NRC Response to
FAQ 12-01 (Withdrawn) re. Columbia DG3 Failure
For August 29, 2012 ROP WG Meeting

Plant: Columbia Generating Station (CGS)
Date of Event: February 28, 2010
Submittal Date: March 6, 2012
Licensee Contact: Richard Wolfgramm Tel/email: (509) 377-4174 rpwolfgramm@energy-northwest.com

NRC Contact: Jeremy Groom Tel/email: (509) 377-2112 jeremy.groom@nrc.gov

Performance Indicator: MS06
Site-Specific FAQ (Appendix D)? Yes or No: Yes
FAQ requested to become effective when approved.

Question Section

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

The guidance in question is on page F-26, lines 3 through 15, of NEI 99-02, Rev 6.

EDG failure to start: A failure to start includes those failures up to the point the EDG has achieved required speed and voltage. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

EDG failure to load/run: Given that it has successfully started, a failure of the EDG output breaker to close, to successfully load sequence and to run/operate for one hour to perform its monitored functions. This failure mode is treated as a demand failure for calculation purposes. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

EDG failure to run: Given that it has successfully started and loaded and run for an hour, a failure of an EDG to run/operate. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

Event or circumstances requiring guidance interpretation:

On February 28, 2010, CGS was testing an Emergency Diesel Generator (EDG). Refer to figure 1 for Load and Current trace of the subject event. The EDG successfully started, the EDG output breaker successfully closed (T = 0 minutes), the EDG successfully load sequenced up to fully loaded (T = 21 minutes), after 45 minutes the EDG experienced unexpected load oscillations of 350 kw (T = 66 minutes), after 17 minutes the load was lowered (T = 83 minutes) and the 350 kw oscillations were observed to continue another 16 minutes of operation until the EDG was unloaded (T = 99 minutes) and shut down.

When the EDG was shutdown, plant staff made a log entry stating, "After running DG3 ***fully loaded over an hour*** per SOP-DG3-START, observed … Swings from 300 to 320 amps, Swings from 2200 to 2500 KW …". Root cause investigation later identified that the governor actuator had failed 45 minutes after reaching full load (T = 66 minutes). At that point the EDG was no longer capable of performing its monitored function. The MSPI Basis Document identifies that the monitored function is to provide 4160 VAC emergency power to safety related Division 3 HPCS equipment and has a mission time of 24 hours. The frequency and magnitude of load oscillations were such that the DG could not have provided power to required safety related loads for 24 hours. To be clear, the EDG did run for more than an hour after breaker closure, but only 45 minutes after reaching full load at which point it was no longer capable of performing its monitored function. This was interpreted as an "EDG Failure to Load/Run" based on the guidance in effect at the time and was reported as such.

On October 26, 2011, FAQ Number 487 was issued with an effective date of January 1, 2012, meaning that licensees will begin applying the FAQ resolution to 1Q2012 data reported to NRC in April 2012. The FAQ clarified that the one hour time limit for differentiating between an "EDG Failure to Load/Run" and an "EDG Failure to Run" is after the EDG output breaker successfully closed. The FAQ resolution was needed because the definitions of "EDG Failure to Start", "EDG Failure to Load/Run", and "EDG Failure to Run" were confusing and contradictory. Information Systems Laboratories, Inc, performed a review for the NRC of EDG and Fuel Oil Transfer Pump failures to support the changes to the EDG failure definitions. In the report, it specifies that the key differences between NEI 99-02, Rev 6, and the proposed changes includes changes to the load/run failure definition from the failure to successfully load sequence and run/operate for one hour to the failure to run for one hour after breaker has received a signal to close and clarification of run failure to not require the EDG to be fully loaded. The primary objective of the failure definition changes is to sharpen the transition points between the three failure modes.

<u>If licensee and NRC resident/region do not agree on the facts and circumstances explain</u>:

CGS and the CGS NRC Senior Resident Inspector (SRI) do not agree that CGS properly reported the February 28, 2010 EDG failure. NEI 99-02 defines "EDG failure to load/run". In part, it states: "Given that it has successfully started, a failure of the EDG output breaker to close, to successfully load sequence and to run/operate for ***one hour*** to perform its monitored functions." The intent of this FAQ is to clarify that based on the guidance available at the time the start time for the "one hour" period begins once the EDG has completed its load sequence and is loaded (at T=21 and not at T=0 (as per figure 1)). Based on the response to FAQ Number 487, CGS understands that as of 1/1/2012 the "one hour" period begins at output breaker closure (T=0 per figure 1).

<u>RESIDENT INSPECTOR POSITION</u>

The inspectors disagree with the licensee's position that NEI 99-02, Revision 6, in effect at the time the February 28, 2010 diesel failure, would require this issue to be reported as an "EDG failure to load run". For the February 28, 2010 diesel failure at Columbia Generating Station, please consider the following sequence of events:

Time on 2/28/10	Event	Elapsed Time following DG Output Breaker Closure
1:40 AM	Division 3 Diesel Generator (DG-3) is Started for testing	N/A
1:57 AM	DG-3 Field is Flashed	N/A
2:16 AM	DG-3 Output Breaker is Shut (some load is immediately placed on the component)	T=0
2:37 AM	DG-3 is fully loaded	T + 21 minutes
3:22 AM	DG-3 first exhibits load oscillations	T + 66 minutes
3:55 AM	DG-3 is unloaded	T + 99 minutes
4:36 AM	DG-3 is secured	T + 140 minutes

Based on the timeline associated with the February 28, 2010 diesel failure, the resident inspectors believe that evaluation under the existing guidance at the time of the issue (NEI 99-02, Revision 6) should have determined that this particular diesel failure is an "EDG failure to run". The two key points for determining the type of failure should be the time the diesel generator output breaker is closed and the time the monitored function is lost.

