Florida Power & Light, 9760 S.W. 344 ST. Florida City, FL 33034

FPL.

APR 1 4 2011
L-2011-101
10 CFR 50.90

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D. C. 20555-0001

Re: Turkey Point Units 3 and 4
Docket Nos. 50-250 and 50-251
Response to NRC Request for Additional Information Regarding
Extended Power Uprate License Amendment Request No. 205 and
Balance of Plant Issues

References:

(1) M. Kiley (FPL) to U.S. Nuclear Regulatory Commission (L-2010-113), "License Amendment Request No. 205: Extended Power Uprate (EPU)," (TAC Nos. ME4907 and ME4908), Accession No. ML103560169, October 21, 2010.

(2) Email from J. Paige (NRC) to T. Abbatiello (FPL), "Turkey Point EPU – Balance of Plant (SBPB) Request for Additional Information - Round 1," Accession No. ML110770196, March 18, 2011.

By letter L-2010-113 dated October 21, 2010 [Reference 1], Florida Power and Light Company (FPL) requested to amend Renewed Facility Operating Licenses DPR-31 and DPR-41 and revise the Turkey Point Units 3 and 4 Technical Specifications (TS). The proposed amendment will increase each unit's licensed core power level from 2300 megawatts thermal (MWt) to 2644 MWt and revise the Renewed Facility Operating Licenses and TS to support operation at this increased core thermal power level. This represents an approximate increase of 15% and is therefore considered an extended power uprate (EPU).

By email from the U.S. Nuclear Regulatory Commission (NRC) Project Manager (PM) dated March 18, 2011 [Reference 2], additional information regarding Balance of Plant issues was requested by the NRC staff in the Balance of Plant Branch (SBPB) to support their review of the EPU License Amendment Request (LAR). The Request for Additional Information (RAI) consisted of six (6) questions regarding missile protection, component cooling water heat exchanger fouling, ultimate heat sink capacity, and large plant transient testing. These six RAI questions and the FPL responses are documented in the Attachment to this letter.

In accordance with 10 CFR 50.91(b)(1), a copy of this letter is being forwarded to the State Designee of Florida.

This submittal does not alter the significant hazards consideration or environmental assessment previously submitted by FPL letter L-2010-113 [Reference 1].

This submittal contains no new commitments and no revisions to existing commitments.

Should you have any questions regarding this submittal, please contact Mr. Robert J. Tomonto, Licensing Manager, at (305) 246-7327.

A001
NRR

I declare under penalty of perjury that the foregoing is true and correct.

Executed on April 14, 2011.

Very truly yours,

Michael Kiley
Site Vice President
Turkey Point Nuclear Plant

Attachment

cc: USNRC Regional Administrator, Region II
USNRC Project Manager, Turkey Point Nuclear Plant
USNRC Resident Inspector, Turkey Point Nuclear Plant
Mr. W. A. Passetti, Florida Department of Health

Turkey Point Units 3 and 4

RESPONSE TO NRC RAI REGARDING EPU LAR NO. 205
AND BALANCE OF PLANT (SBPB) ISSUES

ATTACHMENT

Response to Request for Additional Information

The following information is provided by Florida Power and Light Company (FPL) in response to the U. S. Nuclear Regulatory Commission's (NRC) Request for Additional Information (RAI). This information was requested to support License Amendment Request (LAR) No. 205, Extended Power Uprate (EPU), for Turkey Point Nuclear Plant (PTN) Units 3 and 4 that was submitted to the NRC by FPL letter L-2010-113 on October 21, 2010 [Reference 1].

In an email dated March 18, 2011 [Reference 2], the NRC staff requested additional information regarding FPL's request to implement the EPU. The RAI consisted of six questions from the NRC Balance of Plant (BOP) Branch regarding missile protection, component cooling water heat exchanger fouling, ultimate heat sink capacity, and large plant transient testing. These six RAI questions and the FPL responses are documented below.

