Progress Energy

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March 31, 2006

SERIAL: BSEP 06-0026 10 CFR 50.54(f)

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Subject: Brunswick Steam Electric Plant, Unit Nos. 1 and 2
Docket Nos. 50-325 and 50-324/License Nos. DPR-71 and DPR-62
Response to Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power

Ladies and Gentlemen:

On February 1, 2006, the NRC issued Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power." Responses to Generic Letter 2006-06 were required to be submitted within 60 days of the date of the letter (i.e., Sunday, April 2, 2006).

The requested information is enclosed. No regulatory commitments are contained in this letter. Please refer any questions regarding this submittal to Mr. Leonard R. Beller, Supervisor - Licensing/Regulatory Programs, at (910) 457-2073.

I declare, under penalty of perjury, that the foregoing is true and correct. Executed on March 31, 2006.

Sincerely,

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Response to Generic Letter 2006-02

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Response to Generic Letter 2006-02

Background

On February 1, 2006, the NRC issued Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power." Responses to Generic Letter 2006-06 were required to be submitted within 60 days of the date of the letter (i.e., Sunday, April 2, 2006).

The requested information follows.

NRC Question 1 Topic

Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA to assist the NPP licensee in monitoring grid conditions to determine the operability of offsite power systems under plant TS.

Question 1(a)

Do you have a formal agreement or protocol with your TSO?

Response to Question 1(a)

Yes, the nuclear plants, including the Brunswick Steam Electric Plant (BSEP), Unit Nos. 1 and 2, operated by Carolina Power & Light Company, now doing business as Progress Energy Carolinas, Inc., manage interfaces with the Transmission Department and the System Planning and Operations Department via a formal interface agreement. Nuclear power plant and transmission system operations are conducted under a vertically integrated utility business model. Under this business model, the transmission system is not in a Regional Transmission Organization (RTO) or operated by an Independent System Operator (ISO) as is the case in other parts of the country. Instead, under our vertically integrated utility business model, the System Operators (i.e., Grid Operators) operate both the transmission and generation systems (i.e., nuclear and non-nuclear) and work in the same company that holds the licenses to operate the nuclear power plants. Nuclear generator offsite power reliability is managed by the System Operators through communications with NRC Licensed Operators and Work Control Management at the plants as governed by the formal Interface Agreement.

Question 1(b)

Describe any grid conditions that would trigger a notification from the TSO to the NPP licensee and if there is a time period required for the notification.

Response to Question 1(b)

With respect to potential anticipated grid problems, the existing interface agreement requires both daily and weekly communications between Nuclear Plant Operations and Transmission System Operations to discuss the status of the plant and the transmission system, review upcoming work activities, and discuss the operating conditions scheduled or anticipated for the current day and the next seven days.

In addition to normal operational communications, the Transmission System Operators initiate communications to the Nuclear Plant Operators for the following infrequent or off-normal situations:

- Tier 1 Transmission Line Out

  A Tier 1 transmission line is a transmission line that is directly connected to the plant switchyard.

- Tier 2 Transmission Line Out

  A Tier 2 transmission line is a transmission line that is not directly connected to the plant switchyard but can affect unit stability when out of service.

- Minimum Load Emergency

  This is a condition when there is not enough load on the grid to support continued full power operation of the nuclear fleet. The non-nuclear generators have already reduced power as low as they can go without jeopardizing grid reliability.

- System Contingency Alert

  A System Contingency Alert is when a single contingency (i.e., possible failure) including reduced import capability could result in all available resources being utilized to meet customer demand and reserve requirements.

- System Reliability Alert

  A System Reliability Alert occurs if a single contingency (i.e., possible failure) could result in a generation / load imbalance that may require load curtailments or firm load shedding to correct. This imbalance could be due to insufficient system resources, insufficient off system resources or transmission import limitations.

- Energy Emergency Alert (EEA Levels 1 – 3)

  The EEA Levels are established by North American Electric Reliability Council (NERC) and defined as follows:

  Alert 1 - All Available Resources in Use. Foresee, or experiencing, conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and concerned about sustaining Operating Reserves. Non-firm energy sales have been curtailed.

  Alert 2 - Load Management Procedures in Effect. Foresee, or have implemented, procedures up to, but excluding, interruption of firm load commitments.

  Alert 3 - Firm Load Interruption Imminent or in Progress. Foresee, or have implemented, firm load obligation interruption. Available energy, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

- Enable Part Time Load Shedding of Non-Critical Plant Loads for Loss of Coolant Accident (LOCA) Voltage Contingency Risk Mitigation

  Part time load shedding prevents one additional circulating water pump from being re-energized by the Startup Auxiliary Transformer upon unit trip. This feature allows use of a lower minimum required switchyard voltage while enabled

- Anticipated LOCA Voltage Support Problem

  In this condition, it is anticipated that, in the near future, offsite power voltage support will become insufficient for the plant to remain connected to offsite power during post trip LOCA load sequencing.

- Actual LOCA Voltage Support Problem

  The grid is in a condition where, if the plant were to trip and go into automatic LOCA load sequencing, the plant would not remain connected to offsite power because the degraded grid voltage relays will actuate.

- Significant Grid Frequency Problem

  The grid is experiencing frequency problems to the extent that there may be a concern regarding continued safe operation of the generator and conditions need to be monitored closely.

- Substation Problem (i.e., Plant Impacting Substation Equipment Status Change)

- Severe Weather Conditions
- Sabotage
- Terrorism

No specific time period is applied. However, for anticipated voltage support problems the requirement is to make the notification promptly.

<u>Question 1(c)</u>

Describe any grid conditions that would cause the NPP licensee to contact the TSO. Describe the procedures associated with such a communication. If you do not have procedures, describe how you assess grid conditions that may cause the NPP licensee to contact the TSO.

<u>Response to Question 1(c)</u>

Grid instability is characterized by frequency fluctuations and/or degraded grid voltage. BSEP plant procedure 0AOP-22.0, "Abnormal System Frequency," provides guidance to plant operators regarding frequency fluctuations. The procedure establishes communications with the System Load Dispatcher immediately under such conditions and stresses that coordination with the System Load Dispatcher during degraded grid voltage/frequency conditions is imperative.

Maintaining unit/grid stability is also dependent upon generating unit MVAR output. BSEP plant procedures 1/2OP-27, "Generator and Exciter System Operating Procedure," direct operators to contact the System Load Dispatcher if generator MVAR loading cannot be maintained within prescribed limits.

In addition, the System Load Dispatcher is contacted in the event of severe weather conditions (i.e., 0AOP-13.0, "Operation During Hurricanes, Flood Conditions, Tornado, or Earthquake"), station blackout, (i.e., 0AOP-36.2, "Station Blackout"), or loss of DC power (i.e., 0AOP-39.0, "Loss of DC Power").

Transmission System Operations provides the BSEP with day-to-day direction regarding generator voltage schedules and MVAR output requirements. Control Room Operators monitor generator parameters and communicate with the dispatcher any operation outside the normal operating band. Operation and testing evolutions which have the potential to impact grid conditions are communicated to the System Load Dispatcher.

<u>Question 1(d)</u>

Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).

Response to Question 1(d)

Operators enter 0AOP-22.0 based on abnormal grid conditions indicated by changing system voltage or frequency. This procedure directs the operators to establish communication with the System Load Dispatcher. Coordination with the System Load Dispatcher during degraded grid voltage/frequency conditions is imperative. The System Load Dispatcher coordinates actions required by all Progress Energy plants and with other dispatchers to maintain stability and restore normal operation.

Responding to degraded grid conditions per 0AOP-22.0 is a core component of the initial and continuing licensed operator training programs. This includes both classroom and simulator training. Additional classroom training on degraded grid conditions is conducted during the Operating Experience lesson for loss of grid. This lesson plan is also a core component for initial and continuing licensed operator training programs.

