
18M - At least once per 18 months
TM - At least every two months on a staggered test basis (i.e., one train per month)
24M - At least once per 24 months
6M - At least once per 6 months

TABLE 4.1-3 (Sheet 1 of 2)

FREQUENCIES FOR EQUIPMENT TESTS		
	Check	Frequency
1. Control Rods	Rod drop times of all control rods	24M
2. Control Rods	Movement of at least 10 steps in any one direction of all control rods	Every 31 days during reactor critical operations
3. Pressurizer Safety Valves	Set Point	24M*
4. Main Steam Safety Valves	Set Point	24M
5. Containment Isolation System	Automatic actuation	24M
6. Refueling System Interlocks	Functioning	Each refueling, prior to movement of core components
7. Primary System Leakage	Evaluate	5 days/week
8. Diesel Generators Nos. 31, 32 & 33 Fuel Supply	Fuel Inventory	Weekly
9. Turbine Steam Stop Control Valves	Closure	Yearly
10. L.P. Steam Dump System (6 lines)	Closure	Monthly
11. Service Water System	Each pump starts and operates for 15 minutes (unless already operating)	Quarterly
12. City Water Connections to Charging Pumps and Boric Acid Piping	Temporary connections available and valves operable	24M

* Pressurizer Safety Valve setpoint test due no later than May 1996 may be deferred until the next refueling outage but no later than May 31, 1997.

I. Residual Heat Removal System

1. Test

a. (1) The portion of the Residual Heat Removal System that is outside the containment shall be tested either by use in normal operation or hydrostatically tested at 350 psig at the interval specified below.

(2) The piping between the residual heat removal pumps suctions and the containment isolation valves in the residual heat removal pump suction line from the containment sump shall be hydrostatically tested at no less than 100 psig at the interval specified below.

b. Visual inspection shall be made for excessive leakage during these tests from components of the system. Any significant leakage shall be measured by collection and weighing or by another equivalent method.

2. Acceptance Criterion

The maximum allowable leakage from the Residual Heat Removal System components located outside of the containment shall not exceed two gallons per hour.

3. Corrective Action

Repairs or isolation shall be made as required to maintain leakage within the acceptance criterion.

4. Test Frequency

Tests of the Residual Heat Removal System shall be conducted at least once per 24 months. [See Note A, below]

Note A: Leak testing of the boron injection tank may be deferred until the next refueling outage (RO9), but no later than May 31, 1997.

Basis

The containment is designed for a pressure of 47 psig. [1] While the reactor is operating, the internal environment of the containment will be air at essentially atmospheric pressure and an average maximum temperature of approximately 130°F. The limiting peak containment temperature, based on LOCA containment response, is 261.5°F. [7] The peak containment pressure, also based on LOCA containment response, is approximately 42.39 psig. [7][8] The acceptance criteria was changed by amendment 98 to reflect analysis [4] done for the ultimate heat sink temperature increase. The acceptance criteria of 42.42 psig (based on the peak calculated pressure for a Main Steam Line Break analysis) is conservative with respect to the current LOCA peak pressure of 42.39.

SEE INSERT 4.4 A

Prior to initial operation, the containment was strength-tested at 54 psig and was leak-tested. The acceptance criterion for this pre-operational leakage rate test was established as 0.075 W/o (.75 L_a) per 24 hours at 40.6 psig and 263°F, which were the peak accident pressure and temperature conditions at that time. This leakage rate is consistent with the construction of the containment, [2] which is equipped with a Weld Channel and Penetration Pressurization System for continuously pressurizing the containment penetrations and the channels over certain containment liner welds. These channels were independently leak-tested during construction.

The safety analysis has been performed on the basis of a leakage rate of 0.10 W/o per day for 24 hours. With this leakage rate and with minimum containment engineered safeguards operating, the public exposure would be well below 10CFR100 values in the event of the design basis accident. [3]

Maintaining the containment operable requires compliance with the visual examinations and leakage rate test requirements of the Containment Leakage Rate Testing Program. Failure to meet air lock leakage limits specified in surveillance requirement 4.4.D does not invalidate the acceptability of these overall leakage determinations unless their contribution to overall Type A, B, and C leakage causes that to exceed limits. As left leakage prior to the first startup after performing a required 10 CFR 50, Appendix J, leakage test is required to be $<0.6\ L_a$ for combined Type B and C leakage, and $< 0.75\ L_a$ for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of $\leq 1.0\ L_a$. At $\leq 1.0\ L_a$ the offsite dose consequences are bounded by the assumptions of the safety analysis. Surveillance requirement frequencies are as required by the Containment Leakage Rate Testing Program. Thus, Specification 1.12 (which allows Frequency extensions) does not apply. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

INSERT 4.4A for page 4.4-7

The Design Basis Accidents (DBA) that represent a challenge to the containment structure are a Loss of Coolant Accident (LOCA) and a Main Steam Line Break (MSLB). The limiting calculated peak containment pressure of 42.40 psig is a result of the MSLB [7], which is less than the stated design pressure of 47 psig. In addition, DBA analyses demonstrate that the calculated peak containment temperature will remain less than the Equipment Qualification (EQ) envelope temperature of 290 degrees F.