SBPB-1.1 Section 2.5.1.2.2 of Attachment 4 to the license amendment request dated October 21, 2010, described protection against potential missiles originating from the turbine generator. Section 10.2.2, "Design Features – Turbine Controls," and Section 14.1.13, "Turbine Generator Design Analysis," of the Turkey Point Updated Final Safety Analysis Report (UFSAR) provided a description of the turbine control system, overspeed protective features, and turbine construction. In Supplements 3 and 8 to the preliminary safety analysis report, Florida Power & Light Company (FPL) discussed the potential for turbine missiles in response to AEC questions. Results of the turbine failure analysis indicated that due to the reliability and redundancy of the turbine overspeed protection system, the probability of turbine overspeed above the design value would be low.

Section 2.5.1.2.2.2.2 of Attachment 4 to the license amendment request specified that the following acceptance criteria would be pertinent to the Turkey Point Units 3 and 4 Turbine-Generator:

- **The calculated overspeed at EPU conditions shall be less than the design overspeed value of 120%**
- **The probability of generating a turbine missile shall remain below the NRC guideline of 1×10^{-5} per year.**

Although Attachment 4 included a list of considerations, the method of verifying that these acceptance criteria would be satisfied at EPU conditions was not specified. Describe how FPL determined the probability of generating a turbine missile will remain below the NRC acceptance criteria of 1 x 10-5 per year at EPU conditions.

<u>Response – 1.1 Part a.:</u>

The calculation of maximum overspeed values was performed by the turbine

Original Equipment Manufacturer in accordance with the calculation methodology outlined in ASME PTC 20.2. All calculations were performed using EPU thermal conditions. This methodology takes into account:

- Performance and efficiency characteristic of the upgraded combined high pressure (HP) and low pressure (LP) turbine
- Rotating inertia of the turbine-generator unit as upgraded for EPU
- Overspeed trip setpoint
- Entrained energy contributing to speed increase, which is a function of:
    - Volume and energy of entrapped steam and water, including all planned modifications (includes replacement feedwater heaters and the moisture separator reheater (MSR)) to the entrapped steam volume for EPU (both internal and external to the turbine), and evaluated including the worst case single extraction steam non-return valve failure
    - Closing times for isolation of the steam supply through both the main steam stop valves and MSR to LP inlet intercept valves

The base evaluation generates an expected turbine overspeed based (in this case) on tripping at the existing mechanical overspeed trip setpoint, and the entrained energy contained in the turbine train itself.

Once the base evaluation is complete, a series of sensitivities is generated based on the thermal conditions of the entrapped steam and water volumes in each of the feedwater heaters. These sensitivities are in the form of percent overspeed per 1000 cubic feet of steam or 100 cubic feet of water. The worst case is then selected based on the product of the percent overspeed and the entrapped volumes to yield the maximum overspeed occurring for failures of each of the extraction non-return valves.

Once the described process is performed, the overspeed calculated is compared to the 120% design overspeed of the unit. For EPU, the increase in rotating inertia of the HP turbine and generator partially offsets the increase in energy contributing to overspeed. This results in only a small increase in the maximum potential overspeed at EPU. Since the 120 % design overspeed of the unit is not exceeded, the overspeed trip setpoint does not require a corresponding reduction to prevent the design overspeed from being reached, thus remaining within the design overspeed limit of 120%.

Since the design (120%) overspeed is not exceeded at EPU conditions and all replacement train components are spin-tested to this speed as verification of mechanical integrity during the factory rotor balance process, the design overspeed point is demonstrated to be bounding.

HP rotor missile ejection at design overspeed is not a viable risk for modern monoblock rotor construction. Since the LP rotors are not being altered for EPU, and the changes in LP turbine steam conditions are negligible with respect to parameters related to missile generation, there is no change to the EPU LP rotor missile generation risk at design (120%) overspeed.

Response – 1.1 Part b.:

The probability of generating an external turbine rotor missile (P1) is given below:

P1 = Pr + Po + Pi + Pd; where:

- Pr = probability of a missile at running (or rated) speed
- Po = probability of a missile at design overspeed (> rated speed, ≤ 120% of rated speed)
- Pi = probability of a missile at intermediate overspeed (> 120%, ≤ ~130% of rated speed)
- Pd = probability of a missile at destructive overspeed (> ~130% of rated speed)

The probability of "Pr" (the probability of generating a missile at running speed), given that the current inspection and test frequency will be unchanged following implementation, is bounded in this case by "Po" (the probability of missile generation at design overspeed), which is unchanged in this case as addressed in Part 1.1 Part a. above.