Licensed operators are tested on their knowledge of 0AOP-22.0 requirements on exams during initial and continuing training when this topic is covered, and on comprehensive exams.

Degraded grid is an event in several core simulator scenarios for initial and continuing licensed operator training. These scenarios may be used for evaluation as well as training. Degraded grid is also included in some exam scenarios.

The Operating Experience lesson for loss of grid includes discussion of minimum and maximum generator MVAR limits specified by plant procedures 1/2OP-27 and Transmission System Operations procedure SORMC-GD-24, "System Operations Reference Manual Carolinas," including the reason for these limits. This lesson also discusses minimum and maximum switchyard voltage requirements, including the reason for these limits. This lesson plan is a core component for initial and continuing licensed operator training programs.

Question 1(e)

If you do not have a formal agreement or protocol with your TSO, describe why you believe you continue to comply with the provisions of GDC 17 as stated above, or describe what actions you intend to take to assure compliance with GDC 17.

Response to Question 1(e)

Not applicable, a formal agreement is used as described in response to Question 1(a).

Question 1(f)

If you have an existing formal interconnection agreement or protocol that ensures adequate communication and coordination between the NPP licensee and the TSO, describe whether this agreement or protocol requires that you be promptly notified when the conditions of the

surrounding grid could result in degraded voltage (i.e., below TS nominal trip setpoint value requirements; including NPP licensees using allowable value in its TSs) or LOOP after a trip of the reactor unit(s).

Response to Question 1(f)

Existing interface agreement requirements are implemented by the Transmission System Operators who monitor key grid parameters and use predictive analysis tools. The procedures used by the Transmission System Operators direct them to promptly notify BSEP of conditions for which there would not be adequate switchyard voltage, including predicted conditions resulting from a trip of a BSEP unit. Separate procedural steps are included to address both conditions which currently exist and conditions which are anticipated to occur. The intent of these separate steps is to provide as much warning as possible of the potential for problem conditions.

Question 1(g)

Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.

Response to Question 1(g)

BSEP degraded voltage protection is provided in accordance with Technical Specification 3.3.8.1, "Loss of Power (LOP) Instrumentation." Each 4.16 kV emergency bus has its own independent LOP instrumentation and associated trip logic. The voltage for each bus is monitored at two levels, which can be considered as two different undervoltage functions (i.e., 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) and 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)). The Technical Specification Allowable Values for these functions are as follows.

Function	Allowable Value
4.16 kV Emergency Bus Undervoltage (Loss of Voltage)	
a. Bus Undervoltage	≥ 3115 V and ≤ 3400 V
b. Time Delay	≥ 0.5 seconds and ≤ 2.0 seconds
4.16 kV Emergency Bus Undervoltage (Degraded Voltage)	
a. Bus Undervoltage	≥ 3706 V and ≤ 3748 V
b. Time Delay	≥ 9.0 seconds and ≤ 11.0 seconds

Should emergency bus voltage conditions satisfy the Allowable Value criteria, the Master/Slave breaker to the emergency bus will open and the associated diesel generator starts and loads. However, the minimum required switchyard voltage provided to the Transmission System

Operators to run the system is high enough to prevent degraded voltage conditions from occurring during post-trip load sequencing.

The required BSEP voltage and the post-trip load that will be connected to the grid are provided to the System Planning and Operations Department based on the minimum required switchyard voltage analyses documented and updated in calculation BNP-E-7.002 for BSEP. This calculation demonstrates the acceptability of the emergency bus degraded voltage relay setpoint in support of critical loads, and that the minimum required switchyard voltages used to operate the grid will not result in the BSEP disconnecting from offsite power during post trip load sequencing.

The minimum required switchyard voltage is then used to develop procedures for the Transmission System Operators to use day to day. Use of these procedures results in normal grid alignments that ensure the voltage limits are maintained.

NRC Question 2 Topic

Use of criteria and methodologies to assess whether the offsite power system will become inoperable as a result of a trip of your NPP.

Question 2(a)

Does your NPP's TSO use any analysis tools, an online analytical transmission system studies program, or other equivalent predictive methods to determine the grid conditions that would make the NPP offsite power system inoperable during various contingencies? If available to you, please provide a brief description of the analysis tool that is used by the TSO.

Response to Question 2(a)

Yes, the Transmission System Operators use procedures based on enveloping Transmission Planning analysis to operate the grid. As long as the grid configuration is within that allowed by the procedure under various system loading conditions, adequate post nuclear plant trip voltage support is assured. Specific case studies are also used, as necessary, to support planned grid configurations when not clearly bounded by existing studies. In addition to the transmission system analysis based procedures, the Transmission System Operators also use monitoring/predictive analysis computer programs that can predict nuclear plant switchyard voltages expected to occur upon realization of any one of a number of possible losses to the grid, such as a trip of the nuclear plant generator, a trip of another large generator, or the loss of an important transmission line. This monitoring/predictive analysis computer program tool operates based on raw data from transducers across the system which is processed through a state estimator to generate a current state snapshot of the system. The output is then processed through a contingency analysis program that generates a set of new results with various single elements of the system out of service. These results are then screened against a predetermined

set of acceptance limits. Postulated scenarios which then do not meet the acceptance limits are listed for review by the Transmission System Operator.

Question 2(b)

Does your NPP's TSO use an analysis tool as the basis for notifying the NPP licensee when such a condition is identified? If not, how does the TSO determine if conditions on the grid warrant NPP licensee notification?

Response to Question 2(b)

Yes, notifications are made based on grid configurations being outside of predefined procedure requirements or based on unsatisfactory monitoring/predictive analysis computer program tool results.

Question 2(c)

If your TSO uses an analysis tool, would the analysis tool identify a condition in which a trip of the NPP would result in switchyard voltages (immediate and/or long-term) falling below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and consequent actuation of plant degraded voltage protection? If not, discuss how such a condition would be identified on the grid.

Response to Question 2(c)

Yes, procedures and monitoring/predictive analysis tools are in place for this purpose.

Question 2(d)

If your TSO uses an analysis tool, how frequently does the analysis tool program update?

Response to Question 2(d)

The predictive analysis computer program updates every 10 minutes. Also, the grid operating procedures that are based on enveloping transmission system studies are updated as required by transmission system or plant changes.

Question 2(e)

Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.

Response to Question 2(e)

Analysis tool-identified contingency conditions would include an actual or anticipated grid configuration outside the bounds of the enveloping transmission system analysis based procedure requirements. In addition, monitoring/predictive analysis computer program validated results that do not meet the predetermined acceptance limit for minimum required switchyard voltage would also trigger a notification. The analyzed contingencies that are evaluated against the BSEP voltage requirements include: loss of another generator, loss of a significant transmission line, loss of a capacitor bank, or loss of the BSEP itself. If the BSEP voltage requirement cannot be met under any of the contingencies considered, BSEP will be notified. The same minimum required switchyard voltage limit bases that are used in the grid operating procedures are also used in the predictive analysis computer programs.

Question 2(f)

If an interface agreement exists between the TSO and the NPP licensee, does it require that the NPP licensee be notified of periods when the TSO is unable to determine if offsite power voltage and capacity could be inadequate? If so, how does the NPP licensee determine that the offsite power would remain operable when such a notification is received?

Response to Question 2(f)

Yes, if analysis tools are out of service to such an extent that system conditions are indeterminate, then implementing procedures used by the Transmission System Operators require notification to be made because a condition would exist where adequate voltage support capability for BSEP support is outside the guidelines of the current analysis. Upon such notification, BSEP will make an offsite power operability determination under the plant Technical Specifications. In addition, the System Operator will continue efforts to determine by alternate method(s) (e.g. offline study) if BSEP voltage requirements are satisfied or not.

Question 2(g)

After an unscheduled inadvertent trip of the NPP, are the resultant switchyard voltages verified by procedure to be bounded by the voltages predicted by the analysis tool?