The containment structure is designed to contain, within established leakage limits, radioactive material that may be released from the reactor core following a DBA. The containment was designed with an allowable leakage rate of 0.1 weight percent of containment air per day. This leakage rate, used to evaluate offsite doses resulting from DBAs is defined in 10CFR 50 Appendix B as L_a; the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from the limiting DBA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing performed in accordance with the program required by Technical Specification 6.14. The minimum test pressure for this program, based on the current value of P_a is 42.40 psig. Analyses which established the previous minimum test pressure of 42.42 psig were performed to support an increase of the ultimate heat sink temperature. [4] The conclusions of that analysis regarding heat sink temperature, as incorporated by Technical Specification Amendment 98, remain valid.

The maximum permissible inleakage rate from the containment isolation valves sealed with service water for the full 12-month period of post accident recirculation without flooding the internal recirculation pumps is 0.36 gpm per fan cooler.

REFERENCES

(1) FSAR - Section 5
(2) FSAR - Section 5.1.7
(3) FSAR - 14.3.5
(4) WCAP - 12269 Rev. 1, "Containment Margin Improvement Analysis for IP-3 Unit 3"
(5) FSAR - Section 6.6
(6) FSAR - Section 6.5
~~(7) SECL 92 131, Indian Point Unit 3 High Head Safety Injection Flow Changes Safety Evaluation, June 1992~~
(8) SECL-96-103, Indian Point Unit 3 Safety Evaluation of 24-Month Fuel Cycle Phase I Instrument Channel Uncertainties, June 1996
(9) Indian Point 3 Safety Evaluation Report, Supplement 2, December 1975.
(10) NRC Safety Evaluation Related to Amendment 129 to Operating License DPR-64.

(7) Nuclear Safety Evaluation 98-3-013 MULT, "Integrated Safety Evaluation of 24-Month Cycle Instrument Channel Uncertainties," Revision 0, dated March 3, 1998.

2. Containment Spray System

a. System tests shall be performed at least once per 24 months. The tests shall be performed with the isolation valves in the spray supply lines at the containment and the spray additive tank isolation valves blocked closed. Operation of the system is initiated by tripping the normal actuation instrumentation.

b. The spray nozzles shall be checked for proper functioning at least every five years. [See Note A, below]

c. The tests will be considered satisfactory if visual observations indicate all components have operated satisfactorily.

3. Containment Hydrogen Monitoring Systems

a. Containment hydrogen monitoring system tests shall be performed at intervals no greater than six months. The tests shall include drawing a sample from the fan cooler units.

b. The above tests will be considered satisfactory if visual observations and control panel indication indicate that all components have operated satisfactorily.

Note A: Testing of the spray nozzles may be deferred until the next refueling outage (RO9), but no later than May 31, 1997.

4.8 AUXILIARY FEEDWATER SYSTEM

Applicability

Applies to periodic testing requirements of the Auxiliary Feedwater System.

Objective

To verify the operability of the Auxiliary Feedwater System and its ability to respond properly when required.

Specification

1. a. Each auxiliary feedwater pump will be started manually from the control room at monthly intervals on a staggered test basis (i.e., one pump per month, so that each pump is tested once during a 3 month period) with full flow established to the steam generators at least once per 24 months.

   b. The auxiliary feedwater pumps discharge valves will be tested by operator action at intervals not greater than six months.

   c. Backup supply valves from the city water system will be tested at least once per 24 months. [See Note A, below]

2. Acceptance levels of performance shall be that the pumps start, reach their required developed head and operate for at least fifteen minutes.

3. At least once per 24 months,

   a. Verify that the recirculation valve will actuate to its correct position.

   b. Verify that each auxiliary feedwater pump will start as designated automatically upon receipt of an auxiliary feedwater actuation test signal.

Basis

The testing of the auxiliary feedwater pumps will verify their operability. The capacity of any one of the three auxiliary feedwater pumps is sufficient to meet decay heat removal requirements.

Note A: Testing of the backup supply valves may be deferred until the next refueling outage (RO9), but no later than May 31, 1997.

4. Interval of Inspection

a. The first inservice inspection of steam generators should be performed after six effective full power months but not later than completion of the first refueling outage.

b. Subsequent inservice inspections should be not less than 12 or more than 24 calendar months after the previous inspection.

c. If the results of two consecutive inspections, not including the preservice inspection, all fall into the C-1 category, the frequency of inspection may be extended to 40-month intervals.* Also, if it can be demonstrated through two consecutive inspections that previously observed degradation has not continued and no additional degradation has occurred, a 40-month inspection interval may be initiated.

B. Corrective Measures

All leaking tubes and defective tubes should be: (1) plugged, or (2) repaired.

