FAQ LOG 11				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
11.16	PP01	**Question** For Security Intrusion Detection Systems (IDS), if the number of IDS false alarms exceeds "x" number per hour, the licensee considers the IDS segment failed and implements compensatory measures for the IDS segment. There are two questions: 1) If an IDS segment is declared failed (but left in service) and security personnel's inspection identifies no reason to contact the maintenance organization for resolution and operability testing of the IDS segment by security personnel is successful (without performing corrective maintenance) should compensatory hours be counted for the time period that the IDS was considered as failed? 2) If an IDS segment is declared failed (but left in service) and security personnel contact the maintenance organization for resolution, the maintenance evaluation does not disclose any malfunction, and operability testing of the IDS segment by security personnel is successful, should compensatory hours be counted for the time period that the IDS was considered as failed?	7/12/00 Discussed. On hold for review. 8/3/00 NEI proposed response. 8/29 NEI response revision. 9/21 – Discussed. On hold. 10/27 ComEd revision of FAQ and proposed response. 10/31 – Discussed. NRC to review proposed revision. 12/6 – Discussed. HOLD for discussion on 1/10/01 1/10/01 – Discussed. On hold. NRC to discuss with region III. **2/8/01 – NEI response revision. Tentative Approval** **3/2/01 – Approved. Post April 1, 2001.**	ComEd

Attachment 10

FAQ LOG 11

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: 1. Yes. If the false alarms exceed the station security program limit, then the compensatory hours are counted regardless of which personnel evaluate the condition; provided it is in accordance with the station security program. In the absence of guidance in the security program, qualified individuals can disposition the condition. 2. Yes. See answer to 1.		

FAQ Log 15				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
15.8	MS01	**Question:** The Emergency AC Power System monitored function for the indicator is, "The ability of the emergency generators to provide AC power to the class 1E buses upon a loss of off-site power." However, on page 26 of NEI 99-02, Rev 0 under testing where simple operator action is allowed for restoration, it states "The intent of this paragraph is to allow licensees to take credit for restoration actions that are virtually certain to be successful (i.e., probability nearly equal to 1) during accident conditions." For purposes of this indicator are we to assume a simultaneous loss of off-site power and also accident conditions? This may make a difference on the diesel generator response, operator restoration actions and ultimately whether or not we count unavailability during our surveillance test runs. **Response:** Yes, you should assume a simultaneous loss of off-site power and also accident conditions if they are specified in your design and licensing bases.	Introduced 10/31 12/5 NEI Response added 1/10/2001 – Discussed. Hold. W. Warren to contact VY. 2/5/01 – Alternate response provided by NEI **2/8/01 – Response revised. Use alternate resposne. Tentative Approval as revised.** **3/2/01 – Approved. Post 3/2/01.**	VY
15.12	MS01 MS02 MS03 MS04	**Question:** 1. Should support system unavailability be counted in the monitored safety system unavailability PI if analysis or engineering judgement has determined that the support system can be restored to available status such that the monitored system remains available to perform its intended safety function? 2. Do the criteria for determining availability described in NEI 99-02, Revision 0, page 26 lines 31-40 apply to this situation?	Introduced 10/31 12/5/00 – NEI, Licensee proposed response added. 3/2/01 – Discussed. FAQ to be discussed as part of SSU focus group.	ComEd

FAQ Log 15

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Licensee Proposed Response: 1. No. During both testing and non-testing situations, the criteria described in NEI 99-02, Revision 0, page 33, lines 7-9 should apply, "In these cases, analysis or sound engineering judgment may be used to determine the effect of support system unavailability on the monitored system." If the analysis or engineering judgment determines that the unavailability of the support system does not impair the ability of the monitored system to perform its intended safety function, then the support system unavailability should not be counted in the monitored system PI. For example, if engineering analysis determines that the unavailability of a ventilation support system for the emergency diesel generator does not adversely impact the availability of the emergency diesel generator to perform its intended function, the unavailability of the support system would not be counted in the emergency diesel generator PI. The engineering analysis must evaluate such things as; the length of time between an event and the time the ventilation system is required to be available to support the safety function of the emergency diesel generator, the complexity the actions required by plant operators to restore the availability of the ventilation system, and the probability of success for the restoration actions. Restoration actions should be contained in a written procedure and must not require diagnosis or repair. The engineering analysis must provide a high degree of assurance that the unavailability of the ventilation support system does not impact the ability of the emergency diesel generator to perform its safety function. This treatment is consistent with maintenance rule and PRA. 2. No. In NEI 99-02, Revision 0, page 26, lines 31-40, criteria for exclusion of planned unavailability for testing activities of monitored systems are described. The criteria established in this section describe required actions or barriers which must be in place during *testing* so that unavailability of the monitored system is not counted in the monitored system PI.		

