REACTOR OVERSIGHT PROCESS (ROP)
MONTHLY PUBLIC MEETING AGENDA

April 21, 2010; 8:30 AM – 12:30 PM; Residence Inn Bethesda Hotel;
Montgomery 1 & 2 Conference Room

8:30 – 8:35 AM	Introduction and Purpose of Meeting
8:35 – 9:00 AM	Performance Assessment Branch Topics 1. General topics of interest in the performance assessment area 2. Opportunity for public comment
9:00 – 9:25 AM	Reactor Inspection Branch Topics 1. General topics of interest in the inspection area 2. Opportunity for public comment
9:25 – 9:30 AM	Break
9:30 – 10:30 AM	Discussion of Performance Indicator (PI) Topics 1. Potential NEI 99-02 guidance changes • MSPI EDG component boundary • MSPI EDG failure mode definitions • MSPI basis document updates 2. Opportunity for public comment
10:45 – 11:00 AM	Break
11:00 AM – 12:15 PM	Discussion of Open and New PI Frequently Asked Questions (FAQs) *Note: Topic may be moved up if meeting is ahead of schedule. The latest draft FAQs is located on the public web at: http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/draft_faqs.pdf. This list is subject to change the day before the meeting based on availability of new draft FAQs provided by the Nuclear Energy Institute. Public comments will be addressed on FAQs following the discussion.*
12:15 – 12:30 PM	Future Meeting Dates, Action Items, Future Agenda Topics

as an Apparent Violation (AV), if a violation is involved, or as a Finding (FIN) to-be-determined (TBD) if no violation is being considered.

03.34 Present Performance. The Enforcement Policy and the Enforcement Manual consider enforcement discretion for violations involving old design issues based, in part, on whether the violations were caused by conduct linked to present performance. Violations that are at least 3 years old and meet certain other conditions are normally not considered to be reflective of present performance. Following the above precedent, present performance is used in Appendix B, 'Issue Screening,' of this IMC to describe those performance characteristics described by (or associated with) a potential CCA that occurred within the past 3 years.

03.35 Red Finding. A finding of high safety significance as determined by IMC 0609, 'Significance Determination Process.'

03.36 Requirement. As used in the context of this IMC, requirement means a legally binding obligation such as a statute, regulation, license condition, technical specification, or order that is enforceable by the NRC. In this context, statutes and regulations that are not enforceable by the NRC are not requirements although they may trigger licensees to establish standards or self-imposed standards.

03.37 Safety-Conscious Work Environment (SCWE). An environment in which employees feel free to raise safety concerns, both to their management and to the NRC, without fear of retaliation and where such concerns are promptly reviewed, given the proper priority based on their potential safety significance, and appropriately resolved with timely feedback to employees.

03.38 Standard or Self-Imposed Standard. As used on the context of this IMC and in Appendix B, 'Issue Screening,' of this IMC, a standard is a licensee-established expectation that does not constitute a requirement, as defined above. Licensees establish standards in a variety of ways. Paragraph 5, 'Performance Deficiency Basis,' of IMC 0308 Attachment 3, 'Significance Determination Process Basis Document,' establishes that, in order to identify a performance deficiency, staff must make a reasonable determination that the licensee intended to meet some requirement or standard and they did not, having had the opportunity to do so. Industry Codes and Standards, unless adopted by the licensee or incorporated into a requirement, do not constitute an independent basis for a performance deficiency. The determination of an unmet standard requires application of experience, training, and judgment, in the context of the above guidance.

03.39 Self-Revealing. For the purpose of screening and documentation in the ROP, self-revealing findings are those findings developed from issues that become self-evident and require no active and deliberate observation by the licensee or NRC inspectors to determine whether a change in process or equipment capability or function has occurred. Self-revealing issues become readily apparent to either NRC or licensee personnel through a readily detectable degradation in the material condition, capability, or functionality of equipment or plant operations and require minimal analysis to detect. Self-revealing findings are derived from self-revealing issues and are treated similarly to NRC-identified findings for the purposes of screening and documentation.

Examples of self-revealing issues include those revealed through: reactor trips and secondary plant transients; failure of emergency equipment to operate; unanticipated or unplanned relief valve actuations; obvious failures of fluid piping or plant equipment; identification of large quantities of water in areas where you would not normally expect such a condition; and non-compliance with high radiation area requirements that, in some cases, was identified through an electronic dosimeter alarm.

03.40 Sensitive Unclassified Non-Safeguards Information (SUNSI). Means any information of which the loss, misuse, modification, or unauthorized access can reasonably be foreseen to harm the public interest, the commercial or financial interests of the entity or individual to whom the information pertains, the conduct of NRC and Federal programs, or the personal privacy of individuals. The NRC policy for handling, marking, and protecting SUNSI is available on the NRC Public Web site at http://www.nrc.gov/reading-rm/doc-collections/commission/comm-secy/2005/2005-0054comscy-attachment2.pdf. Additional staff guidance for handling of SUNSI is published on the NRC internal WEB site.

03.41 Severity Levels. Are used (1) to indicate significance of a violation evaluated under TE; and (2) to determine the appropriate enforcement action to be taken.

03.42 Significant or Significance. The significance of a finding, in the context of this IMC, is a measure of the finding's safety or security impact as determined by IMC 0609, 'Significance Determination Process.'

The phrase 'no findings of significance,' was formerly used in power reactor inspection reports, to mean 'no performance deficiencies of more-than-minor significance were identified' in accordance with the screening process described in Appendix B, 'Issue Screening'. The phrase 'no findings of significance' has been replaced with 'no findings.'

03.43 Significance and Enforcement Review Panel (SERP). A designated panel of NRC personnel that provides a management review of the preliminary significance characterization and basis of findings that are potentially Greater than Green. No official agency preliminary significance determination of White, Yellow, Red, or greater than Green will be made without a SERP review. Additional insights are provided in Inspection Manual Chapter 0609 Attachment 1, 'Significance and Enforcement Review Panel Process.'

03.44 Significance Determination Process (SDP). The process described in IMC 0609, 'Significance Determination Process,' and associated appendices that is applied to an inspection finding to determine its safety or security significance as either Green (very low), White (low-to-moderate), Yellow (substantial), or Red (high).

03.45 To Be Determined (TBD). The inspection report characterization that is required by IMC 0609, 'Significance Determination Process,' if the staff's significance determination of a finding is not complete at the time of issuance of the inspection report, and not reviewed by the SERP. Final significance determination should be completed within 90 days from the issue date of the first official correspondence that describes a finding as TBD.