Response to Question 2(g)

No, not by procedure. However, such analyses have been performed on a case-by-case basis to validate predicted results.

Question 2(h)

If an analysis tool is not available to the NPP licensee's TSO, do you know if there are any plans for the TSO to obtain one? If so, when?

Response to Question 2(h)

Not applicable, an analysis tool is available.

Question 2(i)

If an analysis tool is not available, does your TSO perform periodic studies to verify that adequate offsite power capability, including adequate NPP post-trip switchyard voltages (immediate and/or long-term), will be available to the NPP licensee over the projected timeframe of the study?

(a) Are the key assumptions and parameters of these periodic studies translated into TSO guidance to ensure that the transmission system is operated within the bounds of the analyses?

(b) If the bounds of the analyses are exceeded, does this condition trigger the notification provisions discussed in question 1 above?

Response to Question 2(i)

An analysis tool is available and the results of enveloping Transmission Planning analyses are incorporated into grid operating procedures. Additionally, grid operating procedures ensure that the configuration of the system is bounded by the analyses and notification is required if the configuration of the grid is not within the bounds of the procedures.

Question 2(j)

If your TSO does not use, or you do not have access to the results of an analysis tool, or your TSO does not perform and make available to you periodic studies that determine the adequacy of offsite power capability, please describe why you believe you comply with the provisions of GDC 17 as stated above, or describe what compensatory actions you intend to take to ensure that the offsite power system will be sufficiently reliable and remain operable with high probability following a trip of your NPP.

Response to Question 2(j)

Not applicable, a predictive analysis tool and enveloping transmission system studies are used.

NRC Question 3 Topic

Use of criteria and methodologies to assess whether the NPP's offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.

Question 3(a)

If the TSO notifies the NPP operator that a trip of the NPP, or the loss of the most critical transmission line or the largest supply to the grid would result in switchyard voltages (immediate and/or long-term) below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and would actuate plant degraded voltage protection, is the NPP offsite power system declared inoperable under the plant TSs? If not, why not?

Response to Question 3(a)

If an inadequate voltage condition is actually encountered or predicted to occur for a BSEP trip contingency, the Transmission System Operator will notify the BSEP and, per the requirements of plant procedures 1/2OP-50, "Plant Electric System Operating Procedure," offsite AC circuits will be declared inoperable and Condition E of Technical Specification 3.8.1 will be entered. Non-BSEP trip contingencies which have not actually occurred, such as the postulated loss of an important transmission line or other large generator, do not make offsite power inoperable. Should such an event actually occur, making voltage support inadequate, notification from the Transmission System Operator will be made and offsite power would then be declared inoperable.

Question 3(b)

If onsite safety-related equipment (e.g., emergency diesel generators or safety-related motors) is lost when subjected to a double sequencing (LOCA with delayed LOOP event) as a result of the anticipated system performance and is incapable of performing its safety functions as a result of responding to an emergency actuation signal during this condition, is the equipment considered inoperable? If not, why not?

Response to Question 3(b)

This question discusses the operability of equipment needed for mitigation of a Loss-of-Coolant Accident (LOCA) combined with delayed Loss of Offsite Power (LOOP). No formal plant specific evaluation of record exists for this scenario at BSEP. However, all BWRs have an inherent time delay for low pressure injection following a LOCA due to vessel depressurization. If a LOOP were to occur at the exact time that Emergency Core Cooling System (ECCS) injection flow was starting, the Emergency Diesel Generator (EDG) which is running as a result of the LOCA signal would connect to the emergency bus and then the ECCS loads would sequence back on. For BSEP, the specific licensing basis for LOCA analysis is described in the Updated Final Safety Analysis Report (UFSAR) Sections 15.0.3.2 and 15.6.4.1. The BSEP licensing basis requires that a complete loss of normal AC power occurs simultaneously with the pipe break. It does not require an assumption that a delayed LOOP occur.

Although the actual licensing basis analysis does not address a delayed LOOP, the potential consequences of a delayed injection have been generically considered by Boiling Water Reactor

Owners Group (BWROG) efforts associated with NRC Paper SECY-98-300, "Risk-Informed Revisions to 10 CFR Part 50 - Option 3." When evaluated using realistic methods, adequate protection was demonstrated in NEDO-33148, "Separation of Loss of Offsite Power From Large Break LOCA," for the BSEP class plant with injection delays up to 90 seconds for the EDG plus the valve stroke and pump start delays.

Based on the above, the proposed event is beyond the existing license requirements and no operability concerns exist. However, when evaluated using the methods of NEDO-33148, it is not anticipated that the postulated event would result in unacceptable results.

Question 3(c)

Describe your evaluation of onsite safety-related equipment to determine whether it will operate as designed during the condition described in question 3(b).

Response to Question 3(c)

As stated in response to Question 3(b), the BSEP licensing basis analysis does not require that a delayed LOOP be considered. However, based on generic efforts documented in NEDO-33148, it is not anticipated that the postulated event would result in unacceptable results.

Question 3(d)

If the NPP licensee is notified by the TSO of other grid conditions that may impair the capability or availability of offsite power, are any plant TS action statements entered? If so, please identify them.

Response to Question 3(d)

If BSEP is notified by the Transmission System Operator of grid conditions that may impair the capability or availability of offsite power, no Technical Specification Required Actions will be entered. As described in the Bases for Technical Specification 3.8.1, "AC Sources Operating," each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the emergency buses. If conditions exist that actually result in inadequate voltage, then appropriate Technical Specification Required Actions will be entered.

Question 3(e)

If you believe your plant TSs do not require you to declare your offsite power system or safety-related equipment inoperable in any of these circumstances, explain why you believe you comply with the provisions of GDC 17 and your plant TSs, or describe what compensatory actions you intend to take to ensure that the offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.

Response to Question 3(e)

Not applicable, if an inadequate voltage condition is actually encountered or predicted to occur for a BSEP trip contingency, appropriate Technical Specification Required Actions will be entered.

Question 3(f)

Describe if and how NPP operators are trained and tested on the compensatory actions mentioned in your answers to questions 3(a) through (e).

Response to Question 3(f)

Procedures require operators to declare offsite power sources inoperable and enter the Technical Specification action for two or more off-site circuits inoperable when notified by the load dispatcher that that the current grid supply/load conditions will not support a Unit trip, or that system conditions are inadequate to ensure emergency bus voltage support under LOCA conditions. These requirements are in the BSEP electric system operating procedures for both units (i.e., 1/2OP-50, "Plant Electric System Operating Procedure") and in the weekly breaker alignment surveillance (i.e., 0PT-12.6, "Breaker Alignment Surveillance").

Operators receive classroom instruction on conditions that constitute inoperability of offsite power sources during training on the 230 kV Distribution system. This system is a core topic of the initial and continuing licensed operating training programs. Additional classroom training is provided on the specific requirement to declare offsite power sources inoperable based on the load dispatcher notification that current grid supply/load conditions will not support unit trip or LOCA during the Operating Experience lesson for loss of grid. This lesson plan is also a core component for initial and continuing licensed operator training programs.

Operators receive simulator training on load dispatcher notification that current grid supply/load conditions will not support LOCA loading during performance of a simulator scenario involving degraded grid conditions. This scenario is a core scenario for the initial and continuing licensed operator training programs. This scenario may also be used for evaluation.

Licensed operators are subject to testing on operability of off-site sources on exams that cover this topic, and on comprehensive exams.

NRC Question 4 Topic

Use of criteria and methodologies to assess whether the offsite power system will remain operable following a trip of your NPP.

Question 4(a)

Do the NPP operators have any guidance or procedures in plant TS bases sections, the final safety analysis report, or plant procedures regarding situations in which the condition of plant-controlled or -monitored equipment (e.g., voltage regulators, auto tap changing transformers, capacitors, static VAR compensators, main generator voltage regulators) can adversely affect the operability of the NPP offsite power system? If so, describe how the operators are trained and tested on the guidance and procedures.