FAQ Log 16				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
16.1	IE01	**Question:** Following a forced outage during which work was performed on a reactor coolant pump motor to reduce vibration, the unit was restarted. It should be noted the forced outage was not the result of the reactor coolant pump problem; the unit tripped for other reasons. During the unit restart while increasing power, an annunciator came in indicating excessive vibration on the reactor coolant pump in question. The annunciator response procedure directed the unit operator to an emergency shutdown procedure. The emergency shutdown procedure then instructed the unit operator to rapidly shut down the unit, however this particular procedure accomplishes rapid shut down without a reactor trip in that it directs the power level to be brought down to a nominal value prior to instructing the reactor trip breaker to be opened. This shutdown sequence is consistent with normal shutdown procedures. Would this be considered an unplanned SCRAM or an unplanned power change? **Response:** It would count as an unplanned power change.	Introduced 12/6 3/2/01 – Discussed. TVA to provide information on EOP language.	TVA
16.2	MS03	**Question:** The Nuclear Service Water (NSW) system provides assured suction supply to the Auxiliary Feedwater (AFW) system under certain accident scenarios. During a postulated seismic event concurrent with a loss of offsite power (LOOP), the normal non-safety related, non-seismic condensate suction sources are assumed to be unavailable. Flow testing is performed under the plant's Generic Letter 89-13 program to assure adequate flow. The alignment used in this testing renders this flowpath unavailable to fulfill its assured supply function. However, the normal condensate source remains available. Recently a reactor trip occurred during the performance of this testing. The testing was terminated, but due to resource limitations during event recovery, the normal operating alignment was not restored. Therefore, the assured AFW supply remained unavailable for an extended period. However, during the event, the AFW system started automatically on a valid autostart signal (2/4 lo-lo SG level in 1/4 SGs, loss of both main feedwater pumps) and continued to operate for a period of two days to maintain steam generator levels drawing suction from the normal condensate supply. Previously, whenever the assured supply has been unavailable, whether for testing or other alignments, the entire AFW system has been deemed unavailable based on a hypothetical design basis event scenario. However, the real world event described above results in the dichotomy of calling a system unavailable because its assured supply is unavailable while it was in fact fulfilling its design basis function. Under the NEI 99-02 guidelines, how should unavailability be addressed in conditions where the assured supply is unavailable with the normal supply available? **Response:** The purpose of the safety system unavailability indictor is to monitor the readiness of important safety systems to perform their safety functions in response to off-normal events or accidents. Since the assumed suction supply to the AFW system is credited for off-normal events or accidents, the unavailable time should be counted unless the system could have been promptly restored by a dedicated operator stationed for that purpose during the testing	Introduced 12/6 2/5/01 – Response added by NEI. **3/2/01 – Tentative Approval.**	Catawba

FAQ Log 16

Temp No.	PI	Question/Response	Status	Plant/ Co.
16.3	MS01 MS02 MS03 MS04	**Question:** Concerning removal of fault unavailable hours NEI 99-02 states: "Fault exposure hours associated with a single item may be removed after 4 quarters have elapsed from discovery…" In the case we are considering, the hours were discovered in the third calendar quarter. When do the four elapsed quarters begin? At the start of the fourth calendar quarter? and end at the conclusion of next year's third quarter? If the period of calculation of the indicator value was only four calendar quarters beginning the quarter after they occurred, and the fault unavailable hours are reported in the quarter in which they occurred, what's the point in removing them after they are no longer a factor in the calculation of the indicator? "Fault exposure hours are removed by submitting a change report that provides a revision to the reported hours for the affected quarter(s). The change report should include a comment to document this action." **Response:** The fault exposure hours should be reported for third quarter data and may be removed with the submittal of the next year's third quarter data provided the criteria for removing fault exposure hours are met. All safety system unavailability performance indicators calculate train unavailability for 12 quarters. Therefore, the situation you describe would not exist.	Introduced 12/6 2/5/01 – NEI response added. **3/2/01 – Tentative Approval.**	IP2
16.4	BI01	**Question:** NRC Performance Indicator BI-01 monitors the integrity of the fuel cladding. We are required to report the maximum monthly RCS activity in micro-Curies per gram dose equivalent Iodine-131 and express it as a percentage of the technical specification limit. FAQ 226 asks if licensees with limits more restrictive than the technical specification limit should use the more restrictive limit or the TS limit. The FAQ answer states that the licensee should use the most restrictive regulatory limit unless it is "insufficient to assure plant safety." If administrative controls are imposed "... to ensure that TS limits are met and to ensure the public health and safety, that limit should be used for this PI." Vermont Yankee has a Basis for Maintaining Operation (BMO) that is in effect that limits the Reactor Coolant System to 0.05 uCi/gm I-131 dose equivalent. This BMO, 98-36, entitled "Effect of Main steam Tunnel and Turbine Building HELBs on the HVAC Rooms," is concerned with Control Room habitability and the regulatory dose limits to the operators. It states that there is no concern with increased radiological dose to the public from the VY HELB off-site dose analyses in FSAR Section 14.6. FAQ 226 mentions the concern for both assuring plant safety and public health and safety as the intent for the more restrictive administrative controls that may be in effect. NRC Administrative Letter 98-10, which is mentioned in the answer to this FAQ, states in the Discussion that the concern is the safe operation of the facility. Our question is this: "Is Vermont Yankee required to use the lower administrative limit imposed by the BMO (0.05 uCi/gm I-131 dose equivalent) even though public health and safety is not compromised if this limit is exceeded?" **Response:** No. The intent is when administrative limits are required to ensure 10 CFR Part 100 limits are not exceeded.	Introduced 12/6 2/5/01 – NEI response added. **3/2/01 – Tentative Approval.**	VY