03.46 Traditional Enforcement (TE). The enforcement approach in which the significance of violations is reflected by a severity level (SL) ranging from the lowest, SL-IV, to the

FAQs for ROP Meeting with NRC April 21, 2010

No.	PI	Topic	Status	Plant/Co.	Point of Contact
09-06	EP01	Offsite Call Simulation	Tentative approval at 3/18 mtg. NRC (Kahler) now ready to approve as revised by NEI 4/12/10.	DAEC	Mike Davis, Bob Murrell, Marty Hug
09-09	IE03	Unplanned Power Changes	Approved 3/18 Mtg	Generic	Duke, Jeff Thomas
09-10	EP02	Common EOF	On Hold for EP Task Force after 3/18 mtg.	Generic	Tony Feltman, Marty Hug
10-01	None	Withdrawal of FAQs	Approved 3/18 mtg	Generic	PGN, Ken Heffner
10-02	IE04	USwC	Introduced at 3/18 mtg	Generic	PGN, Ken Heffner
10-03	IE04	USwC	Introduced at 3/18 mtg	Wolf Creek	WCNOC, T. Damashek
New 10-04	MSPI	Missing CCF Value	New @ 4/21 mtg	BFN1	TVA, Rod Miller
New 10-05	IE04	USwC – LOFC EOP	New @ 4/21 mtg	Generic	APS, Mark McGhee, Del Elkinton

FAQ 09-06

Plant:	Duane Arnold Energy Center
Date of Event:	6/24/09
Submittal Date:	7/21/09
Licensee Contact:	Mike Davis, Bob Murrell
Tel/email:	319-851-7032/ michael.davis@nexteraenergy.com
	319-851-7900/ robert.murrell@nexteraenergy.com
NRC Contact:	Randy Baker Tel/email: 319-851-7210

Performance Indicator: **Drill and Exercise Performance**

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective 2 months after final approval to allow the current cycle of Licensed Operator Requalification Training (LORT) to continue without disruption.

Question Section

NEI 99-02 Guidance needing interpretation (include page and line citation):

NEI 99-02, Rev. 6 page 45, lines 43 – 46:

> *Performance statistics from operating shift simulator training evaluations may be included in this indicator only when the scope requires classification. Classification, PAR notifications and PARs may be included in this indicator if they are performed to the point of filling out the appropriate forms and demonstrating sufficient knowledge to perform the actual notification.*

NEI 99-02, Rev. 6 page 46, lines 17 – 19:

> *Simulation of notification to offsite agencies is allowed. It is not expected that State/local agencies be available to support all drills conducted by licensees. The drill should reasonably simulate the contact and the participants should demonstrate their ability to use the equipment.*

Event or circumstances requiring guidance interpretation:

In accordance with Duane Arnold Energy Center (DAEC) procedures for making offsite notifications of emergency events, the Shift Technical Advisor (Key Communicator) fills out the notification form, gains approval from the Shift Manager (Key Decision Maker/Emergency Director), and hands the form off to the Security Shift Supervisor (not filling an NRC Participation PI key position). The Security Shift Supervisor then contacts offsite authorities using a telephone system (one call notifies all county and state authorities).

During licensed operator continuing training simulator evaluations, Security personnel are sometimes not available to participate. In these cases, the simulator instructor/evaluator role-plays as the Security Shift Supervisor. When this occurs, the instructor does not pick up the phone and simulate making a call to offsite authorities.

The NRC resident has challenged counting these as successful DEP opportunities because there is no demonstration of using the phone equipment.

NEI 99-02, Rev. 6 seems to differentiate the extent of demonstrating notification between operations simulator evaluations and drills. This is also discussed in a previous FAQ 202.

What extent of simulation is required to "demonstrate sufficient knowledge to perform actual notification"? Should "demonstration of their ability to use the equipment" be applied to operations simulator evaluations?

In the simulator evaluations in question, the simulator scenario was developed to have the instructor role-play as the Shift Security Supervisor and did not require any participant to demonstrate use of the phone if security personnel were not available. If these instances do not meet the intent for demonstrating sufficient knowledge of performing notifications and there were no errors made by the participants, should these opportunities be counted in the performance indicator as failures?

If licensee and NRC resident/region do not agree on the facts and circumstances explain

The NRC has concluded that the opportunities are failures due to not demonstrating the use of phone equipment.

Potentially relevant existing FAQ numbers

None

<u>Response Section</u>

Proposed Resolution of FAQ

During operator simulator training, personnel filling a non-key position for making a phone call to offsite agencies may not be available. In these instances where the Shift Manager (Emergency Director) and the Shift

Communicator do not perform the notification phone call, it is acceptable to demonstrate the notification process up to the point of filling out the appropriate forms and providing the completed notification forms to a person role-playing as the phone-talker.

At a later time an off sequence phone talker will complete the process of using the telecommunications equipment.

Past opportunities performed by Licensees in a similar manner as the FAQ submitter will not require revision. Data will be collected using this new process going forward from the effective date of this FAQ.

The following additional clarifying information is provided to ensure consistent implementation of the proposed rewording of guidance added to NEI 99-02, Rev. 6 page 45, lines 43 – 46:

- What happens if an inspector identifies a licensee did not demonstrate the use of communications equipment and procedures for evaluation associated with a particular simulator session? If an inspector identifies a classification/notification performance, which was counted in the PI data, which did not include a demonstration of the communications equipment that performance is to be removed from the DEP PI calculation. The performance would not be considered a success or failure.

- Can one out-of-sequence phone talker activity evaluation be tied to multiple in-simulator classification / notification performances, or is a one-to-one correspondence required? A one-to-one out-of-sequence phone talker activity evaluation correspondence is required for each classification / notification performance.

- Does the out-of-sequence activity have to take place within any specified time period? Yes, the out-of-sequence communicator evaluation must be completed during the quarter the classification/notification was made.

- Will licensees be required to identify which out-of-sequence communicator evaluation(s) was/were connected to which in-simulator performance(s)? Yes. In order to evaluate the timeliness aspect of the DEP Notification opportunity, the documentation needs to be clear for each Notification opportunity as to how long the Notification process took:
    - In the Simulator and,
    - How long it took the phone talker to complete the same notification by use of the communications equipment to contact the first offsite stakeholder.

The licensee needs to provide sufficient documentation to enable an inspector to arrive at the same conclusion the licensees did concerning timeliness of the Notification.

- Performance opportunities for the Out-of-sequence phone talker activities are expected, to the extent reasonable, to be made available to all qualified ERO phone talkers and performed by most of the qualified individuals. However, there is no intent by this FAQ to track phone talkers for participation purposes.

If appropriate, provide proposed rewording of guidance for inclusion in next revision.

NEI 99-02, Rev. 6 page 45, lines 43 – 46:

Current wording is italicized, proposed additions are underlined.