Response to Question 4(a)

Yes, the BSEP Technical Specification Bases, Section 3.8.1 contains the following guidance.

> A qualified offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling and controls required to transmit power from either 230 KV bus to the on site class 1 E emergency buses.

A detailed description of the offsite power network and circuits to the onsite class 1E emergency buses is found in the UFSAR, Sections 8.2 and 8.3. Routine screening of all deficiencies ensure that items have been appropriately dispositioned with respect to operability, and degraded or non-conforming conditions. Per OPS-NGGC-1305, "Operability Determinations," if operability can not be readily confirmed, or the item represents a potential degraded or non-conforming condition, a Nuclear Condition Report is initiated and prompt actions will be started to determine or verify operability.

Operators receive classroom instruction on conditions that constitute inoperability of off-site power sources during training on the 230KV Distribution system. Licensed operators are subject to testing on this information on exams covering this topic and on comprehensive exams.

Question 4(b)

If your TS bases sections, the final safety analysis report, and plant procedures do not provide guidance regarding situations in which the condition of plant-controlled or -monitored equipment can adversely affect the operability of the NPP offsite power system, explain why you believe you comply with the provisions of GDC 17 and the plant TSs, or describe what actions you intend to take to provide such guidance or procedures.

Response to Question 4(b)

Not applicable, suitable guidance is provided.

NRC Question 5 Topic

Performance of grid reliability evaluations as part of the maintenance risk assessments required by 10 CFR 50.65(a)(4).

Question 5(a)

Is a quantitative or qualitative grid reliability evaluation performed at your NPP as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4) before performing grid-risk-sensitive maintenance activities? This includes surveillances, post-maintenance testing, and preventive and corrective maintenance that could increase the probability of a plant trip or LOOP or impact LOOP or SBO coping capability, for example, before taking a risk-significant piece of equipment (such as an EDG, a battery, a steam-driven pump, an alternate AC power source) out-of-service?

Response to Question 5(a)

Yes, a blended approach to risk management, using both a quantitative and qualitative analysis of work activities prior to work authorization, including grid-risk-sensitive maintenance activities, is utilized at BSEP. Plant procedures 0AP-025, "BNP Integrated Scheduling," for online processes and 0AP-022, "BNP Outage Risk Management," for shutdown conditions are used in conjunction with Progress Energy procedures ADM-NGGC-0101, "Maintenance Rule Program," ADM-NGGC-0104, "Work Management Process," and ADM-NGGC-0006, "Online EOOS Models for Risk Assessment," control the processes in which risk assessments are performed and integrated into the daily work schedule.

0AP-025, Section 5.1, describes the activities completed during on-line schedule development, a subset being the development of weekly risk profiles. 0AP-025 Section 5.3 describes the management of risk sensitive activities.

0AP-22 Section 5.3 describes the defense in depth philosophy of scheduling during the outage time frame for the key safety function systems, one of those being electrical power distribution including offsite power sources.

Question 5(b)

Is grid status monitored by some means for the duration of the grid-risk-sensitive maintenance to confirm the continued validity of the risk assessment and is risk reassessed when warranted? If not, how is the risk assessed during grid-risk-sensitive maintenance?

Response to Question 5(b)

Yes, per the requirements of Progress Energy procedure NGGM-IA-0003, "Transmission Interface Agreement for Operation, Maintenance, and Engineering Activities at Nuclear Power

Plants," Section 6.2, Transmission System Operations and Nuclear Plant Operations are required to have daily and weekly communications to discuss the status of the plant and transmission system, upcoming work activities and operating conditions scheduled or anticipated for the next seven days. Section 6.6 and Section 7.8 of the agreement describe additional actions to be taken during an Emergent or Emergency Field Work condition, including the responsibilities and communications required. NGGM-IA-0003 clearly defines the requirements for communication of planned activities, and changes in plant status which may affect grid stability/reliability. Transmission System Operations is required to monitor system conditions to ensure adequate voltage is maintained to support each nuclear plant in the event of an accident, and promptly notify the Control Room Operators of existing, or anticipated conditions which would result in inadequate voltage support. BSEP plant procedure 0AP-025 provides the requirements associated with assessment of plant risk based on maintenance activities. This procedure requires a risk assessment prior to releasing on-line work as well as re-assessment of the potential risk associated with conducting the work if plant conditions do not remain within specified limits.

Question 5(c)

Is there a significant variation in the stress on the grid in the vicinity of your NPP site caused by seasonal loads or maintenance activities associated with critical transmission elements? Is there a seasonal variation (or the potential for a seasonal variation) in the LOOP frequency in the local transmission region? If the answer to either question is yes, discuss the time of year when the variations occur and their magnitude.

Response to Question 5(c)

Yes, the summer peak loads (i.e., July and August) as well as spring and fall maintenance outage activities result in variation in the stress on the capability of the grid to supply power. These variations are predictable, planned for, and managed. The magnitude of the variations results in less margin in the system to provide adequate voltage support. For this reason, additional analytical studies are used to ensure adequate voltage support is maintained during these periods. Seasonal variation regarding LOOP events is indicated below. However, these events were plant centered or severe weather related and not indicative of the reliability of the grid in the local transmission region.

Plant	Spring Mar. - May	Summer June - Aug.	Fall Sept. - Nov.	Winter Dec. - Feb.
BSEP 1	2	1*	1	0
BSEP 2	3*	1	0	0

* Three of the above events were due to severe weather. Two at Unit 2 in the spring and one at Unit 1 in the summer.

Question 5(d)

Are known time-related variations in the probability of a LOOP at your plant site considered in the grid-risk-sensitive maintenance evaluation? If not, what is your basis for not considering them?

Response to Question 5(d)

No, not based on the time of year. Variations in the probability of a LOOP are addressed based on notification protocols with the Transmission System Operator and local weather predictions regardless of the time of year. The grid around BSEP may experience higher grid loading during the summer and winter months. The Transmission System Operator evaluates current and forecasted load conditions and notifies Plant Nuclear Operations through the declaration of system contingency and reliability alerts. Per the requirements of 0AP-025, Section 5.3, activities are evaluated for risk and are either rescheduled or delayed. These alert levels are generally predictable in advance and are thus considered in weekly maintenance planning.

In addition, based on BSEP's location, seasonal trends that deal with uncertainties such as hurricanes or tornados are addressed by individuals performing risk assessments based on procedural guidance and work experience. 0AP-025, Section 5.7, discusses the issues of seasonal preparation.

Question 5(e)

Do you have contacts with the TSO to determine current and anticipated grid conditions as part of the grid reliability evaluation performed before conducting grid-risk-sensitive maintenance activities?

Response to Question 5(e)

Yes, per the requirements of Progress Energy procedure NGGM-IA-0003, Section 6.2, Transmission System Operations and Nuclear Plant Operations are required to have daily and weekly communications to discuss the status of the plant and transmission system, upcoming work activities and operating conditions scheduled or anticipated for the next seven days.

In addition a Plant Transmission Activities Coordinator (PTAC) is assigned at each Progress Energy nuclear plant. They are part of the Engineering organization and serve as a single point of contact between the various transmission departments and nuclear operations for planning, coordination, and oversight of transmission field work activities affecting the nuclear plant.

Also, Progress Energy procedure NGGM-IA-0003 is being revised to strengthen requirements associated with required communications between Transmission System Operations and Nuclear Plant Operations.

Question 5(f)

Describe any formal agreement or protocol that you have with your TSO to assure that you are promptly alerted to a worsening grid condition that may emerge during a maintenance activity.

Response to Question 5(f)

Interface agreements are in place to establish the interfaces between Transmission System Operations and the Nuclear Plant Operations. The agreements, along with the operating procedures used by the Transmission System Operators, ensure that early notification of worsening grid conditions take place. This occurs whether or not a specific maintenance activity is in progress at the plant.