FAQ Log 16

Temp No.	PI	Question/Response	Status	Plant/ Co.
16.5	MS03	**Question:** **Appendix D** NEI 99-02 states (p 26) that Planned Unavailable Hours include "...testing, unless the test configuration is automatically overridden by a valid starting signal, or the function can be promptly restored either by an operator in the control room or by a dedicated operator stationed locally for that purpose." Also,(p 40) The control room operator must be "...an operator independent of other control room operator immediate actions that may also be required. Therefore, an individual must be 'dedicated.'" Ginna Station's Standby Aux Feedwater Pumps do not have an auto-start signal; they are required to be manually started by an operator (not a "dedicated" operator) within 10 minutes. Should this be counted as unavailable time? **Licensee Proposed Response:** Ginna Station should be allowed to use their Tech Spec requirements (manually started within 10 minutes) as guidance for counting Planned Unavailable Hours for the SDAFW pumps during testing, i.e. if the Standby Aux Feedwater Pumps are available by Tech Spec, the PI should not count them as not available.	Introduced 12/6 Discussed. Need to confirm compliance with NUREG 0737	Ginna
16.6	MS01 MS02 MS03 MS04	**Question:** NOTE: This is similar to FAQ Log 15, Temp No. 15.4 NEI 99-02 states (p 26) "Restoration actions must be contained in a written procedure, must be uncomplicated (a single action or a few simple actions), and must not require diagnosis or repair. Credit for a dedicated local operator can be taken only if (s)he is positioned at the proper location throughout the duration of the test for the purpose of restoration of the train should a valid demand occur." Ginna Station Results and Test personnel are qualified to perform valve lineups and are in the control room and/or stationed locally during testing. Do the R&T personnel with the written test procedure meet the guidance of NEI 99-02 for being able to restore equipment to service when needed and thus not counting the testing time as planned unavailable hours? **Licensee Proposed Response:** Yes, provided the plant personnel are qualified and designated to perform the restoration function and are not performing any restoration steps for which they are not qualified, ~~this meets the NEI 99-02 guidance for not counting the testing as planned unavailable hours.~~ Ginna Station considers the restoration steps of the test procedures to be the "written procedure" for the required "restoration actions". The qualified R&T personnel (rather than a dedicated operator) with the test procedures allow Ginna Station to take credit for restoration actions that are virtually certain to be successful during accident conditions while performing tests and thus this time should not count towards Planned Unavailable Hours.	Introduced 12/6 Discussed. Need more information on qualification of R&T tech and actions required **3/2/01 – Response revision. Tentative Approval as revised.**	Ginna
16.10	MS01	**Question:** Turkey Point's Unit 3 Emergency Diesel Generators EDGs) are air-cooled, using very large radiators (eight assemblies, each weighing 300-400 pounds) which form one end of the EDG building. After 12 years of operation the radiators began to exhibit signs of leakage, and the plant decided to replace them. Replacing all eight radiator assemblies is a labor-intensive activity, that requires that sections of the missile shield grating be removed, heat deflecting cowling be cut away, and support structures be built above and around the existing radiators to facilitate the fitup process. This activity could not have been completed within the standard 72 hour allowed outage time (AOT). Last year Turkey Point requested, and received, a license amendment for an extended AOT, specifically for the replacement of these radiators. NEI 99-02 allows for the exclusion of planned overhaul maintenance hours from the EAC performance indicator, but does not define overhaul maintenance. Does an activity as extensive as replacing the majority of the cooling system, for which an extended AOT was granted, qualify as overhaul maintenance? **Licensee Proposed Response:** In this specific case, yes, for three reasons: (1) that activity involves disassembly and reassembly of major portions of the EDG system en toto, tantamount to an overhaul; (2) the activity is infrequent, i.e., the same as the vendor's recommendation for overhaul of the engine alone (every 12 years); and (3) the NRC specifically granted an AOT extension for this activity supported by a quantitative analysis	Introduced 12/6 2/08/01 – Response revised. Tentative Approval as revised. **3/2/01 – Approved. Post 3/2/01.**	Turkey Point