Performance statistics from operating shift simulator training evaluations may be included in this indicator only when the scope requires classification. Classification, PAR notifications and PARs may be included in this indicator if they are performed to the point of filling out the appropriate forms and demonstrating sufficient knowledge to perform the actual notification.
Note: "demonstrating sufficient knowledge" is defined as demonstrating the use of communications equipment to contact the first offsite stakeholder for the purpose of transmitting initial notification information (offsite stakeholder maybe role-played) in accordance with site communication procedure(s), as well as, if used, demonstration of the needed interface between the key ERO communicator and the phone-talker. It is recognized that key control room positions may not perform the actual communication with offsite agencies as part of the notification process. Personnel filling non-key positions for contacting offsite agencies (phone-talker) may not be available during simulator training. If an evaluator role-plays the phone-talker during the simulator session, a phone-talker is required to complete the notification process out of sequence (e.g. notification form completed in the simulator is provided to a phone-talker at a later time and the phone-talker demonstrates use of the telephone equipment to an evaluator). Interactions normally between the Key Communicator and the phone-talker (e.g. receiving instruction, discussion of the notification and correction of errors in the notification form) occur between the phone-talker and an evaluator role playing the Key Communicator for this off sequence demonstration. Timeliness is determined by adding the time required to complete the notification form in the simulator to the time required by the phone-talker to interact and then utilize the communications equipment out of sequence.

[Continue with page 45, Line 47, "However, there is no intent to disrupt ongoing operator qualification programs..."]

Plant: N/A
Date of Event: N/A
Submittal Date: October 15, 2009
Licensee Contact: Jeff Thomas, 704-382-3438, cjthomas@duke-energy.com
NRC Contact: John Thompson, 301 415-1011, john.thompson@nrc.gov

UNPLANNED POWER CHANGES PER 7,000 CRITICAL HOURS

Purpose

This indicator monitors the number of unplanned power changes (excluding scrams) that could have, under other plant conditions, challenged safety functions. It may provide leading indication of risk-significant events but is not itself risk-significant. The indicator measures the number of plant power changes for a typical year of operation at power.

Indicator Definition

The number of unplanned changes in reactor power greater than 20% of full-power, per 7,000 hours of critical operation excluding manual and automatic scrams.

Data Reporting Elements

The following data is reported for each reactor unit:

- the number of unplanned power changes, excluding scrams, during the previous quarter
- the number of hours of critical operation in the previous quarter

Calculation

The indicator is determined using the values reported for the previous 4 quarters as follows:

$$value = \frac{(total\ number\ of\ unplanned\ power\ changes\ over\ the\ previous\ 4\ qtrs)}{total\ number\ of\ hours\ critical\ during\ the\ previous\ 4\ qtrs} x\ 7{,}000\ hrs$$

Definition of Terms

Unplanned ~~change~~ change in reactor power, for the purposes of this indicator, is a change in reactor power that (1) ~~was~~ was initiated less than 72 hours following the discovery of an off-normal condition that required or ~~resulted~~ resulted in a power change of greater than 20% full power to resolve and (2) has not been excluded ~~from~~ from counting per the guidance below. Unplanned changes in reactor power also include uncontrolled excursions of greater than 20% of full power that occur in response to changes in reactor or plant conditions and are not an expected part of a planned evolution or test.

Clarifying Notes

The value of 7,000 hours is used because it represents one year of reactor operation at about an 80% availability factor.

If there are fewer than 2,400 critical hours in the previous four quarters the indicator value is displayed as N/A because rate indicators can produce misleadingly high values when the denominator is small. The data elements (unplanned power changes and critical hours) are still reported.

The 72 hour period between discovery of an off-normal condition and the corresponding change ~~in power level of greater than 20% of full power to resolve and the corresponding change~~ in power level is based on the typical time to assess ~~prepare for a planned power change. It includes time to assess~~ the plant condition, and prepare, review, and approve the necessary work orders, procedures, and necessary safety reviews, to effect a repair. The key element to be used in determining whether a power change should be counted as part of this indicator is the 72-hour period and not the extent of the planning that is performed between the discovery of the condition and initiation of the power change.

~~recognizing the possible need for a change in power level of greater than 20% and completion of the power change. The licensee should have objective evidence to demonstrate when the possible need for the downpower was recognized such as logs documenting actions required by Technical Specifications, troubleshooting plans, meeting minutes, corrective action program entries, or similar type documentation.~~

Given the above, it is incumbent upon licensees to provide objective evidence that identifies when the off-normal condition was discovered and when the power change of more than 20% was initiated. Such objective evidence may include logs, troubleshooting plans, meeting minutes, corrective action program documents, or similar type documentation.

Examples of occurrences that would be counted against this indicator include:

- Power reductions that exceed 20% of full power and are not part of a planned and documented evolution or test. Such power changes may include those conducted in response to equipment failures or personnel errors or those conducted to perform maintenance.
- Runbacks and power oscillations greater than 20 % of full power. A power oscillation that results in an unplanned power decrease of greater than 20% followed by an unplanned power increase of 20% should be counted as two separate PI events, unless the power restoration is implemented using approved procedures. For example, an operator mistakenly opens a breaker causing a recirculation flow decrease and a decrease in power of greater than 20%. The operator, hearing an alarm, suspects it was caused by his action and closes the breaker resulting in a power increase of greater than 20%. Both transients would count since they were the result of two separate errors (or unplanned/non-proceduralized action).
- Unplanned downpowers of greater than 20% of full power for ALARA reasons

Examples of occurrences that are <u>not</u> counted include the following:

- Planned power reductions (anticipated and contingency) that exceed 20% of full power and are initiated in response to an off-normal condition discovered at least 72 hours before initiation of the power change.
- Unanticipated equipment problems that are encountered and repaired during a planned power reduction greater than 20% that alone could have required a power reduction of 20% or more to repair.
- Apparent power changes that are determined to be caused by instrument problems.
- If conditions arise that would normally require unit shutdown, and an NOED is granted that allows continued operation before power is reduced greater than 20%, an unplanned power

change is not reported because no actual change in power greater than 20% of full power occurred. However, a comment should be made that the NRC had granted an NOED during the quarter, which, if not granted, may have resulted in an unplanned power change.

- Anticipatory power reductions intended to reduce the impact of external events such as hurricanes or range fires threatening offsite power transmission lines, and power changes requested by the steam load dispatches.
- Power changes to make rod pattern adjustments
- Power changes directed by the load dispatcher under normal operating conditions due to load demand, for economic reasons, for grid stability, or for nuclear plant safety concerns.

Anticipated power changes greater than 20% in response to expected environmental problems (such as accumulation of marine debris, biological contaminants, or frazil icing) which are proceduralized but cannot be predicted greater than 72 hours in advance may not need to be counted unless they are reactive to the sudden discovery of off-normal conditions. However, unique environmental conditions which have not been previously experienced and could not have been anticipated and mitigated by procedure or plant modification, may not count, even if they are reactive. The licensee is expected to take reasonable steps to prevent intrusion of marine or other biological growth from causing power reductions. Intrusion events that can be anticipated as part of a maintenance activity or as part of a predictable cyclic behavior would normally be counted unless the down power was planned 72 hours in advance. The circumstances of each situation are different and should be identified to the NRC in a FAQ so that a determination can be made concerning whether the power change should be counted.