Term "Pi" relates to the failure of intercept valves to isolate the MSR volume from the LP turbine. In this case, since the valves are unchanged, changes related to the control and trip systems are the only elements of the system that have an effect on this probability.

Term "Pd" is the other consideration for the probability of missile generation potentially affected by EPU, and is also governed by changes to the control and trip system as discussed below.

Since the speed required for either the original or replacement HP turbine rotor burst is greater than that of the LP rotors, LP rotors are the limiting component for destructive overspeed. Additionally, since the LP rotors, operating conditions (as related to overspeed failure), and inspection intervals are unchanged at uprate, the only remaining factor for this evaluation is the probability of reaching destructive overspeed.

In order to reach destructive overspeed, the turbine control system and overspeed protection systems must fail. The design of these systems and their reliability dictate their failure probability.

The current turbine control valve inspection and test frequency will be unchanged at EPU conditions. The valves will be modified at uprate to allow additional valve travel, however, the basic valve design and operation is unchanged.

As stated in the LAR Section 2.5.1.2.2, the existing analog control system is being replaced at EPU with a digital turbine control system (TCS). In addition, the turbine hydraulic control system is being replaced with the standard Siemens EHC system with the exception of the mechanical overspeed trip system which is being removed and replaced with an independent electric system.

Theses changes impact the probability of destructive overspeed since the turbine control system and overspeed protective devices probability may change. For EPU, these changes will drive any differences in this probability from the existing analysis.

To evaluate the change in the failure probability of the control systems, the EPU design for the control and overspeed protection systems were reviewed against the designs for plants with the similar digital electro hydraulic control (DEHC) and turbine/valve configurations to the EPU design since the entire control and hydraulic system will be replaced under EPU. The current Turkey Point turbine missile ejection frequency for destructive overspeed is 9.0×10^{-7}/year (6 month test interval). The Turkey Point EPU turbine control systems will be similar to H.B. Robinson which has the same destructive overspeed missile ejection frequency and Shearon Harris which has a destructive overspeed missile ejection frequency of less than 9.0×10^{-7}/year (6 month test interval). The evaluation considered fault tree changes, reliability data for new system components, system redundancy, and other parameters critical to the analysis.

The results of the evaluation showed that the new Turkey Point turbine control system provide increased reliability over the bench mark plants since:

1. The Turkey Point turbine digital control system will have redundancy features that do not exist in the bench mark plants for speed detection and micro processors/power supply/input channels redundancy.
2. Turkey Point EPU will remove the single active mechanical overspeed device and replace it with a diverse (separate from TCS) fail safe digital control system that has 3 redundant detection channels.
3. The Turkey Point EHC system will use the same standard Siemens 6 solenoid trip block as Shearon Harris which is also more reliable than H.B. Robinson design since it has greater redundancy.

Therefore, the probability of failure for the replacement system should be bounded by the probability of the bench mark plants and the overall yearly probability of turbine missile generation will not exceed the 1×10^{-5} per year criteria of SRP Section 3.5.1.3.

SBPB-1.2 **Section 2.5.1.3 of Attachment 4 to the license amendment request includes the following statement regarding the effect of changes in main feedwater operating conditions on the effects of postulated high energy line breaks:**

> **Main Feedwater System operating temperature has increased slightly due to the EPU while the previous pressure assumptions bound EPU operating conditions. Additionally, the replacement of the 6th Feedwater Heaters will result in resizing of the discharge piping from 18 inches to 24 inches. As a result, the jet impingement zones of influence are increasing due to EPU.**

Explain the general methodology and assumptions used to determine jet impingement zones of influence. Clarify the relative effects of the temperature change and the discharge piping change on the zones of influence defined for the postulate breaks in the feedwater system at EPU conditions.