FAQ Log 16

Temp No.	PI	Question/Response	Status	Plant/ Co.
16.11	MS02 MS04	**Question:** At our ocean plant we periodically recirculate the water in our intake structure causing the temperature to rise in order to control marine growth. This process is carried out over a six hour period in which the temperature is raised slowly in order to chase fish toward the fish elevator so they can be removed from the intake and thus minimize the consequential fish kill. Temperature is then reduced and tunnels reversed to start the actual heat treat. Actual time with warm water in the intake is less than half of the evolution. A dedicated operator is stationed for the evolution, and by procedure at any point, can back out and restore normal intake temperatures by pushing a single button to reposition a single circulating water gate. The gate is large and may take several minutes to reposition and clear the intake of the warm water, but a single button with a dedicated operator, in close communication with the control room initiates the gate closure. During this evolution, one train of service water, a support system for HPSI and RHR, is aligned to the opposite unit intake and remains fully Operable in accordance with the Technical Specifications. The second train is aligned to participate in the heat treat, and while functional, has water beyond the temperature required to perform its design function. This design function of the support system is restored with normal intake temperatures by the dedicated operator realigning the gate with a single button if needed. Gate operation is tested before the start of the evolution and restoration actions are virtually certain. The ability of the safety systems HPSI and RHR to actuate and start is not impaired by these evolutions. Does the time required to perform these evolutions on a support system need to be counted as unavailability for HPSI and RHR? **Licensee Proposed Response:** No. As described in the question, the ability of safety systems HPSI and RHR to actuate and start is not impaired by these evolutions. There are no unavailable hours.	Introduced 12/6 12/6 Discussed. HOLD needs more clarity in the question 2/5/01 – need to know design basis	San Onofre
16.13	MS04	**Question:** **Appendix D** NEI 99-02 Revision 0 requires the Residual Heat Removal (RHR) system to satisfy two separate functions: • The ability to take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS • The ability of the RHR system to remove decay heat from the reactor during a normal unit shutdown for refueling or maintenance These functions are completed by the Emergency Core Cooling System on most Westinghouse PWR designs. South Texas Project has a unique design for these functions completed by two separate systems with a shared common heat exchanger. How should unavailability be counted for South Texas Project?~~Since South Texas Project has a unique design for the systems that satisfy the RHR function of the performance indicator, how should unavailability hours be counted for those systems?~~	Introduced 12/6 12/6 Discussed. HOLD needs detailed discussion w/ STP 1/8/01 NEI response revision. 3/1/01 – Sentence added to response. STP request for review completion. **3/2/01 – Tentative Approval as revised.**	South Texas

FAQ Log 16

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: ~~NEI 99-02 Revision 0 requires the Residual Heat Removal (RHR) system to satisfy two separate functions:~~ ~~The ability to take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS~~ ~~The ability of the RHR system to remove decay heat from the reactor during a normal unit shutdown for refueling or maintenance~~ ~~These functions are completed by the Emergency Core Cooling System on most Westinghouse PWR designs. South Texas Project has a unique design for these functions completed by two separate systems with a shared common heat exchanger.~~ Due to the unique design South Texas project, unavailability will be determined as follows: ~~has interpreted the requirements of NEI 99-02 and is applying that interpretation as follows:~~ • In plant Modes 1, 2, 3, and 4 South Texas Project will count the unavailability of the Low Head Safety Injection Pump and the flowpath through it's associated RHR Heat Exchanger as the hours to count for the RHR performance indicator. This equipment and flowpath satisfies the requirement to "take a suction from the containment sump, cool the fluid, and inject at low pressure into the RCS". The RHR pump does not contribute to the performance of this safety function since it can not take suction on the containment sump. • In plant Modes 4, 5, and 6 South Texas Project will count the unavailability hours of the RHR Pump and the flowpath through it's associated RHR Heat Exchanger as the hours to count for the RHR performance indicator. This equipment and flowpath satisfies the requirement to "remove decay heat from the reactor during a normal unit shutdown for refueling or maintenance". The RHR loop is required to be isolated from the Reactor Coolant System in Modes 1, 2, and 3 due to the system design. This requirement prevents the system from performing its intended cooling function until plant pressure and temperature are lowered to a value consistent with the system design. Overlap times when both functions/systems are required will be adjusted to eliminate double counting the same time periods. This position is consistent with the direction published in Frequently Asked Question #149.		