Licensees should use the power indication that is used to control the plant to determine if a change of greater than 20% of full power has occurred.

If a condition is identified that is slowly degrading and the licensee prepares plans to reduce power when the condition reaches a predefined limit, and 72 hours have elapsed since the condition was first identified, the power change does not count. If however, the condition suddenly degrades beyond the predefined limits and requires rapid response, this situation would count. If the licensee has previously identified a slowly degraded off-normal condition but has not prepared plans recognizing the potential need to reduce power when the condition reaches predefined limits, then a sudden degradation of that condition requiring rapid response would constitute a new off-normal condition and therefore, a new time of discovery.

Off -normal conditions that begin with one or more power reductions and end with an unplanned reactor trip are counted in the unplanned reactor scram indicator only. However, if the cause of the downpower(s) and the scram are different, an unplanned power change and an unplanned scram must both be counted. For example, an unplanned power reduction is made to take the turbine generator off line while remaining critical to repair a component. However, when the generator is taken off line, vacuum drops rapidly due to a separate problem and a scram occurs. In this case, both an unplanned power change and an unplanned scram would be counted. If an off-normal condition occurs above 20% power, and the plant is shutdown by a planned reactor trip using normal operating procedures, only an unplanned power change is counted.

FAQ 09-10

FAQ TEMPLATE

Plant: Plant Generic

Date of Event:	10/19/2009		
Submittal Date:	11/09/2009		
Licensee Contact:	Tony Feltman Martin Hug	Tel/email:	ahfeltman@tva.gov mth@nei.org
NRC Contact:		Tel/email:	

Performance Indicator: NEI 99-02 (rev. 6) 2.4 Emergency Preparedness Cornerstone Emergency Response Organization Drill Participation

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective when approved.

Question Section

NEI 99-02 Guidance needing interpretation (include page and line citation):

Page 50, Lines 3-8

Purpose

This indicator tracks the participation of ERO members assigned to fill Key Positions in performance enhancing experiences, and through linkage to the DEP indicator ensures that the risk significant aspects of classification, notification, and PAR development are evaluated and included in the PI process. This indicator measures the percentage of ERO members assigned to fill Key Positions who have participated recently in **performance-enhancing experiences** such as drills, exercises, or in an actual event.

Page 50, Lines 10 - 13
Indicator Definition
The percentage of ERO members assigned to fill Key Positions that have participated in a drill, exercise, or actual event during the previous eight quarters, **as measured on the last calendar day of the quarter.**

Page 50, Lines 13 - 14
If an ERO member filling a Key Position has participated in more than one drill during the eight quarter evaluation period, the most recent participation should be used in the indicator statistics.

Page 52, Lines 20-22
If a person is assigned to more than one Key Position, it is expected that the person be counted in the denominator for each position and in the numerator only for drill participation that addresses each position. **Where the skill set is similar**, a single drill might be counted as participation in both positions.

Page 52, Lines 24-29
Assigning a single member to multiple Key Positions and then only counting the performance for one Key Position could mask the ability or proficiency of the remaining Key Positions. The concern is that an ERO member having multiple Key Positions may never have a performance enhancing experience for all of them, yet credit for participation will be given when any one of the multiple Key Positions is performed; particularly, if more than one ERO position is assigned to perform the same Key Position.

Page 52, Lines 31-41
ERO participation should be counted for each Key Position, **even when** multiple Key Positions are assigned to the same ERO member. In the case where a utility has assigned two or more Key Positions to a single ERO member, each Key Position must be counted in the denominator for that ERO member and credit given in the numerator when the ERO member performs each Key Position.

Similarly, ERO members **need not individually** perform an opportunity of classification, notification, or PAR development in order to receive ERO Drill Participation credit. The evaluation of the DEP opportunities is a crew evaluation for the entire Emergency Response Organization. ERO members may receive credit for the drill if their participation is a meaningful opportunity to gain proficiency in their ERO function.

Page 53, Lines 1-3
Participation may be as a participant, mentor, coach, evaluator, or controller, but not as an observer. Multiple assignees to a given Key Position could take credit for the same drill if their participation is a meaningful opportunity to gain proficiency.

Event or circumstances requiring guidance interpretation:
The event/circumstance principally involves utilities with common EOFs where the functions of EOF Senior Manager, EOF Key Protective Measures and EOF Communicator are assigned to Key Positions that generically support multiple nuclear sites.

Utilities with a common EOF established to support multiple nuclear sites have made Key Position assignments to provide implementation of the three functions mentioned above and described in NEI 99-02 rev 6.

ERO members assigned to each function are grouped and monitored to ensure that each member receives a "meaningful opportunity to gain proficiency". This membership is accounted for at the end of each quarter and entered into the ROP process.

Where common EOFs are established supporting multiple sites the EOF, ERO membership is trained, including involvement in a drill and exercise program to ensure that they are fully qualified to respond to each site served by that EOF when emergencies are declared.

To restate the issue another way, this membership represents each nuclear site served by the EOF operationally and functionally.

In general given this prescribed condition procedures, processes and protocols have been established that have generic application or in words the **skill set is similar** in application regardless of the nuclear site involved.

Where benchmarking has been conducted, a common approach to calculating Participation Credit for this EOF Key Position set is as follows;

Participation Credit is given for these "generic" key positions and counted (as specified in NEI 99-02) for all nuclear sites served by the EOF when a Key Position member is provided a meaningful opportunity to gain proficiency during any one nuclear site drill or exercise. This practice is not a new practice nor is this practice the result of a collaborative effort. This has been establish by each utility separately
.

DEP Credit is only provided to the nuclear site included in the drill or exercise additionally as invoked by NEI 99-02.

If licensee and NRC resident/region do not agree on the facts and circumstances explain

NRC region does not agree with the generic participation credit approached and has specified that participation credit can ONLY be provided to the specific site involved in the drill or exercise.

Potentially relevant existing FAQ numbers

NA

<u>Response Section</u>

Proposed Resolution of FAQ

1) Revise NEI 99-02 to provide clarifying language to more effectively communicate counting participation credit for NEI 99-02 EOF positions when centralized Emergency Offsite Facilities are utilized.
2) The concept of a centralized Emergency Offsite Facility was being utilized prior to the issuance of NEI 99-02 at a minimum of three utilities. Tennessee Valley Authority, Exelon and the Salem-Hope Creek facility each had centralized Emergency Offsite Facilities. Additionally Exelon executed a pilot for NEI 99-02 where participation credit was counted for each plant served by the centralized Emergency Offsite Facility.