With respect to potential grid problems which may be anticipated in advance, the agreement requires both daily and weekly communications between Nuclear Plant Operations and System Operations to discuss the status of the plant and the transmission system, review upcoming work activities, and discuss the operating conditions scheduled or anticipated for the next day and the next seven days. This communication provides a means for the grid and plant operators to know what is going on with each others systems.

With respect to potential grid problems which may occur with little or no advance warning, the Transmission System Operator is in a unique position to anticipate and assess grid problems via information obtained from: the grid Supervisory Control and Data Acquisition System (SCADA System), communications with field personnel, communications with neighboring utilities, and timely reports from various weather services. Implementing procedures require that Transmission System Operations monitor system conditions and promptly notify Nuclear Plant Operations of any existing or anticipated conditions which would result in inadequate voltage support.

Question 5(g)

Do you contact your TSO periodically for the duration of the grid-risk-sensitive maintenance activities?

Response to Question 5(g)

Yes, per the requirements of Progress Energy procedure NGGM-IA-0003, Transmission System Operations and Nuclear Plant Operations are required to have daily and weekly communications to discuss the status of the plant and transmission system, upcoming work activities and operating conditions scheduled or anticipated for the next seven days. In addition, NGGM-IA-0003 specifies the responsibilities, and lines of communication for the various organizations responsible for the operation, maintenance, and engineering of transmission facilities associated with BSEP, as well as the consideration of the impact their activities may have on the plant's transmission facilities. NGGM-IA-0003 clearly defines the requirements for

communication of planned activities, and changes in plant status which may affect grid stability/reliability. Transmission System Operations is required to monitor system conditions to ensure adequate voltage is maintained to support each nuclear plant in the event of an accident, and promptly notify the Control Room Operators of existing, or anticipated conditions which would result in inadequate voltage support. The Control Room is directed to notify Transmission System Operations of any plant activity that may impact generation capability.

Question 5(h)

If you have a formal agreement or protocol with your TSO, describe how NPP operators and maintenance personnel are trained and tested on this formal agreement or protocol.

Response to Question 5(h)

The Interface Agreement, NGGM-IA-0003, is discussed in System Description SD-50, "230 KV Distribution." SD-50 is a core component of the initial and continuing licensed operator training programs. The interface agreement is also covered during Operating Experience lesson for loss of grid. This lesson plan is also a core component for initial and continuing licensed operator training programs.

Implementation of the Interface Agreement is a daily activity for licensed operators and involves discussing the status of the plant and the transmission system and a review of upcoming work activities. Since this is a routine daily activity that involves nothing more than communication, there is no task on the licensed operator task list for this activity. Since there is no task associated with this activity, there are no objectives in the training program related to the Interface Agreement. Therefore operators are not tested on the Interface Agreement.

Transmission Maintenance personnel are responsible for maintenance on transmission lines, switchyard equipment (i.e., breakers and relaying), and transformers that supply offsite power into the plant. These personnel receive initial and annual refresher training in accordance with Section 11.2 of NGGM-IA-0003.

Question 5(i)

If your grid reliability evaluation, performed as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4), does not consider or rely on some arrangement for communication with the TSO, explain why you believe you comply with 10 CFR 50.65(a)(4).

Response to Question 5(i)

Not applicable, a grid reliability evaluation is performed as part of maintenance risk assessments at BSEP and arrangements are in place for communication with the Transmission System Operator.

Question 5(j)

If risk is not assessed (when warranted) based on continuing communication with the TSO throughout the duration of grid-risk-sensitive maintenance activities, explain why you believe you have effectively implemented the relevant provisions of the endorsed industry guidance associated with the maintenance rule.

Response to Question 5(j)

Not applicable, risk is assessed based on continuing communication with the Transmission System Operator throughout the duration of grid-risk-sensitive maintenance activities at BSEP.

Question 5(k)

With respect to questions 5(i) and 5(j), you may, as an alternative, describe what actions you intend to take to ensure that the increase in risk that may result from proposed grid-risk-sensitive activities is assessed before and during grid-risk-sensitive maintenance activities, respectively.

Response to Question 5(k)

Not applicable, BSEP does not intend to take any alternative actions.

NRC Question 6 Topic

Use of risk assessment results, including the results of grid reliability evaluations, in managing maintenance risk, as required by 10 CFR 50.65(a)(4).

Question 6(a)

Does the TSO coordinate transmission system maintenance activities that can have an impact on the NPP operation with the NPP operator?

Response to Question 6(a)

Yes, the Transmission System Operator coordinates transmission system maintenance activities that can have an impact on BSEP operation with Nuclear Plant Operations and the plant transmission activities coordinator (PTAC). NGGM-IA-0003 is the primary document which establishes this interface. The PTAC serves as the single point of contact for transmission engineering, construction, and maintenance activities impacting the nuclear plant. In addition, transmission system operators communicate directly with the nuclear plant operators regarding operational interfaces as described in the interface agreement.

Question 6(b)

Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?

Response to Question 6(b)

Yes, coordination of testing and maintenance activities at the plant that could affect electrical supply diversity is performed by the plant Outage and Scheduling organization and the PTAC, in accordance with NGGM-IA-0003. These activities are integrated into the online and outage scheduling processes per applicable site procedures. On line maintenance risk evaluations are performed for each work week as schedule changes occur. Safe shutdown risk assessments are also performed to evaluate each outage schedule prior to the outage. These reviews include representatives from the applicable Transmission Area Maintenance staff. This provides direct attention to transmission outage activities and aids in assessing their effects on defense in depth for electrical power supply.

Question 6(c)

Do you consider and implement, if warranted, the rescheduling of grid-risk-sensitive maintenance activities (activities that could (i) increase the likelihood of a plant trip, (ii) increase LOOP probability, or (iii) reduce LOOP or SBO coping capability) under existing, imminent, or worsening degraded grid reliability conditions?

Response to Question 6(c)

Yes. The Transmission System Operator communicates daily with Control Room Operations to discuss system conditions. Additionally, the Transmission System Operator notifies Control Room Operations if any preset conditions are met which would indicate challenges to grid reliability. The Transmission System Operator advises of potential challenges to grid stability/reliability. EDG and switchyard maintenance activities are not scheduled concurrently. Grid conditions are evaluated prior to authorizing work on an EDG or in the switchyard. Section 6.2 of NGGM-IA-0003 discusses the "day to day operations" responsibilities and communications between Transmission System Operations and the Control Room Operations. Section 7.2.8 describes our process for deferring previously scheduled work when needed.

Question 6(d)

If there is an overriding need to perform grid-risk-sensitive maintenance activities under existing or imminent conditions of degraded grid reliability, or continue grid-risk-sensitive maintenance when grid conditions worsen, do you implement appropriate risk management actions? If so, describe the actions that you would take. (These actions could include alternate equipment protection and compensatory measures to limit or minimize risk.)

Response to Question 6(d)

Yes, appropriate compensatory actions would be initiated by 0AP-025. From a qualitative and quantitative approach, BSEP would be in an elevated risk condition. Compensatory actions range from, but are not limited to:

- Pre-job briefs with round the clock coverage to minimize duration,
- Minimize work in other areas that could affect initiators or redundant systems,
- Parts/Materials staged, protected equipment barricaded or specific work areas assigned, and
- Designated lead personnel assigned with the use of mockups as necessary.

Question 6(e)

Describe the actions associated with questions 6(a) through 6(d) above that would be taken, state whether each action is governed by documented procedures and identify the procedures, and explain why these actions are effective and will be consistently accomplished.

Response to Question 6(e)

These actions are required by the Maintenance Rule processes implemented by procedure. Thus, the effectiveness and consistency is continually assessed and monitored. The interface agreement is the primary document which establishes the interfaces between the Transmission System Operators and the Nuclear Plant Operators. This agreement, along with the operating procedures used by the Transmission System Operators, ensures compliance. This agreement is binding in that it has been approved at the company Department level and periodic assessments are conducted to ensure compliance. In regards to identifying off-site power requirements, the importance of meeting these requirements, and recognizing that nuclear plants have high priority when restoring power, all of these attributes are included in the agreement and implemented as described.