C. Reports

1. Following each inservice inspection of steam generator tubes, the number of tubes plugged and repaired in each steam generator shall be reported to the Commission within 15 days.

2. The complete results of the steam generator tube inservice inspection shall be reported in writing on an annual basis for the period in which the inspection was completed per Specification 6.9.2. This report shall include:

   a. Number and extent of tubes inspected.

   b. Location and percent of wall-thickness penetration for each indication of an imperfection.

   c. Identification of the tubes plugged and the tubes repaired.

* Except that the surveillance related to the steam generator tube inspection due no later than July 1996, may be deferred until the next refueling outage but no later than May 31, 1997.

2. Visual inspection shall verify (1) that there are no visible indications of damage or impaired OPERABILITY, and (2) attachments to the foundations or supporting structure are secure. Snubbers which appear inoperable as a result of visual inspections shall be classified as unacceptable and may be reclassified acceptable for the purpose of establishing the next visual inspection interval, provided that (1) the cause of the rejection is clearly established and remedied for the particular snubber and for other snubbers that may be generically susceptible; and (2) the affected snubber is functionally tested in the as found condition and determined OPERABLE per Specification 4.11.B.5. However, when the fluid port of a hydraulic snubber is found to be uncovered, the snubber shall be declared inoperable via functional testing for the purpose of establishing the next visual inspection period. All snubbers connected to an inoperable common hydraulic fluid reservoir shall be counted as inoperable snubbers.

B. Functional Testing

1. At least once per 24 months* during plant shutdown, a representative sample of 10% of all the safety-related hydraulic snubbers shall be functionally tested for operability, either in place or on a bench test. For each snubber that does not meet the requirement of 4.11.B.5, an additional 10% of the total installed of that type of hydraulic snubber shall be functionally tested. This additional testing will continue until no failures are found or until all snubbers of the same type have been functionally tested. The representative sample shall include each size and type of snubber in use in the plant.

2. The representative sample selected for functional testing should include the various configurations, operating environments, sizes and capacities of snubbers. At least 25% or the maximum possible if less than 25%, of the snubbers in the representative sample should include snubbers from the following three categories:

   a. The first snubber away from each reactor vessel nozzle.

* Snubber functional testing due no later than May 1996 may be deferred until the next refueling outage but no later than May 31, 1997.

6.12.2 The requirements of 6.12.1 above, shall also apply to each high radiation area in which the intensity of radiation is greater than 1000 mrem/hr. In addition, locked doors shall be provided to prevent unauthorized entry into such areas and the keys shall be maintained under the administrative control of the Shift Manager on duty and/or the plant Radiological and Environmental Services Manager or his designee.

6.13 ENVIRONMENTAL QUALIFICATION

6.13.1 Environmental qualification of electric equipment important to safety shall be in accordance with the provisions of 10 CFR 50.49. Pursuant to 10 CFR 50.49, Section 50.49 (d), the EQ Master List identifies electrical equipment requiring environmental qualification.

6.13.2 Complete and auditable records which describe the environmental qualification method used, for all electrical equipment identified in the EQ Master List, in sufficient detail to document the degree of compliance with the appropriate requirements of 10 CFR 50.49 shall be available and maintained at a central location. Such records shall be updated and maintained current as equipment is replaced, further tested, or otherwise further qualified.

6.14 CONTAINMENT LEAKAGE RATE TESTING PROGRAM

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163 "Performance-Based Containment Leak Test Program, dated September 1995" as modified by the following exception:

a. ANS 56.8 - 1994, Section 3.3.1: WCCPPS isolation valves are not Type C tested.

~~The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 42.39 psig. The minimum test pressure is 42.42 psig.~~

~~The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 0.1% of primary containment air weight per day.~~

Leakage acceptance criteria are:

a. Containment leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the Type B and C tests and $\leq 0.75 L_a$ for Type A tests;

b. Air lock testing acceptance criteria are :

1) Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$,

2) For each door, leakage rate is $\leq 0.01\ L_a$ when pressurized to $\geq P_a$.

c. Isolation valves sealed with the service water system leakage rate into containment acceptance criterion is ≤ 0.36 gpm per fan cooler unit

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The maximum allowable primary containment leakage rate, L_a at a minimum test pressure equal to P_a, shall be 0.1% of primary containment air weight per day. P_a is the peak calculated containment internal pressure related to the design basis accident.

COMMITMENT LIST FOR IPN-98-043

Number	Commitment	Due
IPN-98-043-01	The Authority will update the FSAR to reflect the results of revised safety analyses that include the effects of increased instrument calibration surveillance intervals.	Next applicable FSAR update period.
IPN-98-043-02	The Authority will revise the ARP and EOP setpoints to reflect the updated instrument loop uncertainty calculations associated with the instrument channels addressed by this Technical Specification amendment request.	Prior to exceeding surveillance interval of 18 months + 25%.