If appropriate, provide proposed rewording of guidance for inclusion in next revision.
[PARTICIPATION]

NEI 99-02 Revision 6, page 54

expected to be just a phone talker who is not tasked with filling out the form. There is no intent to track a large number of shift communicators or personnel who are just phone talkers.

Where an approved centralized Emergency Offsite Facility (EOF) serves multiple nuclear plant sites at a number of locations (fleet concept) participation may be counted for each of the nuclear sites served by the centralized EOF when;

- Key EOF Positions are functionally aligned as prescribed in NEI 99-02.
- Key EOF Positions support similar key skills and functions
    - When only site specific attributes (i.e., evacuation sections, EALs, etc.) differ but the key skills and functions to attain the attributes are similar then participation credit may be counted.
- All other NEI 99-02 criteria for participation are met.
- Specifically the following criteria shall be met to grant participation credit:
    - Dose assessment – same software used for all sites.
    - Field monitoring team tracking and control are the same if EOF directs teams. Radio systems are the same.
    - PAR process is the same.
    - Notification form and equipment the same.
    - There are advisors on each team in the EOF that are familiar with each plant so that the EOF Senior Manager and EOF Key Protective Measures ERO Member may be advised on EALs, site terrain and special weather condition attributes, plant operation (BWR and PWR experience) and radiation monitoring system characteristics.

[DRILL AND EXERCISE PERFORMANCE]

NEI 99-02 Revision 6, page 48

the exercise. Thus, a licensee may choose to not include a PAR beyond the 10-mile EPZ as a DEP PI statistic due to its ad hoc nature.

If a licensee discovers after the fact (greater than 15 minutes) that an event or condition had existed which exceeded an EAL, but no emergency had been declared and the EAL is no longer exceeded at the time of discovery, the following applies:

- *If the indication of the event was not available to the operator, the event should not be evaluated for PI purposes.*
- *If the indication of the event was available to the operator but not recognized, it should be considered an unsuccessful classification opportunity.*

- *In either case described above, notification should be performed in accordance with* NUREG-1022 and not be evaluated as a notification opportunity.

Where an approved centralized Emergency Offsite Facility (EOF) serves multiple nuclear plants sites at a number of locations (fleet concept) DEP for any drill or exercise may be only counted for the participating nuclear sites served by the centralized EOF and principally involved in actual or simulated emergency event.

FAQ 10-01

FAQ TEMPLATE

Plant:	Generic		
Date of Event:	NA		
Submittal Date:	January 21, 2010		
Licensee Contact:	Ken Heffner	Tel/email:	919-270-5611/kmh@nei.org
NRC Contact:	Nathan Sanfiilipo	Tel/email:	301-415-3951/nathan.sanfillipo@nrc.gov

Performance Indicator:

NA

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective when approved

Question Section

Existing Guidance on Page E-3 beginning at line 16

Withdrawal of FAQs

A licensee may withdraw a FAQ after it has been accepted by the joint ROP Working Group. Withdrawals must occur during an ROP Working Group monthly (approximately) meeting. However, the ROP Working Group should further discuss and decide if a guidance issue exists in NEI 99-02 that requires additional clarification. If additional clarification is needed then the original FAQ should be revised to become a generic FAQ.

Event or circumstances requiring guidance interpretation

The staff has expressed concern that when a licensee withdraws an FAQ, the efforts that they expend during the discussions preceding the withdrawal of the FAQ are not captured.

If licensee and NRC resident/region do not agree on the facts and circumstances explain

NA

Response Section

Proposed Resolution of FAQ

Recommended Change

Withdrawal of FAQs

A licensee may withdraw a FAQ after it has been accepted by the joint ROP Working Group. Withdrawals must occur during an ROP Working Group meeting. However, the ROP Working Group should further discuss and decide if a guidance issue exists in NEI 99-02 that requires additional clarification. If additional clarification is needed then the original FAQ should be revised to become a generic FAQ. In many cases, there are lessons learned from the resources expended by the ROP Working Group that should be captured. In those cases, the FAQ will be entered in the FAQ log as a generic FAQ. If there is disagreement between the staff and industry, both positions should be articulated in the FAQ. These withdrawn FAQs should be considered as historical and are not considered to be part of NEI 99-02. Although they do not establish precedence, they do offer insights into perspectives of both industry and NRC staff and, as such, can inform future decisions to submit an FAQ.

If appropriate, provide proposed rewording of guidance for inclusion in next revision.

See proposed resolution

FAQ TEMPLATE

Plant:	Generic		
Date of Event:	NA		
Submittal Date:	January 21, 2010		
Licensee Contact:	Ken Heffner	Tel/email:	919-270-5611/kmh@nei.org
NRC Contact:	Nathan Sanfiilipo	Tel/email:	301-415-3951/nathan.sanfillipo@nrc.gov

Performance Indicator:
IE04 Unplanned Scrams with Complications

Site-Specific FAQ (Appendix D)? No

FAQ requested to become effective when approved

Question Section

NEI 99-02 Guidance needing interpretation (include page and line citation):

NEI 99-02 Revision 6, Page 20 lines 22 to 46, page 22 lines 35-45, and page 23 lines 1-10 discuss whether or not Main Feedwater was available following an unplanned scram.

Event or circumstances requiring guidance interpretation:

When FAQ # 467 was approved, the response section stated that the guidance in NEI 99-02 should be reviewed to see if it needs to be revised based on circumstances that might require the availability of feedwater beyond 30 minutes and whether consideration of the scram response time window remains an appropriate marker for judging a complication to recovery from an unplanned scram.

The purpose of this FAQ is to define what constitutes scram" response" as opposed to scram "recovery."

If licensee and NRC resident/region do not agree on the facts and circumstances explain

In FAQ #467, the plant's recommendation was to change the guidance in two locations:

1. If operating prior to the scram, did Main Feedwater cease to operate and was it unable to be restarted during the reactor scram response? The consideration for this question is whether Main Feedwater could be used to feed the reactor vessel if necessary. When considering the availability of Main Feedwater, it should be able to be restarted within the first 30 minutes following the scram.

   The Senior Resident's response was that this guidance change would not capture those events that are of higher safety significance because main feed is not available, even if it was not required to be used, and 30 minutes is a completely arbitrary number.

2. Operations should be able to start a Main Feedwater pump and start feeding the reactor vessel with the Main Feedwater System within 30 minutes of the initial scram transient. During startup

conditions where Main Feedwater was not placed in service prior to the scram, the question would not be considered, and should be skipped.