FAQ Log 16

Temp No.	PI	Question/Response	Status	Plant/ Co.
16.14	MS03	**Question:** **Appendix D Question** Davis-Besse has an independent motor-driven feedwater pump (MDFP) that is separate from the two trains of turbine-driven auxiliary feedwater pumps. The piping for the MDFP (when in the auxiliary feedwater mode) is separate from the auxiliary feedwater system up to the steam generator containment isolation valves. The MDFP is not part of the original plant design, as it was added in 1985 following our loss-of-feedwater event to provide "a diverse means of supplying auxiliary feedwater to the steam generators, thus improving the reliability and availability of the auxiliary feedwater system" (quote from the DB Updated Safety Analysis Report). The resolution to FAQ 182 was that Palo Verde should count the unavailability hours for their startup feedwater pump. However, since the DB MDFP (like the Palo Verde startup feedwater pump) is manually initiated, DB has not been reporting unavailability hours for the MDFP due to the exception stated on page 69 of NEI 99-02 Revision 0. The DB MDFP is non-safety related, non-seismic, and is not Class 1E powered or automatically connected to the emergency diesel generators. Based upon discussions with Palo Verde, their startup feedwater pump is Class 1E powered and automatically connected to an EDG. The DB MDFP is required by the Technical Specifications to be operable in modes 1 - 3. However, the Tech Specs do not require the MDFP to be aligned in the auxiliary feedwater mode when below 40 percent power. (The MDFP is used in the main feedwater mode as a startup feedwater pump when less than 40% power). The DB auxiliary feedwater system is designed to automatically feed only an intact steam generator in the event of a steam or feedwater line break. Manual action must be taken to isolate the MDFP from a faulted steam generator. The MDFP is included in the plant PRA, and is classified as high risk-significant for Davis-Besse Per the DB Tech Specs, the MDFP and both trains of turbine-driven auxiliary feedwater pumps are required in Modes 1-3. The MDFP does not fit the NEI definition of either an "installed spare" or a "redundant extra train" per NEI 99-02, Rev. 0, pages 30 - 31. Should the Davis-Besse MDFP be reported as a third train of Auxiliary Feedwater, even though it is manually initiated? (Note: this FAQ is similar to FAQs 205 and 206 submitted by Crystal River regarding the auxiliary feedwater system) **Response:**	Introduced 12/6	Davis-Besse

FAQ Log 17				
Temp No.	**PI**	**Question/Response**	**Status**	**Plant/ Co.**
17.2	PP01	**Question:** For sites that do not use CCTV for primary assessment of the perimeter IDS, how is the Indicator Value for the Protected Area Security Equipment Performance Index calculated? **NRC Response:** For sites that do not use CCTV for primary assessment, as stated in their approved security plan, use only the IDS Unavailability index for the Indicator Value. The Indicator value will be the IDS Unavailability Index divided by one for sites where these conditions exist. The exclusion of the CCTV index from the performance indicator calculation should be indicated by reporting a CCTV normalization factor of zero and zero CCTV compensatory hours for each affected unit. **Alternate Response** Option 1 No change. Option 2 For sites that do not use CCTV for primary assessment, as stated in their approved security plan, use only a weighted IDS Unavailability index for the Indicator Value. The Indicator value will be the IDS Unavailability Index divided by 3/2 for sites where the conditions exist. Option 3 For those sites, the PI will be treated as a unique design. The sites should continue to report compensatory hours and normalization factor, but no indicator value will be calculated.	Introduced 1/10 **1/10/2001 – Tentative Approval – NRC action to confirm acceptability with C. See 2/7/01 – NEI proposed alternate responses.** 3/2/01 – Discussed.	NRC