The inspectors believe that the 1 hour clock that distinguishes the differences between "failure to load run" and a "failure to run" begins at the time the diesel output breaker is shut (in this case, 2:16 AM). Assigning T=0 at breaker closure as opposed to T=21 when full load is reached is more appropriate in this case because the slow loading sequence used during this particular procedure is not representative of how the component performs its monitored function. The inspectors believe that the definition of failure to load run which includes the phrase "the generator successfully load sequenced" is meant to describe how the equipment would respond in an accident condition (short duration load sequence) rather than the 21 minute slow loading that was performed as part of the standard operating procedure.

NEI 99-02 states that only failures that occur when a component fails to run/operate for one hour to perform it monitored functions should be considered "EDG failure to load/run". Specifically, NEI 99-02, Revision 6, Page F-26, Lines 7-9 states:

> *EDG failure to load/run: Given that it has successfully started, a failure of the EDG output breaker to close, to successfully load sequence and to run/operate for one hour to perform it monitored functions*.

Given this definition, the question becomes "could DG-3 have successfully started, the output breaker closed, the generator successfully load sequenced and the component operated to provide its monitored function for one hour?"

Per the Columbia Generating Station MSPI Basis document, the monitored function of DG-3 is to provide 4160V emergency power to safety related Division 3 high pressure core spray (HPCS) equipment. The diesel run performed on February 28, 2010 does not directly test if DG-3 is capable of providing its monitored function (i.e. power is not provided to HPCS components and the generator is not load sequenced). However, the test that occurred on February 28, 2010 did reveal that if called upon, the engine would start, the diesel output breaker would shut and the engine would load and run for greater than one hour. The failure mechanism (foreign material in the governor) is independent of load and the slow loading sequence used during this particular procedure does not in any way demonstrate the diesel's ability to perform its monitored function. What is important is that the generator can supply power to the 4160V bus SM-4 which the component demonstrated the moment the output breaker was closed.

Additionally, Energy Northwest's position that the 1-hour clock starts when the diesel is fully loaded is not consistent with the failure definitions described in NEI 99-02, Revision 6. Specifically, if anything but diesel generator output breaker closure starts the 1-hour clock, then the load/run period would lengthen to something greater than 1-hour. In the case of the February 28, 2010 event, loading of the diesel took approximately 21 minutes, therefore the load/run period would be lengthened to 1 hour and 21 minutes. This is contrary to the NEI 99-02, Revision 6 definition of "EDG failure to load run" which includes only those failures to run/operate for one hour.

Regardless of the time the 1 hour clock started, the resident inspectors believe that this failure should be consider as an "EDG failure to run". Plant data revealed that at 3:22 AM, DG-3 began to exhibit degraded performance but still provided an average (based on 1 minute average) of >2547 KW which is sufficient to meet all post-accident loads. The diesel engine was allowed to continue to operate until about 3:42 AM when the control room operators logged that after running DG-3 fully loaded for **over an**

hour (emphasis added), the component exhibited load swings of 200-300 KW. The component was secured due to the degraded performance shortly after the operators logged the issue with DG-3. Since the component continued to operate after observing the degraded performance, it is not clear if the monitored function was immediately lost or if the component would have continued to operate for its required mission time. To date, the licensee has not performed an engineering evaluation of the degraded condition to determine at what point the monitored function was lost. The inspectors believe that a strong case can be made that a run failure should be assigned based on NEI 99-02, Revision 6, Page F-28, Lines 28-31

> *For a running component that is secured from operation due to observed degraded performance, but prior to failure, then a run failure shall be assumed unless evaluation of the condition shows that the component would have continued to operate for the mission time starting from the time the component was secured.*

INSPECTOR'S PROPOSED ALTERNATE RESOLUTION

On February 28, 2010, the DG-3 at Columbia Generating Station started, loaded and ran for greater than one hour and would have been able to perform its monitored function of supplying power to HPCS equipment. After 66 minutes of operation, the engine first exhibited degraded performance. After 86 minutes of operations, the operators determined (as indicated in the control room log) that performance had degraded to the point that there was no longer reasonable assurance the monitored function could still be provided and the engine was secured. Per the guidance in NEI 99-02, Revision 6, as stated above, this failure should be classified as an "EDG failure to run".