This Senior Resident's response to this proposed change was that even if the main feed steam supply is temporarily isolated, the PI should capture those events where main feed couldn't be restored in a relatively short time. "It might be different if the equipment was designed such that restoration was not possible

Potentially relevant existing FAQ numbers
467

Response Section

Proposed Resolution of FAQ

The first 30 minutes after the scram is considered scram response and Main Feedwater must be available in the event that it could be needed. After 30 minutes is considered scram recovery.

If appropriate, provide proposed rewording of guidance for inclusion in next revision.

FAQ 10-03

Plant: Wolf Creek Generating Station (WCGS)
Date of Event: April 28, 2009
Submittal Date: March 18, 2010
Licensee Contact: Terry Damashek Telephone: 620 364 8831, ext #8012
Email: tedamas@wcnoc.com
NRC Contact: Christopher Long Telephone: 620 364 8653
Email: chris.long@nrc.gov

Performance Indicator: IE04, Unplanned Scrams with Complications
Site-Specific FAQ (Appendix D)? No
FAQ requested to become effective when approved.

QUESTION

NEI 99-02 Guidance needing interpretation:
Page 19, "Was Main Feedwater unavailable or not recoverable using approved plant procedures following the scram." Attachment H, Page H-4, Lines 36 through 39, "Some other designs have interlocks in place to prevent feeding the steam generators with main Feedwater unless reactor coolant temperature is greater then the no-load average temperature. These plants should also answer this question as "No" and move on."

Event or Circumstances requiring guidance interpretation:
On April 28, 2009, WCGS experienced a reactor trip (scram)/turbine trip due to 'B' Steam Generator (SG) lolo water level caused by a main feedwater regulating valve (MFRV) controller failure. All equipment functioned as required. Steam generator water level control during and immediately after the scram was not an issue and the plant responded as expected. Both Steam Driven Main Feedwater Pumps tripped as designed on the feedwater isolation signal and steam generator water levels were restored and maintained by auxiliary feedwater flow per design. Several days later after repairs to the MFRV controller were complete, during preparations for restart and return of the plant to power, both Steam Driven Main Feedwater Pumps required maintenance assistance to return them to service. The event was reported in the monthly performance indicator IE01 as an Unplanned Scram per 7000 Hours.

Wolf Creek Nuclear Operating Corporation (WCNOC) believes that current plant design, which includes an Engineered Safety Features Actuation System (ESFAS) interlock (Reactor Trip, P-4) to prevent feeding the SGs with the Main Feedwater System when Tavg is < 564 °F (no-load Tavg is 557 °F) and the reactor tripped, would result in answering "No" to the question "Was Main Feedwater unavailable or not recoverable using approved plant procedures following the scram?" WCNOC's position is based on NEI 99-02 Rev 5, page H-4, Paragraph H 1.5, lines 36-39 which states:

> "Some other designs have interlocks in place to prevent feeding the steam generators with main Feedwater unless reactor coolant temperature is greater than the no-load average temperature. These plants should also answer this question as "No" and move on."

On a normal scram from power, WCGS expects to receive a feedwater isolation signal on low Tavg coincident with P-4 and a LoLo SG Feedwater Isolation signal. If main feedwater does not isolate following a scram, manual isolation of feedwater is directed in the scram response procedures. The logic for feedwater isolation on low Tavg coincident with P-4 can be reset any time after the signal is received, however the SG LoLo water level isolation signal cannot be cleared until the SG LoLo water level condition is cleared. The normal response to a scram from power Emergency Response procedures do not include reset of feedwater isolation signal for low T_{avg} coincident with P-4, or restart of the Steam Driven Main Feedwater Pumps. Once conditions stabilize and water levels are recovered in the SGs, the Normal Shutdown to Hot Standby procedure entered from the scram procedure provides the Operator options to restart the Steam Driven Main Feedwater Pumps, or the Startup Feedwater pump, or continue to maintain SG water level using the Auxiliary Feedwater Pumps.

The following information is from the WCGS Technical Specification Bases and describes the functions of the ESFAS interlock -Reactor Trip/P-4 (which include feedwater isolation coincident with P-4):

- *Engineered Safety Feature Actuation System Interlocks - Reactor Trip, P-4*

  The P-4 interlock is enabled when a reactor trip breaker (RTB) and its associated bypass breaker is open. Manual reset of SI following a 60 second time delay, in conjunction with P-4, generates an automatic SI block. This Function allows operators to take manual control of SI systems after the initial phase of injection is complete. Once SI is blocked, automatic actuation of SI cannot occur until the RTBs have been manually closed.

  The functions of the P-4 interlock are:

  - Trips the main turbine;
  - *Isolates MFW with coincident low Tave;* [emphasis added]
  - Allows manual block of the automatic reactuation of SI after a manual reset of SI; and
  - Allows arming of the steam dump valves and transfers the steam dump from the load rejection Tave controller to the plant trip controller; and
  - Prevents opening of the MFW isolation valves if they were closed on SI or SG Water Level – High High.

  Each of the above Functions is interlocked with P-4 to avert or reduce the continued cooldown of the RCS following a reactor trip. An excessive cooldown of the RCS following a reactor trip could cause an insertion of positive reactivity with a subsequent increase in core power. To avoid such a situation, the noted Functions have been interlocked with P-4 as part of the design of the unit control and protection system. [emphasis added]

If Auxiliary Feedwater cannot maintain adequate decay heat removal for any reason, guidance is provided in emergency response procedure EMG FR H-1, "Response to Loss of Secondary Heat Sink," to restore the Main Feedwater System on a loss-of-all-feedwater flow to the steam generators. It gives directions to defeat isolation signals by installing four to six jumpers per SG behind the main control boards. Utilization of this pathway would result in a SCRAM with Complications because WCNOC would have to answer 'Yes' to the next question, "Was the scram response procedure unable to be completed without entering another EOP?" found on page 20, lines 2 & 3 and Figure 2.

NRC Senior Resident Inspector Position:

SRI Position Summary

The SRI disagrees with Wolf Creek and feels that the April 28 trip should have been reported as a scram with complications. On April 28, 2009, Wolf Creek did not have the ability to restore and use main feedwater in normal or emergency operating procedures because all three main feedwater pumps required maintenance, and not because of isolation signals. Any of the three main feedwater pumps can be procedurally started in Mode 3. The FWIS, including P4+Tavg <564F and lo lo S/G level, can be cleared with the pushbuttons or jumper wires per normal or emergency operating procedures. Page H-4, lines 27 to 29 state that the PI measures the ability [emphasis added] to implement emergency procedures on loss of auxiliary feedwater. Actual implementation of other emergency procedure is monitored elsewhere. This approach is also consistent with page H-5, lines 20-23, which provide for clearing of isolation signals in order to use main feedwater.