Temp No.	PI	Question/Response	Status	Plant/ Co.
18.1	MS01 MS02 MS03 MS04	**Question:** Should surveillance testing of the safety system auto actuation system (e.g. Solid State Protection System testing, Engineered Safety Feature testing, Logic System Functional Testing) be considered as unavailable time for all the affected safety systems? During certain surveillance testing an entire train of safety systems may have the automatic feature inhibited.	Introduced 2/8 3/2/01 – Discussed. To be discussed by SSU focus group and NEI task force.	Southern
18.2	MS01 MS02 MS03 MS04	**Question:** When reporting safety system unavailable time there are periodic (such as weekly) evolutions that although they may not be simple actions to restore a safety system, they result in the safety system being unavailable for no more than several minutes. Is this level of tracking unavailable time required?	Introduced 2/8 3/2/01 – Discussed. To be discussed by SSU focus group and NEI task force.	Southern
18.3	MS04	**Question:** If a plant is allowed by its Tech Specs, to secure an operating Shut Down Cooling (SDC) train and not enter a LCO action statement, are they required to incur SDC train unavailability for the purposes of the RHR indicator, when the SDC train is taken out of service? **Licensee Proposed Response:** No. A SDC train "is required" as specified in the plant's Tech. Specs. If the plant is not in a SDC LCO action statement, then no SDC (RHR) unavailability is incurred.	Introduced 2/8 Methodology for CE plants RHR needs to be reviewed Discussed. 3/2/01 – NEI action to obtain additional information	Calvert Cliffs
18.4	MS04	**Question:** With our unit shutdown, in Mode 6 with water level in the refuel pool greater than 23 feet above the top of the fuel assemblies seated in the reactor vessel, only one SDC loop is required to be operable and in operation by our Tech. Specs. While in this plant condition, may the operable SDC loop be replaced with an alternate NRC approved means of decay heat removal without incurring SDC (RHR) unavailability?	Introduced 2/8 Methodology for CE plants RHR needs to be reviewed Discussed. 3/2/01 – NEI action to obtain additional information	Calvert Cliffs

Temp No.	PI	Question/Response	Status	Plant/ Co.
18.5	IE02	**Question:** Should the reactor trip described in the scenario below be included as a "Scram with Loss of Normal Heat Removal?" A very heavy rainfall caused the turbine building gutters to overflow and water entered the interior of the turbine building. Water subsequently leaked onto the main feedwater pump B area and affected the pump speed control circuitry. Feedwater pump B speed increased and feedwater pump A speed decreased to compensate. Shortly thereafter feedwater pump B speed decreased and feedwater pump A increased. The control room operators placed the feedwater pump turbine master speed controller in manual in an attempt to recover from the transient. This action stabilized pump speed. The transient caused the digital feedwater control system to place the feedwater regulating valves in manual control. Levels in steam generators B, C, and D began to rise. A hi-hi steam generator level (P-14) occurred in steam generator B. The P-14 signal tripped both main feedwater pumps, generated a feedwater isolation signal, and tripped the main turbine. The reactor tripped upon turbine trip. Main feedwater pumps tripped on the P-14 signal as part of the plant design. Feedwater pump B had malfunctioned; however, feedwater pump A remained available. Auxiliary feedwater system automatic starts occurred for motor driven pumps A and B as well as the turbine driven auxiliary feedwater pump (all of these responses were as designed). **Response:** No, because the MFW system was readily restorable to perform its post trip cooldown function	Introduced 2/8 **3/2/01 – Tentative Approval**	Catawba
18.6	IE03	**Question:** An unscheduled power reduction was commenced to clean main condensed water boxes. This decision was a result of indications of condenser fouling. Concurrent with this condition was the plant entry into Abnormal Operating Procedure "High Winds, Hurricanes, and Tornadoes" due to sustained winds of > 60 MPH. This resulted in rough Lake Ontario conditions. The lake agitation created high levels of suspended crud (silt) which was drawn into the Circ. Water System (evidenced by Condenser fouling indications). In response to the safety concerns arising from the external events, and minimize the impact of these events on plant operational conditions, a power reduction was taken to clean and restore normal condenser operation. Actual power change was not predictable 72 hours in advance. The anticipatory power reduction was intended to reduce the impact of external events (high winds creating unsettled lake conditions resulting in silt intrusion) on plant operational conditions. Should this downpower be included as a unplanned power change? **Response:**	Introduced 2/8 Need more information	FitzPatrick
18.7	MS01 MS02 MS03 MS04	**Question:** ~~The Mitigating Systems Performance Indicators allow for operator action to restore a system without incurring a penalty while performing system tests. Can the same criteria be applied to Safety System Unavailability in non-test circumstances if the affected system(s) can be promptly restored either by an operator in the control room or qualified plant personnel remote from the control room, provided there is a means of communication with the Control Room?~~ **Response** ~~No. The mitigating system PI only allows for operator action for simple actions when the system is in test and must not require diagnosis or repair.~~	**Introduced 2/8/01. Discussed. Tentative Approval. 3/2/01 – Withdrawn.**	Prairie Island