Question 6(f)

Describe how NPP operators and maintenance personnel are trained and tested to assure they can accomplish the actions described in your answers to question 6(e).

Response to Question 6(f)

Operators receive classroom training on work management processes, including risk assessments using the lesson plan for Maintenance Documents. This lesson plan is a core component of the initial licensed operator training program.

Operators receive On the Job Training (OJT) on tasks associated with work management processes during their completion of their qualification cards. Once OJT is complete, they receive formal evaluation on these tasks by personnel performing Task Performance Evaluation (TPE).

The lesson plan for Maintenance Documents, and the tasks associated with the work management process are not selected as a core component of the licensed operator continuing training program because of the frequency of performance.

Transmission Maintenance personnel are responsible for maintenance on transmission lines, switchyard equipment (i.e., breakers and relaying), and transformers that supply off-site power into the plant. These personnel receive initial and annual refresher training in accordance with Section 11.2 of NGGM-IA-0003.

Question 6(g)

If there is no effective coordination between the NPP operator and the TSO regarding transmission system maintenance or NPP maintenance activities, please explain why you believe you comply with the provisions of 10 CFR 50.65(a)(4).

Response to Question 6(g)

Not applicable, coordination is directed by Interface Agreement NGGM-IA-0003, SORMC-GD-24, and 0AP-025.

Question 6(h)

If you do not consider and effectively implement appropriate risk management actions during the conditions described above, explain why you believe you effectively addressed the relevant provisions of the associated NRC-endorsed industry guidance.

Response to Question 6(h)

Not applicable, BSEP does effectively implement appropriate risk management actions per applicable procedures and the interface agreement.

Question 6(i)

You may, as an alternative to questions 6(g) and 6(h) describe what actions you intend to take to ensure that the increase in risk that may result from grid-risk-sensitive maintenance activities is managed in accordance with 10 CFR 50.65(a)(4).

Response to Question 6(i)

Not applicable, BSEP does not intend to take any alternative actions.

NRC Question 7 Topic

Procedures for identifying local power sources that could be made available to resupply your plant following a LOOP event.

Question 7(a)

Briefly describe any agreement made with the TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event.

Response to Question 7(a)

An agreement is in place to restore power to the Nuclear Plants as soon as possible. In addition, a Transmission System Operations procedure provides detailed instructions for prompt Nuclear Plant offsite power restoration. The procedure specifies various means of accomplishing the required power restoration. Transmission System Operators train on this procedure annually per NERC training requirements.

Question 7(b)

Are your NPP operators trained and tested on identifying and using local power sources to resupply your plant following a LOOP event? If so, describe how.

Response to Question 7(b)

Yes, while the Transmission System Operator is restoring offsite power using offsite power sources following a LOOP event, the immediate concern of the plant operator is to ensure power to the Emergency Buses from the onsite Emergency Diesel Generators (EDGs).

In the event both EDGs for one unit fail, the most significant requirement is to restore power to the Emergency Buses on the blacked out unit using available alternate AC power source(s) from the non-blacked out unit. This action consists of cross-tie of Emergency Buses between the blacked out and non-blacked out units. This cross-tie must be completed within one hour.

Training on the Station Blackout procedure, including Emergency Bus cross-tie, is a core component of the initial and continuing training programs for both licensed and non-licensed operators. For licensed operators this includes both classroom and simulator training. Cross-tie breaker operation is also covered in System Description SD-50.1, "4160 VAC Distribution," which is a core component of the initial and continuing training programs for both licensed and non-licensed operators

Operators are tested on their knowledge of Station Blackout requirements on exams during initial and continuing training when this topic is covered, and may be tested on this knowledge during comprehensive exams.

Operators receive On the Job Training (OJT) and Task Performance Evaluation (TPE) on tasks associated with Station Blackout as a part of the initial qualification process.

Job Performance Measures (JPMs) are written for tasks involving Emergency Bus cross-tie. These JPMs are often selected for use on annual operating exams for licensed and non-licensed operators.

Question 7(c)

If you have not established an agreement with your plant's TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event, explain why you believe you comply with the provisions of 10 CFR 50.63, or describe what actions you intend to take to establish compliance.

Response to Question 7(c)

Not applicable, the necessary agreement and implementing procedure are in place.

NRC Question 8 Topic

Maintaining SBO coping capabilities in accordance with 10 CFR 50.63.

Question 8(a)

Has your NPP experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63?

Response to Question 8(a)

No, based on a review of LOOP events at BSEP, a total LOOP event caused by grid failure has not occurred at BSEP since the Station Blackout (SBO) rule under 10CFR 50.63 was adopted.

Question 8(b)

If so, have you reevaluated the NPP using the guidance in Table 4 of RG 1.155 to determine if your NPP should be assigned to the P3 offsite power design characteristic group?

Response to Question 8(b)

Not applicable, see response to Question 8(a).

Question 8(c)

If so, what were the results of this reevaluation, and did the initially determined coping duration for the NPP need to be adjusted?

Response to Question 8(c)

Not applicable, see response to Question 8(a).

Question 8(d)

If your NPP has experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63 and has not been reevaluated using the guidance in Table 4 of RG 1.155, explain why you believe you comply with the provisions of 10 CFR 50.63 as stated above, or describe what actions you intend to take to ensure that the NPP maintains its SBO coping capabilities in accordance with 10 CFR 50.63.

Response to Question 8(d)

Not applicable, see response to Question 8(a).

Question 9

If you determine that any action is warranted to bring your NPP into compliance with NRC regulatory requirements, including TSs, GDC 17, 10 CFR 50.65(a)(4), 10 CFR 50.63, 10 CFR 55.59 or 10 CFR 50.120, describe the schedule for implementing it.

Response to Question 9

Not applicable, based upon the above responses, no additional action is required to bring BSEP into compliance with regulatory requirements regarding the topics included in this generic letter.

FPL

APR 0 1 2006

L-2006-037
10CFR50.4
10CFR 50.60(a)

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D. C. 20555

Subject: Turkey Point Units 3 and 4
Docket Nos. 50-250 and 50-25
Reactor Vessel Surveillance Capsule
Proposed Change in Withdrawal Schedule

This letter serves to inform the Nuclear Regulatory Commission (NRC) of Florida Power & Light Company's (FPL) intent to revise the Reactor Vessel Surveillance Program (RVSP) capsule withdrawal schedule for Turkey Point Units 3 and 4. NRC Administrative Letter 97-04, "NRC Staff Approval for Changes to 10 CFR Part 50, Appendix H, Reactor Vessel Surveillance Specimen Withdrawal Schedules," requires NRC review and verification that changes to the RVSP capsule withdrawal schedule meet the Standard ASTM E-185-82, "Standard Practice for Conducting Surveillance Tests for Light-water Cooled Nuclear Power Reactor Vessels, E 706 (IF)."

In accordance with 10 CFR 50.60(a), the attachment to this letter provides the necessary information for NRC review of and concurrence with the proposed surveillance capsule withdrawal schedule change. FPL requests NRC review and concurrence of the revised RVSP capsule withdrawal schedule by October 29, 2006, prior to the currently scheduled withdrawal date for Unit 4 capsule X, (capsule 4-X), during the Unit 4 Fall refueling outage.