SRI Basis

The SRI believes that although there is a Feedwater Isolation Signal (FWIS, P4 interlock), the April 28, 2009 scram should still count towards the Scrams with Complications PI. Wolf Creek procedure GEN 00-005, "Minimum Load to Hot Standby," revision 62 directs reactor operators to depress the FWIS reset pushbuttons and check that the P4 FWIS anunciator is clear. Main feedwater valves can then be opened even if reactor trip breakers are open, coincident with reactor coolant system temperature below 564F. The control room pushbutton circuitry has a retentive memory device and the valves will remain open until the reactor trip breakers are cycled or the RCS goes above and below 564F. If this happens a second time, the reset button can be depressed again and main feedwater can be re-established. This interlock does not prevent feeding the steam generators with main feedwater because of normal (GEN 5) and off-normal (EMG FR-H1) plant procedures and the reset pushbutton. The SRI felt page H-5, lines 20 to 23 state that a FWIS does not constitute a loss of main feedwater as long as it can be cleared and feedwater restarted. Procedure EMG FR-H1 also provides instructions for reactor operators to clear the P4+564F and lo-lo steam generator level signals with jumper wires. The FWIS hand switch could also be used. The flow path was viable.

The SRI agrees with Wolf Creek's position that actual use of EMG FR-H1 would count towards the PI because of entry into another EMG per NEI 99-02 section H 1.6. The plant trip on April 28, 2009, did not require entry into procedure EMG FR-H1.

Procedure EMG FR-H1 allows and provides steps to use any of the three main feed pumps. However, if procedure EMG FR-H1 was used on April 28, 2009, the main feedwater portion of the procedure would not have been successful because all three main feedwater pumps required maintenance (speed switch, servo valve, and a circuit breaker). Consistent with page 19 of NEI 99-02, Revision 6 and page H-4, lines 24 to 29, the PI monitors the ability of main feedwater to be used to feed the steam generators if necessary in emergency operating procedures. On April 28, 2009, Wolf Creek did not have the ability to restore and use main feedwater in normal or emergency operating procedures because all three main feedwater pumps needed maintenance, and not because of isolation signals.

Wolf Creek does not appear to be a design that applies to page H-4, lines 36 to 38. The P4 FWIS occurs with Tave at 564F which is above no load Tave of 557F cited in H-4. A Tave of 564F corresponds to a reactor power of approximately 11%. The Wolf Creek total plant setpoint document defines low Tave as 553F (P-12) and lo lo Tave as 550F (Turbine loading stop). If auxiliary feedwater actually failed, and EMG FR-H1 was used, then the RCS is likely to be above 557F or 564F, and trending up. Thus, RCS temperature is likely not to be a concern prohibiting initial use of main feedwater until the plant is cooled below 564F and the signal would have to be reset again.

Wolf Creek did count the March 2008 scram as complicated. There is no discussion of the main feedwater in Wolf Creek's NRC PI procedure.

Expected reactor trip parameters should not be used as a reason to exclude main feedwater availability from this performance indicator. But, if the NEI/NRC ROP Working Group determines that Wolf Creek is correct, then the Appendix H should be rewritten to explicitly exclude Westinghouse units from the main feedwater availability portion of this performance indicator.

Potentially Relevant Existing FAQ Numbers:
None

RESPONSE:

Proposed Resolution of FAQ:
This event should not count against the Unplanned Scrams w/Complications PI.

FAQ 10-04

FAQ TEMPLATE

Plant: Browns Ferry Nuclear Plant, Unit 1 (BFN 1)

Date of Event:	6/1/2007		
Submittal Date:	4/21/2010		
Licensee Contact:	Rod Cook	Tel/email:	(423) 751-2834
NRC Contact:		Tel/email:	

Performance Indicator: MS06 – MS10

Site-Specific FAQ (Appendix D)? Yes ~~or No~~

FAQ requested to become effective when approved or ___________

Question Section

NEI 99-02 Guidance needing interpretation (include page and line citation):

Add BFN 1 to Table 7 of Appendix F, Generic CCF Adjustment Values. The values for BFN 2 and 3 should be the same for BFN 1.

Event or circumstances requiring guidance interpretation:

Return of BFN 1 to operating status during summer of 2007

If licensee and NRC resident/region do not agree on the facts and circumstances explain
NA

Potentially relevant existing FAQ numbers
NA

Response Section

Proposed Resolution of FAQ
Add BFN 1 to Table 7 of Appendix F with plant-specific Generic CCF Adjustment Values.

If appropriate, provide proposed rewording of guidance for inclusion in next revision.

The following is proposed to be added to Appendix F, Table 7:

	EDG	**MDP Running or Alternating**$^{+}$	**MDP Standby**	**MDP Standby**	**TDP ****	**MDP Standby**
Browns Ferry 1	1.25	1	1	1	1	3

Figure E-1

FAQ 10-05

Plant:	**Palo Verde Nuclear Generating Station**		
Date of Event:	**December 3, 2009**		
Submittal Date:	April 14, 2010		
Licensee Contact:	Del Elkinton	Tele/email:	623-393-5656 Delbert.Elkinton@aps.com
NRC Contact	Ryan Treadway	Tele/email:	623-393-3737 Ryan.Treadway@nrc.gov

Performance Indicator: IE04 – Unplanned Scrams With Complications

Site-Specific FAQ (Appendix D)? Yes

FAQ requested to become effective when approved.

QUESTION SECTION

NEI 99-02 Guidance needing interpretation (include page and line citation):

IE04 page 21 Lines 2 -10:

> "Was the scram response procedure unable to be completed without entering another EOP?"

Appendix H2.3 PWR Case Study 3, page H-14 Line 9 through H-17 line 23:

> This case study discusses a PWR event with loss of forced circulation and entry into natural circulation that was answered "NO" for question six regarding entry into EOPs.

The IE04 guidance currently excludes counting loss of forced circulation (LOFC) under the Westinghouse ES01 Emergency Operating Procedure (EOP) scheme, but requires counting the same scenario under the Combustion Engineering CEN-152 EOP scheme. The proposed resolution would add an Appendix D FAQ to also exclude counting LOFC events under the Combustion Engineering CEN-152 EOP scheme.

The Westinghouse exclusion is based on normal scram recovery and restoration of forced circulation being addressed within the single Westinghouse ES01 EOP. Transition to another EOP is not required. For the same LOFC event, the CEN-152 EOP scheme organizes the response into two EOPs, the normal scram and LOFC.

The administrative arrangement of Westinghouse ES01 for a LOFC without a cooldown using natural circulation provides no safety benefit over the arrangement of CEN-152.

Without any other complications, an LOFC event does not require counting as an unplanned scram with complications in the ES01 scheme and it should not count in the CEN-152 scheme.