Temp No.	PI	Question/Response	Status	Plant/ Co.
19.1	IE03	**Question:** If a plant chooses to correct a deficiency less than 72 hours following discovery (a steam leak or other condition) and reduces plant power to limit radiation exposure (ALARA) and this reduction in power (>20%) is not required by the license bases would this reduction be counted? **Response:**	Introduced 3/1	River Bend
19.2	MS01 MS02 MS03 MS04	**Question:** Page 4 of NEI 99-02 states: "The guidance provided in Revision 0 to NEI 99-02 is to be applied on a forward fit basis…", however there is also a provision to reset fault exposure hours (page 29) that requires 4 quarters have elapsed since discovery. If reset of fault exposure is applied to historical data submitted under the "best effort" collection method (i.e. grandfathered data previously collected under INPO 98-005 guidelines), does this constitute a backfit of the NEI 99-02 guidance? Additionally, if the reset of fault exposure hours does constitute a backfit, would the station then be required to revise all of the historical data to conform with all 99-02 requirements? **Response:**	Introduced 3/1	Susquehanna
19.3	MS04	**Question:** **(Potential Appendix D question – Question being reworded)** Analysis has shown that when RHR is operated in the Suppression Pool Cooling (SPC) Mode, the potential for a waterhammer in the RHR piping exists for design basis accident conditions of LOCA with simultaneous LOOP. SPC is used during normal plant operation to control suppression pool temperature within Tech Spec requirements, and for quarterly Tech Spec surveillance testing. We do not enter an LCO when SPC mode is used for routine suppression pool temperature control or surveillance testing because the frequency of operation is minimal, and total run time is limited under administrative controls. If the specified design basis accident scenario occurs while the RHR system is in SPC mode, there is a potential for collateral equipment damage that could subsequently affect the ability of the system to perform the safety function. If the time RHR is run in SPC mode must be counted as unavailability, then our station RHR system indicator will be forever white due to the number of hours of normal SPC run time (approximately 300 hours per year). This would tend to mask any other problems, which would not be visible until the indicator turned yellow at 5.0%. Should our station count unavailability for the time when RHR is operated in SPC mode for temperature control or surveillance testing? **Response:**	Introduced 3/1	Susquehanna

Temp No.	PI	Question/Response	Status	Plant/ Co.
19.4	IE03	**Question:** The hydrogen cooler for the main generator began leaking at an increased rate above normal IP-3 historical trends but well within limits requiring a shutdown and with limited potential with that rate to cause gas binding in the hydrogen cooler heat exchanger that could result in a high delta temperature trip of the generator. For the degraded condition which has been seen in the past and repaired, an action plan was developed, work packages prepared, materials procured, a monitoring program established and an administrative limit established at which a decision would be taken to correct the condition including heat exchanger replacement. Approximately December 15, 2000, there was a step increase in the hydrogen leak rate although still below the administrative limit but approaching it. Because of the upcoming holidays, management decided adequate resources may not be available if the leak were to increase further so it was decided to shut the plant down and replace the hydrogen cooler heat exchangers. This decision and the subsequent necessary actions was less than the 72 hour criteria of the guidance in NEI-99-02 (12/15 - 12/18). IP-3's concluded based on the NEI-99-02 guidance for PI IE03, specifically at FAQ # 6 that the event and IP-3's preparation met that criterion so the shutdown was not counted Does this event count? **Response:**	Introduced 3/1	IP3

Temp No.	PI	Question/Response	Status	Plant/ Co.
19.5	MS01	**Question:** NEI 99-02, Revision 0, page 48, line 1 (Clarifying Notes) states: "When determining fault exposure hours for the failure of an EDG to load-run following a successful start, the last successful operation or test is the previous successful load-run (not just a successful start). To be considered a successful load-run operation or test, an EDG load-run attempt must have followed a successful start and satisfied one of the following criteria: • a load run of any duration that resulted from a real (e.g., not a test) manual or automatic start signal • a load-run test that successfully satisfied the plant's load and duration test specifications • other operation (e.g., special tests) in which the emergency diesel generator was run for at least one hour with at least 50% of design load When an EDG fails to satisfy the 12/18/24- month 24-hour duration surveillance test, the faulted hours are computed based on the last known satisfactory load test of the diesel generator as defined in the three bullets above." This may be in conflict, however, with the following sentence, which states: "For example, if the EDG is shutdown during a surveillance test because of a failure that would prevent the EDG from satisfying the surveillance criteria, the fault exposure unavailable hours would be computed based upon the time of the last surveillance test that would have exposed the discovered fault." If a 24-hour duration surveillance test revealed a failure due to a cause that pre-existed during the entire 12/18/24 month operating cycle, then it is not clear whether fault exposure should be calculated based on the guidance in the three listed criteria, or the three listed criteria are totally disregarded if the failure was not revealed until the 24-hour duration surveillance test. This is particularly unclear for a condition that could have been revealed during any test (e.g., any monthly 1-hour load-run surveillance), but actually happened during the 24-hour duration surveillance test. **Licensee Proposed Response:** The three listed criteria are correct and appropriate for determining fault exposure unavailable hours. The 24-hour duration surveillance test is a performance test. There is no regulatory basis (unless discussed in an individual plant's FSAR) that an EDG be capable of functioning for 24 continuous hours. Nor is there any risk informed basis that an EDG must be capable of functioning for 24 continuous hours, as a loss of an offsite electric power system would probably be restored within the one-hour period (82% probability for Palo Verde during power operation) discussed in the three listed criteria and EDGs are typically redundant equipment.	Introduced 3/1 3/2/01 – Discussed. NEI action to revise to clarify question and proposed resonse.	APSC