Potentially relevant existing FAQ numbers
FAQ Number 487

Response Section

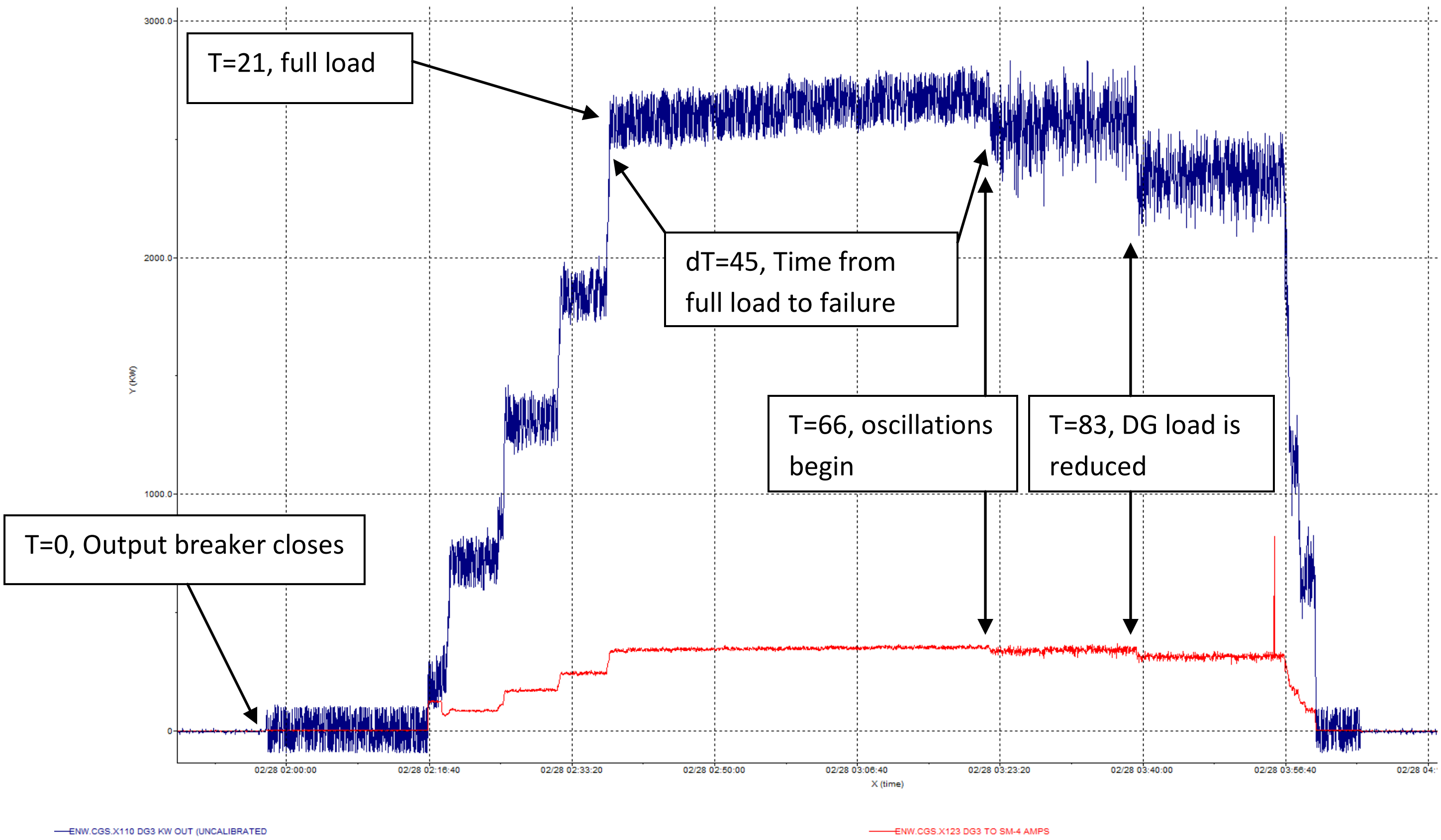
Proposed Resolution of FAQ

Based on the guidance available at the time of the event (Feb 2010), the one hour time period referred to in the definition of "EDG failure to load/run" begins once the EDG has successfully load sequenced to fully loaded conditions. Based on the response to FAQ Number 487, given the same event today (after 1/1/2012), the "one hour" time period begins at output breaker closure.

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

None. Proposed wording included under FAQ 487 is clear and it is already our intent to comply with it.

Figure 1, Load and current profile during DG3 Operation on 2/28/10



NRC Response to Withdrawn FAQ:

NEI 99-02, Revision 6, page F-26, lines 7-9, states, “*EDG failure to load/run:* Given that it has successfully started, a failure of the EDG output breaker to close, to successfully load sequence and to run/operate for one hour to perform it monitored functions.” NEI 99-02, Revision 6, page F-26, lines 13-15, states, “*EDG failure to run:* Given that it has successfully started and loaded and run for an hour, a failure of an EDG to run/operate.” The footnote on page 3 of Revision 6 of NEI 99-02 states, “Changes to data collection rules or practices required by the current revision of this document will not be applied retroactively to previously submitted data. Previously submitted data will not require correction or amendment provided it was collected and reported consistent with the NEI 99-02 revision and FAQ guidance in effect at the time of submittal.”

The “to successfully load sequence and to run/operate for one hour” wording in the EDG failure-to-load/run definition does not convey the intent that the EDG should not be considered running or operating during load sequencing. For example, the guidance does not use the word “then” to denote any intent that the EDG had to be “fully” loaded prior to being able to consider it running and operating. In addition, NEI 99-02 does not state that the EDG has to be fully loaded in order to start the 1-hour period. The EDG had load on it right after the breaker closed; therefore, the NRC considers the EDG to have been "loaded" at this point.

In addition, NEI 99-02 does not define what it means for an EDG to be fully loaded, nor does it require that an EDG be "fully loaded." It does not state whether fully loaded means that the EDG was operated at its design basis loading values, at its maximum load for the current application or test run, or operated at the vendor-specified continuous load rating. Given the ambiguity associated with what it means for an EDG to be "fully loaded," NRC staff does not consider "fully loaded" to be a condition in which to start the 1-hour time clock.