FAQ 10-05

Event or circumstances requiring guidance interpretation:

On December 3, 2009, Palo Verde Unit 3 experienced a loss of containment instrument air that resulted in an eventual loss of normal reactor coolant pump (RCP) seal bleed-off flow. This caused the seal bleed-off relief valve to lift to send bleed-off to the reactor drain tank (RDT). To prevent overfill of the RDT and a breach of the RDT rupture disk, control room staff elected to scram the reactor and secure all four RCPs. After completing the standard post-trip actions (SPTAs), the plant remained in mode 3 via natural circulation until forced circulation was restored after instrument air was restored in containment. A cooldown using natural circulation was NOT initiated. The safety functions were met. All rods fully inserted, the turbine tripped automatically upon scramming the reactor, class and non-class AC busses remained energized, no safety injection occurred, and main feedwater remained in service or available throughout the event. During the event, charging remained available through the pressurizer auxiliary spray line. Letdown and the ability to pump down the RDT were lost because the respective air-operated containment isolation valves shut upon loss of instrument air pressure. These losses were addressed by the use of abnormal operating procedures that do not require entry into another EOP. A contingency action from EOP standard appendices was used to manually align turbine gland seal steam. The RDT rupture disk remained intact, and the each of the RCPs' 3-stage seals operated per design without experiencing abnormal leak-off or heating.

To address the event after diagnosing the loss of instrument air inside containment, the control room staff entered the SPTA EOP. The RCPs were secured and the LOFC EOP was entered to control the plant using natural circulation until forced circulation was restored.

If licensee and NRC resident/region do not agree on the facts and circumstances explain

The NRC resident and Palo Verde are in agreement on the facts of the event and the content of NEI guidance. Both agree that after the reactor trip and manual shutdown of the RCPs, the station entered a second EOP (the LOFC EOP) to maintain heat removal via natural circulation until instrument air and forced circulation were restored.

The NRC resident and Palo Verde differ on whether the guidance provided in NEI 99-02 regarding the Westinghouse ES01 EOP scheme provides an adequate basis for a plant specific exemption that would permit a "No" answer for the question whether the scram procedure was able to be completed without entering another EOP. The NRC resident's contention is based on the purpose of the performance indicator, which is track performance related to "events or conditions that may have the potential to present additional challenges to the plant operations staff and therefore, may be more risk- significant than uncomplicated scrams" given the challenges the Operations staff faced during the December 3, 2009, Unit 3 loss of instrument air event.

Potentially relevant existing FAQ numbers

There are no relevant existing FAQs

FAQ 10-05

RESPONSE SECTION
Proposed Resolution of FAQ

Enter a Combustion Engineering NSSS vendor specific FAQ into Appendix D of NEI 99-02 that would permit a "NO" answer in response to the question "Was the scram response procedure unable to be completed without entering another EOP?" for specific scram events that require entry into the Loss of Forced Circulation EOP provided the response did not include a plant cooldown using natural circulation and the event was not initiated by a loss of offsite power.

To align the December 3, 2009, Palo Verde scram with the indicator as described in the IE04 guidance for Westinghouse design and EOPs, approval of this FAQ would allow the event to be counted only as an unplanned scram.

If appropriate, provide proposed rewording of guidance for inclusion in next revision.

Not applicable – Appendix D FAQ

FAQ 10-05

Supplementary Information

Comparison of Palo Verde Unit 3 December 9, 2009 Event and Westinghouse ES0.1 EOP

The following is a comparison of the control of key parameters during the event in comparison to Westinghouse EOP ES01:

ES01 Action	Palo Verde Unit 3 Action
Caution to use other EOP if safety injection occurs.	No safety injection occurred or required.
Verification of RCS Temperature stability and trends, with or without RCPs running	Temperature was maintained in the normal post reactor trip band of 560 to 570 degrees F in accordance with procedures.
Verification of FW status	Feedwater operated throughout the event in accordance with procedures.
Verification that all control rods inserted	All CEAs inserted.
Verification of pressurizer level control, manually controlling via charging and letdown control	Pressurizer level was controlled manually in the prescribed range of 35 – 55 % in accordance with procedures via control of charging pumps.
Verification of charging and letdown, manually placing these into service	Charging remained available via auxiliary pressurizer spray. Letdown was lost and restored (after restoration of instrument air inside containment) in accordance with procedures.
Verification of pressurizer pressure	Pressurizer pressure maintained in the range of 2050 to 2283 psia and within the prescribed band of 1837 – 2285 psia. Auxiliary pressurizer spray via charging was available for in accordance with procedures.
Verification and maintenance of SG level	Steam generator level was maintained above the prescribed 35% wide range minimum and within the prescribe narrow range band of 45 – 60%.
Verification of AC busses	Busses remained energized using off-site power throughout the event, EDGs did not start and were not required.
Control of Steam Dump Mode	Steam Bypass remained in Remote- Auto in accordance with procedures.
Verification of RCP in loop with surge line running or verification of natural circulation	RCPs were turned off after the reactor trip. Natural circulation was maintained in accordance with procedures. (NOTE: The applicable procedure was the LOOP /LOFC Optimal Recovery EOP.)

FAQ 10-05

ES01 Action	Palo Verde Unit 3 Action
Determination whether Source Range Detectors should be energized	Startup channels placed in service in accordance with procedures.
Shutdown of Unnecessary Equipment	Not applicable
Maintenance of Stable Plant Conditions	Plant was stabilized in mode 3 in natural circulation until force circulation was restored.*
Determination whether exit of procedure to natural circulation cooldown is required	No cooldown was required

Palo Verde follows the Combustion Engineering CEN-152 EOP scheme in which loss and restoration of forced circulation and maintenance of natural circulation are addressed in the LOOP / LOFC optimal recovery EOP. The CE normal scram process is to enter the SPTA EOP followed by entry into the Reactor Trip EOP if forced recirculation is maintained. After the plant is stabilized, operators transition to the general operating procedures to restart or cooldown the plant. Entry into the LOOP / LOFC EOP is necessary if forced circulation is lost or secured. The CEN-152 technical guidance offers no technical reason why the LOFC and natural circulation without cooldown is arranged in an EOP separate from the Reactor Trip EOP.

For the loss of forced circulation event with entry into natural circulation without a cooldown, the difference in the arrangement of the EOP schemes is administrative. The arrangement of the procedures, whether in either the Westinghouse ES01 normal trip process or the CE LOFC/LOOP EOP, makes no difference to the response and outcome for this event. The difference does not "have the potential to present additional challenges to the plant operations staff and therefore, may be more risk-significant than uncomplicated scrams," as stated in the purpose of the indicator on page 18, lines 5 and 6. The arrangement is therefore administrative in nature.

Because the administrative differences between the organization of the EOP schemes provide no evidence of additional risk or consequence for the Unit 3 December 3 trip, the entry in to the LOOP/LOFC EOP should result in a conclusion that the trip was not complicated as provided in the NEI 99-02 guidance.