The currently approved RVSP capsule withdrawal schedule is provided in Table 1. The proposed change to the integrated RVSP for Units 3 and 4 will revise the program to conform to the ASTM E-185-82 Standard. In accordance with ASTM E-185-82, Table 1, the recommended withdrawal schedule for the fifth capsule (capsule 4-X) is at the end of life (EOL) such that the surveillance capsule fluence is not less than once or greater than twice the peak EOL vessel fluence. EOL for Units 3 and 4 is 48 EFPY based on the renewed license expiration dates of 2032 and 2033 respectively. The revised EOL vessel fluence at the limiting weld is projected to be 3.93E19. FPL will revise the RVSP withdrawal schedule for the fifth capsule (capsule 4-X) from 24.0 effective full power years (EFPY) to 33.2 EFPY (from 2006 to 2015). The revised schedule will change the surveillance capsule target fluence from 3.85E19 to 5.89E19. A change to the surveillance capsule withdrawal schedule for capsule Unit 4-X is required to meet the EOL fluence requirements for the fifth capsule with the renewed license expiration dates. The proposed revised RVSP surveillance capsule withdrawal schedule is provided in Table 2.

Neutron fluence projections used to determine the revised withdrawal schedule for the fifth capsule (capsule 4-X) are obtained from calculations performed by Westinghouse as documented in Westinghouse report FPL-02-038, "Neutron Exposure Projections Based on Continued Use of Power Suppression Rods in Future Core Designs." The calculation results are provided in Attachment 1. The capsule 4-X neutron fluence projections are based on the same methodology used in the analysis for Unit 3 capsule X (capsule 3-X), documented in WCAP-15916, dated September 2002, and submitted to the NRC by FPL letter L-2002-199 dated October 8, 2002. The capsule 4-X analysis model included the use of part length Hafnium absorbers in the core, which is the current Turkey Point fuel management philosophy. The calculated lead factor and projected neutron fluence assume a 95% capacity factor. The capsule 3-X measured fluence was used as an approximation of the capsule 4-X fluence since they both had approximately the same EFPY at the time of capsule 3-X withdrawal on September 21, 2001.

By letter dated April 22, 1985, the NRC approved an integrated surveillance program for Turkey Point Units 3 and 4. Changing the withdrawal schedule for the fifth capsule (capsule 4-X) does not have any impact on the Turkey Point Units 3 and 4 integrated surveillance program. The mechanical property data requirements for an integrated surveillance program have been met by data obtained from surveillance capsules T-3, T-4, V-3 and X-3. Additional mechanical property data is available from surveillance capsule A5 which contained Turkey Point material and was irradiated and tested in 1999 as part of the B&W Reactor Vessel Owners Group program. In addition, there are two supplemental capsules containing Turkey Point weld metal: 1) surveillance capsule A2 being irradiated at Crystal River as part of the B&WOG Master Integrated Surveillance Program; and 2) a capsule that has recently been installed at Point Beach. Dosimetry data from capsule 4-X is not required to validate the model used to calculate the neutron exposure. As documented in FPL letter L-2002-199, comparisons of the measured dosimetry results to both the calculated and least squares adjusted values for all surveillance capsules withdrawn from service through 2001 at Turkey Point Unit 3 met the acceptance criteria specified by Regulatory Guide 1.190, and therefore, validated the model used to calculate the neutron exposures.

Please contact Walter Parker at (305) 246-6632, if there are any questions.

Very truly yours,

Terry Jones

Terry O. Jones
Vice President
Turkey Point Nuclear Plant

cc: Regional Administrator, Region II, USNRC
Senior Resident Inspector, USNRC, Turkey Point

Table 1
Surveillance Capsule Withdrawal Schedule
For Turkey Point Units 3 & 4

Capsule(d)	Capsule Location (Degree)	Updated Lead Factor	Removal EFPY(a)	Capsule Fluence (n/cm^2)
T_3(b)	270	2.60	1.15	7.39×10^{18}
T_4(b)	270	2.48	1.17	7.08×10^{18}
S_4(b)	280	1.60	3.41	1.43×10^{19}
S_3(b)	280	1.96	3.46	1.72×10^{19}
V_3(b)	290	0.75	8.06	1.53×10^{19}
X_3(c)	270	2.48	19.4 (29 years)	*2.74×10^{19}
X_4(c)	270	2.48	24.0 (34 years)	*3.85×10^{19}
Y_3	150	0.49	Standby	-----
U_3	30	0.49	Standby	-----
W_3	40	0.34	Standby	-----
Z_3	230	0.34	Standby	-----
V_4	290	0.79	Standby	-----
Y_4	150	0.49	Standby	-----
U_4	30	0.49	Standby	-----
W_4	40	0.34	Standby	-----
Z_4	230	0.34	Standby	-----

NOTES:

(a) Effective Full Power Years (EFPY) from plant startup.
(b) Plant specific evaluation.
(c) Since the vessel controlling material is the weld metal, and only Capsule V from Unit 4 and Capsules X from Units 3 and 4 contain weld specimens, Capsule X in Units 3 and 4 were moved to the 270° location to increase the lead factor.
(d) Unit designation shown in subscript.
* Projected.

Table 2

**Proposed Revised Surveillance Capsule Withdrawal Schedule
Turkey Point Units 3 & 4**

Capsule (Unit shown as subscript)	Capsule Location (Degree)	Updated Lead Factor	Removal EFPY (a)	Capsule Fluence (n/cm^2)
T_3	270	2.60	1.15	7.39×10^{18} (e)
T_4	270	2.48	1.17	7.08×10^{18} (e)
S_3	280	1.96	3.46	1.72×10^{19} (e)
S_4	280	1.60	3.41	1.43×10^{19} (e)
V_3	290	0.75	8.06	1.53×10^{19} (e)
X_3	270 (50)(b)	2.48	19.85	2.93×10^{19} (e)
X_4	270 (50)(b)	3.43(d)	33.2	5.89×10^{19} (c)
V_4	290	0.79	Standby	--
U_3	30	0.49	Standby	--
U_4	30	0.49	Standby	--
W_3	40	0.34	Standby	--
W_4	40	0.34	Standby	--
Y_3	150	0.49	Standby	--
Y_4	150	0.49	Standby	--
Z_3	230	0.34	Standby	--
Z_4	230	0.34	Standby	--

(a) Effective Full Power Years.
(b) The "X" capsules were moved from the 50 degree location to the 270 degree location in 1990.
(c) Projected 1.5 times EOL fluence for the limiting weld material.
(d) Based on future fluence only and only associated with limiting weld material.
(e) Fluence is measured.

**ATTACHMENT 1 TO
L-2006-037**

Westinghouse

Westinghouse Electric Company
Nuclear Services
P.O. Box 355
Pittsburgh, Pennsylvania 15230-0355
USA

Mr. Andy Zielonka
Florida Power & Light Company
Turkey Point Nuclear Plant
9760 S.W. 344th Street
Florida City, FL 33035

Our ref: FPL-02-38

October 16, 2002

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT UNIT 3
Neutron Exposure Projections Based on
Continued Use of Power Suppression Rods in Future Core Designs

References:
1. FPL Purchase Order No. 00053832, Rev. 001
2. Westinghouse Sales Order No. 12928
3. Westinghouse Letter FPL-02-30, 9/20/02, "Reactor Vessel Surveillance Capsule Analysis Final Report Transmittal
4. LTR-REA-02-101

Dear Mr. Zielonka:

Pursuant to the add-on scope of work (Ref. 1), obtained by Westinghouse that resulted from the recently completed Turkey Point Unit 3 Capsule X analysis documented in WCAP-15916 (Ref. 3), an additional set of neutron exposure projections for the surveillance capsule locations and reactor pressure vessel, including critical girth weld, are attached. It should be noted that the projections in WCAP-15916 are conservatively based on the assumption that part-length absorbers utilized in assemblies on the core flats will be discontinued in the future. In contrast, the attached projections assume that these power suppression rods will be used in the future. Thus, following the end of the current operating Cycle 19, the attached projections are based on the burnup-weighted average core design data from the last two fuel reloads that utilized these power suppression devices, i.e., Cycles 18 and 19. In addition, these projections assume that the current reactor power level of 2300 MWt will be maintained.