The NRC staff evaluated this issue based on the characteristics of the EDG failure (i.e., the functional response of the EDG and the failure mechanism), and applying reasonable decision-making using the guidance in effect at the time of the failure. The oscillations were caused by foreign material in the governor – a condition that had existed for several years and that did not impact prior breaker closure and sequencing operations. Figure 1 in this FAQ shows that the oscillations did not occur during the breaker closure or the load sequencing or gradual loading action. Rather, the oscillations occurred 66 minutes after breaker closure and 45 minutes after the full load (for purposes of the test run) was achieved, which is indicative of a challenge to the EDG's ability to continue to run for its mission time. Even though the foreign material existed in the governor for several years, the EDG had started and load sequenced several times without failure. Therefore, this failure appears to have been exacerbated by the running (vice start or loading) of the EDG.

Because Figure 1 data is more reflective of an EDG failure-to-run for its mission time rather than a loading failure, the EDG failure at Columbia should have been reported as a failure-to-run.

FAQ 12-02
Counting of Compensatory Hours for Perimeter Intrusion Detection System

Plant: Generic
Date of Event: January 2011
Submittal Date: July 13, 2011
Licensee Contact: Ron Gaston, (630) 657-3359, ronald.gaston@exeloncorp.com
NRC Contact: Brian Yip (301) 415-7638, Brian.Yip@nrc.gov

Performance Indicator: Protected Area Security Equipment Performance Index

Site-Specific FAQ (App. D)? No

FAQ requested to become effective: Upon Approval

Question Section

NEI 99-02 Guidance Needing Interpretation:

The purpose and scope of the Physical Protection Cornerstone, as well as the associated Protected Area Security Equipment Performance Index Performance Indicator (PI), discussed in Section 2.7 of NEI 99-02, Revision 6.

Event or circumstances requiring guidance interpretation:

Effective March 31, 2010, a change to 10 CFR Part 73 required that intrusion detection equipment be capable of detecting both attempted and actual penetration of the protected area (PA) perimeter barrier before completed penetration of the PA perimeter barrier. The requirement for detection prior to penetration was a new requirement under the new security regulation that impacted sites that have their perimeter intrusion detection system (PIDS) installed inside the PA barrier.

Following the revision to 10 CFR Part 73, the NRC determined that the Early Warning System (EWS) used to satisfy PIDS for a licensee did not meet criteria outlined in the regulation. Compensatory measures were immediately implemented by the licensee to comply with the revised section 73.55 requirements until modifications to the system could be implemented.

The NRC questioned whether the hours currently being compensated to address the non-compliance should be counted against the Protected Area Security Equipment Performance Index (PI). The licensee believed that the purpose of the PIDS indicator was to monitor the effectiveness of maintenance for installed systems and that the resulting compensatory hours should not be counted.

The NRC subsequently determined that the purpose for the performance indicator should be revised to clearly state the intent to measure the unavailability of security equipment to perform its intended function.

If licensee and NRC resident/region do not agree on the facts and circumstances, explain:
N/A

Potentially relevant existing FAQ numbers:
None

Response Section

Proposed Resolution of FAQ:

Revise NEI 99-02, Revision 6, and page 71 to read as indicated below:

21 This indicator serves as a measure of ~~a plant's ability to maintain~~unavailability of security equipment ~~unavailability – to be able~~ to perform its intended
22 function. When compensatory measures are employed because a segment
23 of equipment is unavailable – not adequately performing its intended function, there is no
24 security vulnerability but there is indication that something needs to be fixed. The PI also
25 provides trend indications for evaluation of the effectiveness of the maintenance process
26 and ~~also~~ provides a method of monitoring equipment degradation as a result of aging that might
27 adversely impact reliability. Maintenance consideration for protected area and vital area portals
28 are appropriately and sufficiently covered by the inspection program.

Revise NEI 99-02, Revision 6, page 73 to read as indicated below:

18 Compensatory measures: Measures used to meet physical security requirements ~~pending~~ when the
19 ~~return of~~ required equipment ~~to service~~is unavailable. Protected Area protection is not diminished by the use of
20 compensatory measures for equipment unavailability.

Revise NEI 99-02, Revision 6, page 75 to read as indicated below:

16 Degradation: Required system, ~~/~~equipment, or ~~/~~component is no longer available or ~~/~~capable of
17 performing its ~~intended~~ Intended ~~safeguards function~~Function~~— manufacturer's equipment design capability and/or~~
~~18 as covered in the PSP~~.

36 Intended ~~function~~Function: The ability of a component to detect the presence of an individual or display
37 an image as intended by the manufacturer's equipment design capability and as described in the
38 ~~PSP~~Physical Security Plan.

NRC comments on
FAQ 12-03- St. Lucie Unplanned Scram with Complications
For August 29, 2012 ROP WG Meeting

Plant: St. Lucie Unit 1
Date of Event: March 31, 2012
Submittal Date: April 30, 2012
Licensee Contact: Eric Katzman Tel/email: 772-467-7734, eric.katzman@fpl.com
NRC Contact: Tim Hoeg Tel/email: 772-467-7017 tim.hoeg@nrc.gov

Performance Indicator: IE04, Unplanned Scrams with Complications (USwC)

Site-Specific FAQ (Appendix D)? YES

FAQ requested to become effective when approved. This FAQ concerns the St. Lucie Unit 1 March 31, 2012 manual reactor trip that was conservatively reported as an USwC. St. Lucie will revise the 1Q/2012 USwC occurrence data when this FAQ is approved.