Temp No.	PI	Question/Response	Status	Plant/ Co.
19.6	MS01 MS02 MS03 MS04	**Question:** **(Potential Appendix D Question)** At Prairie Island the three safeguards Cooling Water (service water) pumps, two for operation (one is a swing pump), were declared inoperable for lack of qualified source of lineshaft bearing water. There were two sources of water to the lineshaft bearings: a non-safeguards well water supply (preferred, because it supplied cleaner water) and the Filtered Water supply off the cooling Water system (standby source, starts automatically on low pressure). The Filtered Water system was originally designated as safety-related but had been downgraded in 1977 and subsequent modifications did not maintain the original quality level. Also, the original design and installation of the Filtered Water system failed to provide safety related electrical power for the Filtered Water strainer backwash system. During a Loss Of Offsite Power (LOOP), this could have resulted in clogging of the Filtered Water strainers and subsequent loss of Filtered Water to the lineshaft bearings, making the cooling water pumps inoperable. The plant declared all three safeguards Cooling Water pumps inoperable and entered into Technical Specifications 3.0.c (motherhood). Compensatory measures were implemented to ensure continued availability of water to the lineshaft bearings. The plant requested a Notification of Enforcement Discretion (NOED) that allowed continued operation of both units until installation of a temporary modification to provide qualified Filtered Water supply to two of the three pumps was completed (14 days). Two initiating events were identified that could result in the loss of bearing water and unavailability of the cooling water pumps (seismic and LOOP) were discussed during the NOED request. The plant concluded that the risk of continued operation during the 14 day NOED period (compared to the risk of a two unit shutdown – where Cooling water would still have been required for decay heat removal) was low, based on the low likelihood of risk-significant initiating events, the equipment remained available to protect the decay heat removal safety function had an event occurred, the compensatory measures put in place, and the limited time over which the condition existed. The NRC accepted this safety rationale, combined with the compensatory actions as an adequate basis, and granted the NOED. The Cooling Water System is a support system and it's unavailability affects: High Pressure Safety Injection, Auxiliary Feedwater, Residual Heat Removal, and Unit 1 Emergency AC (Unit 2 Emergency AC is cooled independent of Cooling Water). Prairie Island included the time that the Cooling Water Pumps were declared inoperable, approximately 300 hours, as unplanned unavailability. This resulted in two White Indicators (one on each unit). Two other systems (one per unit) are on the Green/White threshold, and two others (again, one per unit) are Green, but close to the Green/White threshold. Depending on the number of unavailable hours in future quarters, and since these indicators are 12 quarter averages, the indicators on or near the threshold may change from Green to White and back again. Should the time from implementation of compensatory measures to completion of the temporary modification be counted as safety system unavailability? **Response:** •	Introduced 3/1	Prairie Island
19.7	PP01	**Question:** **Proposed Replacement for FAQ 250** If a new Intrusion Detection System (IDS) or Closed Circuit Television (CCTV) design change package has been prepared by Engineering and funding for the new upgrade has been approved by management but the physical installation will not occur immediately, when does the NEI 99-02 "Scheduled equipment upgrade" exemption occur to stop counting the compensatory hours?	Introduced 3/2 **3/2/01 – Approved. Post 3/2/01.**	

Temp No.	PI	Question/Response	Status	Plant/ Co.
		Response: In the situation where system degradation results in a condition that cannot be corrected under the normal maintenance program (e.g., engineering evaluation specified the need for a system/component modification or upgrade), and the system requires compensatory posting, the compensatory hours stop being counted toward the PI for those conditions addressed within the scope of the modification after such an evaluation has been made and the station has formally initiated a commitment in writing with descriptive information about the upgrade plan including scope of the project, anticipated schedule, and expected expenditures. This formally initiated upgrade is the result of established work practices to design fund, procure, install and test the project. A note should be made in the comment section of the PI submittal that the compensatory hours are being excluded under this provision. Compensatory hour counting resumes when the upgrade is complete and operating as intended by site requirements for sign-off. Reasonableness should be applied with respect to a justifiable length of time the compensatory hours are excluded from the PI.		