The attached tables provide neutron exposure values in terms of fast (E > 1.0 MeV) neutron flux/fluence and iron atom displacement rates/displacements (dpa) calculated for the Turkey Point Unit 3 surveillance capsules, maximum values for the reactor pressure vessel at the clad/base metal interface, and maximum values for the critical girth weld (located between the intermediate shell course and lower shell course vessel forgings) at the clad/base metal interface. The calculational methodology previously described in WCAP-15916, was also used to support

this work and satisfies the requirements specified in Regulatory Guide RG-1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," dated March 2001.

In addition, please find attached a Westinghouse Certification of Conformance for the work performed and transmitted by the Ref. 3 letter.

If you have any questions regarding this transmittal, please call Tom Laubham at 412-374-6788 or Mike Miler at 412-374-3353.

Sincerely,

WESTINGHOUSE ELECTRIC COMPANY LLC

Michael J. Miller / for

Douglas H. Warren
Customer Projects Manager

Attachments

cc: Steve Collard 1L, 1A

Table 1

Summary of Calculated Neutron Exposure Rates and Integrated Exposures
At The Surveillance Capsule Center
(Centered at the Core Midplane)

Fuel Cycle	Irradiation Time [efpy]	Neutron Flux (E > 1.0 MeV) [n/cm^2-s]				
		0°	10°	20°	30°	40°
Cycle 19	21.16	7.64E+10	5.92E+10	3.65E+10	2.94E+10	2.02E+10
Future	32.00	7.03E+10	5.58E+10	3.79E+10	3.04E+10	2.05E+10
Future	48.00	7.03E+10	5.58E+10	3.79E+10	3.04E+10	2.05E+10
Future	54.00	7.03E+10	5.58E+10	3.79E+10	3.04E+10	2.05E+10

Fuel Cycle	Irradiation Time [efpy]	Neutron Fluence (E > 1.0 MeV) [n/cm^2]				
		0°	10°	20°	30°	40°
EOC 19	21.16	6.82E+19	5.11E+19	2.81E+19	2.16E+19	1.47E+19
Future	32.00	9.22E+19	7.02E+19	4.10E+19	3.20E+19	2.17E+19
Future	48.00	1.28E+20	9.84E+19	6.02E+19	4.73E+19	3.20E+19
Future	54.00	1.41E+20	1.09E+20	6.74E+19	5.31E+19	3.59E+19

Fuel Cycle	Irradiation Time [efpy]	Iron Atom Displacement Rate [dpa/s]				
		0°	10°	20°	30°	40°
Cycle 19	21.16	1.28E-10	1.00E-10	5.94E-11	4.80E-11	3.27E-11
Future	32.00	1.18E-10	9.44E-11	6.17E-11	4.97E-11	3.31E-11
Future	48.00	1.18E-10	9.44E-11	6.17E-11	4.97E-11	3.31E-11
Future	54.00	1.18E-10	9.44E-11	6.17E-11	4.97E-11	3.31E-11

Fuel Cycle	Irradiation Time [efpy]	Iron Atom Displacements [dpa]				
		0°	10°	20°	30°	40°
EOC 19	21.16	1.15E-01	8.68E-02	4.58E-02	3.53E-02	2.37E-02
Future	32.00	1.55E-01	1.19E-01	6.69E-02	5.23E-02	3.50E-02
Future	48.00	2.15E-01	1.67E-01	9.80E-02	7.74E-02	5.17E-02
Future	54.00	2.37E-01	1.85E-01	1.10E-01	8.68E-02	5.80E-02

Table 2

Summary of Calculated Maximum Neutron Exposure Rates and Integrated Exposures
At The Pressure Vessel Clad/Base Metal Interface

Fuel Cycle	Irradiation Time [efpy]	Neutron Flux (E > 1.0 MeV) [n/cm²-s]			
		0°	15°	30°	45°
Cycle 19	21.16	3.43E+10	1.86E+10	1.16E+10	7.84E+09
Future	32.00	3.17E+10	1.84E+10	1.20E+10	7.94E+09
Future	48.00	3.17E+10	1.84E+10	1.20E+10	7.94E+09
Future	54.00	3.17E+10	1.84E+10	1.20E+10	7.94E+09

Fuel Cycle	Irradiation Time [efpy]	Neutron Fluence (E > 1.0 MeV) [n/cm²]			
		0°	15°	30°	45°
EOC 19	21.16	2.76E+19	1.42E+19	8.54E+18	5.67E+18
Future	32.00	3.85E+19	2.05E+19	1.26E+19	8.39E+18
Future	48.00	5.45E+19	2.97E+19	1.87E+19	1.24E+19
Future	54.00	6.04E+19	3.32E+19	2.10E+19	1.39E+19

Fuel Cycle	Irradiation Time [efpy]	Iron Atom Displacement Rate [dpa/s]			
		0°	15°	30°	45°
Cycle 19	21.16	5.89E-11	3.07E-11	1.96E-11	1.28E-11
Future	32.00	5.44E-11	3.03E-11	2.03E-11	1.30E-11
Future	48.00	5.44E-11	3.03E-11	2.03E-11	1.30E-11
Future	54.00	5.44E-11	3.03E-11	2.03E-11	1.30E-11

Fuel Cycle	Irradiation Time [efpy]	Iron Atom Displacements [dpa]			
		0°	15°	30°	45°
EOC 19	21.16	4.75E-02	2.35E-02	1.45E-02	9.28E-03
Future	32.00	6.61E-02	3.38E-02	2.14E-02	1.37E-02
Future	48.00	9.36E-02	4.91E-02	3.17E-02	2.03E-02
Future	54.00	1.04E-01	5.48E-02	3.55E-02	2.27E-02

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Table 3

Summary of Calculated Maximum Neutron Exposure Rates and Integrated Exposures
At The Intermediate Shell Course to Lower Shell Course Girth Weld Clad/Base Metal Interface

Fuel Cycle	Irradiation Time [efpy]	Neutron Flux (E > 1.0 MeV) [n/cm^2-s]			
		0°	15°	30°	45°
Cycle 19	21.16	2.22E+10	1.46E+10	1.10E+10	7.49E+09
Future	32.00	2.05E+10	1.47E+10	1.15E+10	7.62E+09
Future	48.00	2.05E+10	1.47E+10	1.15E+10	7.62E+09
Future	54.00	2.05E+10	1.47E+10	1.15E+10	7.62E+09

Fuel Cycle	Irradiation Time [efpy]	Neutron Fluence (E > 1.0 MeV) [n/cm^2]			
		0°	15°	30°	45°
EOC 19	21.16	2.19E+19	1.25E+19	8.15E+18	5.48E+18
Future	32.00	2.89E+19	1.75E+19	1.21E+19	8.08E+18
Future	48.00	3.93E+19	2.49E+19	1.79E+19	1.19E+19
Future	54.00	4.31E+19	2.77E+19	2.00E+19	1.34E+19

Fuel Cycle	Irradiation Time [efpy]	Iron Atom Displacement Rate [dpa/s]			
		0°	15°	30°	45°
Cycle 19	21.16	3.84E-11	2.42E-11	1.87E-11	1.23E-11
Future	32.00	3.54E-11	2.42E-11	1.95E-11	1.25E-11
Future	48.00	3.54E-11	2.42E-11	1.95E-11	1.25E-11
Future	54.00	3.54E-11	2.42E-11	1.95E-11	1.25E-11

Fuel Cycle	Irradiation Time [efpy]	Iron Atom Displacements [dpa]			
		0°	15°	30°	45°
EOC 19	21.16	3.79E-02	2.07E-02	1.39E-02	8.98E-03
Future	32.00	5.00E-02	2.90E-02	2.05E-02	1.33E-02
Future	48.00	6.79E-02	4.12E-02	3.04E-02	1.96E-02
Future	54.00	7.46E-02	4.58E-02	3.40E-02	2.19E-02