Question Section

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

- NEI 99-02, Rev 6, Page 21 Lines 2-13.
- NEI 99-02, Rev 6, Appendix H, Page H-5, Lines 36-46 and Page H-6, Lines 1-12

Event or circumstances requiring guidance interpretation:
On November 27, 2011, St. Lucie Unit 1 was shutdown and commenced a refueling and extended power uprate outage. As a result of the extended shutdown period and very low decay heat, the reactor coolant pump (RCP) was the main driver for heating up the reactor coolant system (RCS) to achieve and maintain normal operating pressure and temperature (NOP/NOT) conditions during the March 31, 2012 reactor startup.

During reactor start-up on March 31, 2012, at approximately 0020 hours, the unit was in Mode 1 and holding at 10% power to complete testing of the steam bypass control system (SBCS), when pressure control valve (PCV) 8802, one of the steam dump to condenser valves, opened unexpectedly. Operators attempted to manually close PCV-8802, but were unsuccessful. At 0022 hours, Operators inserted a manual scram of the reactor and entered emergency operating procedure (EOP) EOP-01, Standard Post Trip Actions, as a result of the manual reactor trip and to address the cooldown caused by PCV 8802 being open. A brief period after the manual scram, it was reported that PCV-8802 went closed after the trip, which terminated the excessive steam demand.

While in EOP-1, at 0030 hours, Operators closed the main steam isolation valves (MSIVs) as directed by contingency step 4.6.D.2.3.1 due to steam generator pressure being less than 750 psia, terminating the cooldown. At 0037 hours, Operations confirmed that the EOP-01 exit condition criteria were satisfied in accordance with section 3.1 and the EOP-01 Diagnostic Flow Chart and entered EOP-02, "Reactor Trip Recovery."

While in EOP-02, at 0044 hours, Operators noted that RCS T_{AVG} had increased to 506 ^oF (from a low of 504 ^oF) and was slowly rising, concurrently the procedure directed that the uncomplicated Reactor Trip Safety Function Status Check for RCS Heat Removal was not met because RCS temperature was below 525^oF. As previously noted, during the reactor startup with very low decay heat in the new reactor core, the temperature increase was slow due to reliance on RCP heat. While in EOP-2, at 0049 hours, the operators secured steam generator blowdown to increase the rate of RCS heat up.

At 0058 hours, Operations completed the EOP-02 directed re-diagnoses of the event by re-performing the EOP-01 diagnostic flow chart. The Shift Manager then determined that EOP-05, "Excess Steam Demand," was the appropriate EOP as a result of not meeting the Reactor Trip Safety Function Status Check for RCS Heat Removal (RCS T_{AVG} was not between 525 and 535^oF). Upon entering EOP-05 it was known that no actions were necessary and none would be taken.

At 0330 hours, EOP-05 was exited as RCP heat addition restored RCS temperature to greater than 525^oF. No EOP-05 actions were performed by Operations other than diagnostic checks to confirm that the excess steam demand was terminated.

Although the Combustion Engineering EOP network directs the exit of EOP-02 if any safety function status checks are not satisfied, in this particular event no steps were taken outside of the EOP-01 and EOP-02 contingency actions to mitigate the event. Because no excess steam demand was in progress, FPL concludes that this event does not meet the definition of an Unplanned Scram with Complications, which is "that subset of unplanned automatic and manual scrams that require additional operator actions beyond that of the "normal" scram," since the plant responded as expected considering reactor coolant temperature was being restored solely by the heat addition from the RCPs.

If licensee and NRC resident/region do not agree on the facts and circumstances explain:
The St. Lucie Resident Inspectors are in agreement with the facts presented above. However, the Resident Inspectors believe NEI guidance wording requires that the scram be counted as an unplanned scram with complications because another EOP was entered.

The Senior Resident further stated that since EOP-05 was not executed and no actions were taken, it is reasonable to consider that this reactor trip is uncomplicated.

Potentially relevant existing FAQ numbers:

FAQ 481, proposed response page H-20, lines 18-46 and page H-21, lines 1-7, discussion includes the following:

> "In the case of a routine scram the procedure entered will be exited fairly rapidly after verifying that the reactor is shutdown, excessive cooling is not in progress, electric power is available and reactor coolant pressures and temperatures are at expected values and controlled."

As discussed above, the excess steam demand transient was terminated once EOP-01 directed closure of the MSIVs, and the reactor coolant temperature response was being restored as expected considering the power history of the core and temperature addition via the RCPs.

Response Section:

Proposed Resolution of FAQ:
This FAQ is proposed as a plant specific exemption [NEI 99-02, Rev. 6, page E-1, lines 18-19] from the guidance of NEI 99-02 because of the unique circumstances that lead to the condition. As previously described, St Lucie Unit 1 was in start up from an extended refuel outage in which a substantial amount of reactor fuel was replaced with new fuel. The result was very low decay heat available at the time of the reactor scram, which resulted in a slower temperature response.

As detailed above, the scram response procedure (EOP-01) was exited to the Reactor Trip Recovery procedure (EOP-02). Due to the RCS heat removal temperature band criteria not being met, the Operators entered another EOP during post trip recovery solely because of direction from another EOP, but no actions were required as a result of that EOP. EOP-02, Step 4.7.1, contingency action, directs restoration RCS temperature to within the band of 525 ^{o}F and 535 ^{o}F. This contingency action was fully met with no other actions required because the RCS temperature was being restored via RCP heat.

EOP-02, Step 4.1 is a continuous action step that has the operators re-verify the "uncomplicated Reactor Trip Safety Function Status Check" acceptance criteria every 15 minutes with the contingency action by re-diagnosing the trip in accordance with the EOP-01 Diagnostic Flow Chart. The RCS Heat Removal control contingency action in EOP-02 is "CONTROL SBCS or ADVs to restore RCS T_{AVG} to between 525 and 535^{o}F" which is different than the EOP-01 contingency action to "ENSURE SBCS or ADVs are restoring RCS T_{AVG} to between 525 and 535^{o}F." The lowest RCS temperature noted was 504ºF and it was rising due to RCP heat to restore RCS T_{AVG} to the required band.

Operators were aware that no excess steam demand was in progress because closure of the ADVs and MSIVs in EOP-01 terminated the cooldown. However, as a result of inconsistencies in

RCS heat removal operator actions with EOP-01 and EOP-02, EOP-05 was required to be entered, but no actions were required.

FPL concludes that although the re-diagnosis of the event directed the operators to enter the most appropriate operational response procedure, the excess steam demand EOP was not "required" in that the EOP did not direct the operators to mitigate or stabilize the transient via the manipulation of any SSCs while within EOP-05.

This is consistent with NEI 99-02, page 21, lines 6-8:

> "This step is used to determine if the scram was uncomplicated by counting if additional procedures beyond the normal scram response *required* entry after the scram." [Emphasis added]

Additionally, NEI 99-02, Appendix H, page H-6, lines 1-3, also addresses the concept of "required" with respect to transition to another EOP during scram response procedures:

> "The criteria in this question are used to verify there were no other conditions that developed during the stabilization of the plant in the scram response that *required* re-entry into the EOPs or transition to a follow on EOP." [Emphasis added]

Based on the above, the St. Lucie Unit 1 manual trip of March 31, 2012 should not be counted as an unplanned scram with complications because of the following unique conditions (very low decay heat):

- Extended refuel outage from Nov 2011 thru March 2012
- Replacement of approximately 50 % of the reactor core and
- The only reactor coolant system heat addition was via the reactor coolant pumps

Operators entered EOP-05 as a result of not being able to meet the RCS heat removal safety function. FPL has entered this event into the corrective action program and is working with Westinghouse to clarify the EOP-02 RCS Heat Removal Safety Function to address RCS temperature based upon the time in core life.

As provided by NEI 99-02, Appendix D and Appendix E, this FAQ is requesting an exception to the guidance as written because of the unique circumstances that lead to the entry into an additional EOP. As previously stated, while the EOP was entered, no actions were directed.

NRC Tentative Response:

In this FAQ, the licensee concluded that the scram does not meet the definition of an Unplanned Scram with Complications (USwC). In addition, the licensee identified guidance in NEI 99-02 that warrants interpretation. However, the licensee also indicated that it conservatively counted this as an USwC in its most recent PI data submittal and requested a plant-specific exemption from the NEI 99-02 guidance because of the unique circumstances that contributed to the entry into an additional EOP. Since the FAQ appears to argue two positions (one, that the scram does not meet the definition of an USwC, and two, that it meets the definition but should be exempted from the guidance) the staff will address both the guidance interpretation and the request for exemption.

Purpose of the USwC Performance Indicator (PI):
The purpose of the USwC PI is to monitor that subset of unplanned automatic and manual scrams that either require additional operator actions beyond that of the normal scram. Such events or conditions have the potential to present additional challenges to plant operators and, therefore, may be more risk-significant than uncomplicated scrams. The USwC performance indicator monitors the following conditions that have the potential to complicate the operator's scram recovery action:

- Reactivity Control
- Turbine Trip
- Power available to Emergency Busses
- Need to actuate emergency injection sources
- Availability of Main Feedwater
- Utilization of scram recovery Emergency Operating Procedures (EOPs)

Definition of the USwC PI:
The USwC indicator is defined, in part, as the number of unplanned scrams while critical, both manual and automatic, during the previous 4 quarters that require additional operator actions as defined by the applicable flowchart (NEI 99-02, page 25, Figure 2). The PWR flowchart focuses on six conditions that distinguish the difference between a complicated and uncomplicated scram. The use of the flowchart minimizes subjective determination so reliable PIs are generated.

Position 1: Request for Interpretation of NEI Guidance:
Excerpt 1: NEI 99-02, Revision 6, page 21, lines 2-13, refers to one of the conditions to consider when determining a scram as an USwC as follows:

> *Was the scram response procedure unable to be completed without entering another EOP?*
>
> *The response to the scram must be completed without transitioning to an additional EOP after entering the scram response procedure (e.g., ES01 for Westinghouse). This*

step is used to determine if the scram was uncomplicated by counting if additional procedures beyond the normal scram response required entry after the scram. A plant exiting the normal scram response procedure without using another EOP would answer this step as "No". The discretionary use of the lowest level Function Restoration Guideline (Yellow 11 Path) by the operations staff is an approved exception to this requirement. Use of the Re-diagnosis Procedure by Operations is acceptable unless a transition to another EOP is required.

The operators transitioned from 1-EOP-02, Reactor Trip Recovery, to 1-EOP-05, Excess Steam Demand (ESD), after re-diagnosis (Safety Functions Status Check) of the scram event. The transitioned occurred because the entry conditions into 1-EOP-02 were not satisfied because T_{avg} was below the allowable band of 525-535°F. Failure of the steam dump valve, which caused the excessive steam demand, along with low decay heat levels contributed to the low T_{avg}. The contingency action in 1-EOP-02 directed the operators to enter either the Appropriate Optimal Recovery Procedure or 1-EOP-15, Functional Recovery. The operators decided to transition to an Appropriate Optimal Recovery Procedure and entered 1-EOP-05 because an excessive steam demand event occurred. No manipulations of controls were taken by operators while in 1-EOP-05. This procedure established an expected response for T_{avg} to be stable or decreasing. In this case, however, the objective was to increase T_{avg} to the 1-EOP-02 allowable band. T_{avg} increased due to heat generation from reactor coolant pump operation. Once T_{avg} reached the 525-535°F temperature band, 1-EOP-05 was exited. In its FAQ submittal, the licensee asserted that the definition of an USwC was not met because no excessive steam demand was in progress. However, the guidance does not list excessive steam demand as a flowchart question. Nor does the guidance define operator actions as manipulations of controls; in fact, none of the flowchart questions ask if operators were required to manipulate controls. The flowchart questions focus on hardware performance, plant response, and operating procedure impacts. The question germane to this FAQ is "Was the scram response procedure unable to be completed without entering another EOP?" The guidance essentially defines "additional operator actions beyond that of a normal scram" as the action of transitioning to another EOP. Because St. Lucie operators transitioned to an additional EOP to support scram recovery, the answer to this question is "yes," and the scram clearly meets this criterion for USwC.

Excerpt 2: NEI 99-02, Appendix H, page H-5, Section H 1.6 provides additional guidance on the conditions to consider a scram complicated as follows:

H 1.6 Was the scram response procedure unable to be completed without entering another EOP?

When a scram occurs plant operators enter the EOPs to respond to the condition. In the case of a routine scram the procedure entered will be exited fairly rapidly after verifying that the reactor is shutdown, excessive cooling is not in progress, electric power is available, and reactor coolant pressures and temperatures are at expected values and controlled. Once these verifications are done and the plant conditions are considered "stable" operators may exit the initial procedure to another procedure

> *that will stabilize and prepare the remainder of the plant for transition to the normal operating procedures. The plant could then be maintained in Hot Standby, to perform a controlled normal cool down, or to begin the restart process. The criteria in this question is used to verify there were no other conditions that developed during the stabilization of the plant in the scram response that required re-entry into the EOPs or transition to a follow on EOP.*
>
> *There are some EOPs that are used specifically at the operator discretion and are not required to be used. In the Westinghouse EOP suite these are Yellow Path functional restoration procedures and the re-diagnosis procedures. These procedures typically verify that the operator is taking the correct action (re-diagnosis) or the stabilization of some minor plant parameters (Yellow path). Use of these procedures is an allowed exception to this step. The transition out of these procedures to an EOP different from the current procedure in effect, i.e. a new procedure or the base procedure, would count as a complication.*

Normal scram response is defined in FAQ 10-02 as follows:

> *Scram Response refers to the period of time that starts with the scram and concludes when operators have completed the scram response procedures and the plant has achieved a stabilized condition in accordance with approved plant procedures and as demonstrated by meeting the following criteria. For a PWR:*
>
> - *Pressurizer pressure is within the normal operating pressure band.*
> - *Pressurizer level is within the no-load pressurizer band.*
> - *Level and pressure of all steam generators are within the normal operating bands.*
> - *RCS temperature is within the allowable RCS no-load temperature band (T_{ave} if any RCS pump running, T_{cold} if no RCS pumps running).*

Normal scram response includes stabilization of plant conditions. RCS coolant temperature was not in the required band for 1-EOP-02 during plant stabilization. Operators noted that RCS temperature was at 506 °F, which is below the required 525-535°F band. Temperature returned to the 1-EOP-02 required band approximately 3 hours after the scram; therefore the scram response was not exited fairly rapidly.

The USwC PI provides information regarding licensee performance in the Initiating Events Cornerstone. The key attributes measured by this PI, as described in IMC 0308, Attachment 1, are human error, procedure quality, design, and equipment performance. The equipment performance attribute is relevant because the failure of the steam dump valve both initiated the event and caused the excessive RCS cooldown. The staff notes that the valve remained failed open for some brief period of time even after the scram. An ESD event primarily affects the reactivity control and RCS heat removal safety functions. In addition, the valve failure created the potential for a Safety Injection (SI) actuation had the operators not manually scrammed the reactor and shut the MSIVs immediately. Although operators may not have been significantly challenged by plant conditions and appear to have adequately responded to the event, the conditions did require additional actions (closure of MSIVs. The excessive cooldown caused by the steam dump valve failure also created the potential to present additional challenges to the plant operations staff and, therefore, may have been more risk-significant than an uncomplicated scram.

The operators transitioned to 1-EOP-05 because an ESD event had occurred. The NEI 99-02 guidance does not distinguish between levels of complication for the USwC; scrams involving minor and significant complications are treated equally under this PI. Although the operators managed the event very well, they were placed in a position where they had to choose to not follow the EOP structure (1-EOP-02). Since the EOP structure provides the operators with defense-in-depth during an event, this scram event highlights the potential need for minor EOP enhancements. The licensee has indicated that such enhancements are being made.

Conclusion regarding the Requested Interpretation of NEI Guidance:
The NRC's conclusion is that the March 31, 2012, scram was appropriately submitted as an USwC, consistent with governing guidance. The staff further believes that this USwC meets the intent of that guidance.

Position 2: Request for Exemption from NEI 99-02:
The FAQ process allows a licensee to request an exemption from the guidance for plant-specific circumstances, such as design features, procedures, or unique conditions. The licensee submitted this FAQ, in part, to request a plant-specific exemption from the NEI 99-02 guidance because of unique circumstances that contributed to the entry into an additional EOP (1-EOP-5, Excess Steam Demand).

NEI 99-02, Appendix D, page D-1, lines 16-21 provides additional information on plant-specific exemptions of the NEI 99-02 guidance as follows:

> *The NEI 99-02 guidance was written to accommodate situations anticipated to arise at a typical nuclear power plant. However, uncommon plant designs or unique conditions may exist that have not been anticipated. In these cases, licensees should first apply the guidance as written to determine the impact on the indicators. Then, if the licensee believes that there are unique circumstances sufficient to warrant an exception to the guidance as written, the licensee should submit a Frequently Asked Question to NEI for consideration at a public meeting with the NRC.*

The NRC staff does not consider the conditions that contributed to the low decay heat level unique. In general, all plants have varying levels of decay heat that depend on operating history, shutdown time, and core loading. The staff also notes that shutdowns of the duration at St. Lucie are not uncommon. The impact of these shutdowns combined with core changes would be considered by engineering and operations staff prior to restart. This condition could exist at any plant and, therefore, is not unique to St. Lucie.

The NRC staff undertook a review of prior exemptions to confirm its application of the NEI guidance governing exemptions based on the precedent established. The staff found that a majority of the granted exemptions were either related to uncommon plant designs or unanticipated environmental conditions that impact the PIs.

Conclusion regarding the Exemption Request:
Because the St. Lucie circumstances are not unique, and based on the precedent established by prior exemptions, the NRC staff does not support the plant-specific exemption.

FAQ 12-04 (Proposed)
HRA Related Occurrences (Generic)

Plant: Perry
Date of Event: June 2, 2012
Submittal Date: August 16, 2012
Contact: John Pelcic **Tel/email:** 440-280-5824 jfpelcic@firstenergycorp.com
NRC Contact: Mark Marshfield **Tel/email:** 440-280-5822 mark.marshfield@nrc.gov

Performance Indicator: OR01 Occupational Exposure Control Effectiveness

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 62, Lines 16 - 22, and associated footnote

Technical Specification High Radiation Area (>1 rem per hour) Occurrence –
A nonconformance (or concurrent nonconformances) with technical specifications or comparable requirements in 10 CFR 20 applicable to technical specification high radiation areas (>1 rem per hour) that results in the loss of radiological control over access or work activities within the respective high-radiation area (>1 rem per hour). For high radiation areas (>1 rem per hour), this PI does not include nonconformance with licensee-initiated controls that are beyond what is required by technical specifications and the comparable provisions in 10 CFR Part 20.

A footnote states that "Concurrent" means that the nonconformances occur as a result of the same cause and in a common timeframe.

Event or circumstances requiring guidance interpretation:

On June 2, 2012, an equipment failure resulted in resin/water slurry flow into the general area hallway of the Radwaste Building El. 574. Indications of changing radiological conditions were available. However, the Radiation Protection staff did not recognize the need to conduct a new radiological survey of the area, which was posted and controlled as a High Radiation Area (HRA) at the time. The failure to perform a timely radiological survey is a performance deficiency and an NRC Performance Indicator occurrence.

Over the next few days, there were two instances of individuals entering this area without Radiation Protection coverage and one instance where an individual was provided a HRA key but did not enter the area.

On June 7, 2012, a Radiation Protection technician performed a radiological survey of the area in preparation for decontamination activities. The survey identified a floor area where dose rates met the Technical Specification criteria for classification as a Locked High Radiation Area (LHRA). After the survey, the Radwaste Building El. 574 area was posted and controlled as a LHRA.

This PI counts nonconformances, or "concurrent nonconformances," with technical specifications. "Concurrent nonconformances" are defined as those that "occur as a result of the same cause and in a common timeframe." In this case, the three instances were as a result of the same cause – the failure of Radiation Protection personnel to recognize the need to perform a new radiological survey. "Common timeframe" is not defined; however FENOC believes that these three instances meet the intent of a "common timeframe." The instances were a result of a single performance deficiency with the same common cause.

The failure to recognize the need to perform a new radiological survey prior to June 7, 2012, was reported as a PI occurrence. Additionally, the three instances of individuals entering the area, or having access without Radiation Protection coverage as a result of the single performance deficiency of not performing the timely survey were conservatively reported pending the outcome of this FAQ.

Since the PI counts nonconformances that "result in the loss of radiological control over access or work activities" and the nonconformance that led to the three entries was the failure of Radiation Protection to recognize the need to perform a new radiological survey, are the two subsequent entries and one potential entry considered to be "concurrent nonconformances" bounded by the failure to recognize the need to perform the new radiological survey?

What is the NRC resident inspector's position?

The NRC resident inspector agreed with the facts and recommended that the FAQ process be followed for resolution.

Potentially relevant existing FAQ numbers

FAQ 203 addresses the footnote in question. However, in FAQ 203, the causes of the two entries were different; therefore, both occurrences counted. FAQ 203 did not address "common timeframe."

Response Section

Proposed Resolution of FAQ

The failure to recognize the need to perform a new radiological survey represents a loss of control over access into a LHRA. However, since the subsequent three instances without Radiation Protection control were a result of the failure to perform the new radiological survey, and were within a limited common timeframe, they can be considered to be "concurrent nonconformances." Only one Technical Specification High Radiation Area PI occurrence should be reported.

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

In the footnote defining "concurrent," "common timeframe" should be defined to be "within the normal period of time between surveys for the specific area."