Zones of influence can be established based on temperature limits, absolute impingement pressure limits, and/or target damage threshold considerations. In order to determine the potential impact of EPU conditions near the outlet nozzles of feedwater heaters 6A and 6B on each unit, walkdowns were performed assuming that the zone of influence increased in proportion to the increase in size of the outlet nozzle diameter from 18" to 24" nominal. The walkdowns utilized a zone of influence with a radius equal to 10 pipe diameters (internal pipe diameter). The walkdowns identified certain components that could potentially be influenced by their proximity to the zone of influence. At this point, a conservative decision was made to install shields at each outlet nozzle in lieu of evaluating the identified components for adverse consequences from varied impingement effects. The shields are designed to redirect flow from the postulated break location and associated impingement effects in a direction that precludes adverse impact on the safety related items. Additional details on the evaluations and the shields being installed to protect equipment important to safety from the effects of this postulated break are provided in the PTN responses to Mechanical and Civil Branch (EMCB) Acceptance Review question 3. The response for Turkey Point Unit 3 is provided in Reference 3. The response for Unit 4 will be provided by April 30.

With the exception of the number six feedwater heater outlet break locations, sleeves combined with whipping restraints are currently installed at feedwater system break locations to protect any surrounding safety-related components from the effects of high energy line breaks. The sleeves are designed to withstand the jet forces and the internal pressurization resulting from the escape of high energy fluid. The whipping restraints are designed to restrict pipe axial displacement and motion within the sleeve following a postulated circumferential pipe break.

EPU conditions will only increase the temperature of the feedwater system from between 0.1°F to 0.9°F at the break locations. This will have a marginal impact on the existing analyses.

SBPB-1.3 **Section 2.5.4.3 of Attachment 4 to the license amendment request explains that the intake cooling water salinity would increase at EPU conditions and that the maximum analyzed post-accident component cooling water (CCW) temperature would increase from 150°F to 157.8°F for EPU. This section also includes the following statement:**

> **The computer software, operability curves, and manual calculations used to verify heat exchanger operability, updated to reflect higher design basis accident heat loads at EPU and the effects on water properties due to increased salinity in the ICW water, will continue to ensure that the CCW heat exchangers will remain reliable and operable after the uprate.**

Table 2.5.4.3-3, "CCW System Thermal Analysis Parameters for Postulated Accident," indicates a lower total tube heat transfer resistance would be assumed for EPU analyses (0.00285 °F-hr-ft^2/Btu) than was used for current analyses (0.0030 °F-hr-ft^2/Btu).

Explain how the effects of higher temperatures and salinity were considered with respect to potential increased fouling from calcium scale formation on the CCW heat exchanger tubes.

The effects of calcium carbonate precipitation only need to be considered for the Intake Cooling Water (ICW) which is on the tube side of the CCW heat exchangers. The peak ICW outlet temperature from the CCW heat exchangers for the EPU case will increase commensurately with CCW temperature. The shell side of the CCW heat exchangers is demineralized water.

The effects of higher temperature on the formation of calcium scale on ICW that are expected at EPU were evaluated using the Langelier Saturation Index (LSI). This index is a method used to predict whether calcium carbonate will precipitate, dissolve, or be in equilibrium with water. The inputs to the LSI evaluation considered the effects of pH, water temperature, calcium concentration, Total Dissolved Solids (TDS) and alkalinity. The evaluation compared the LSI values between pre- and post-EPU for normal and accident modes of operation. Salinity has no direct impact on the formation of calcium scale in the LSI.

The CCW temperature increase above 150°F to 157.8°F due to EPU only occurs for approximately four hours during the early stages of an accident. Due to this relatively brief period of time, no significant change in calcium scale formation is expected due to this increase in CCW temperature.

The EPU analyses of the CCW system took into consideration the lower tube resistance value of 0.00285 °F-hr-ft^2/Btu for all accident cases and included the water qualities associated with a higher percentage salinity including density, viscosity, specific heat and thermal conductivity. The analyses have concluded that, when kept to a tube resistance value of 0.00285 °F-hr-ft^2/Btu or less, two CCW heat exchangers are capable of removing the design basis accident heat load with the technical specification UHS temperature limit of 100°F. The surveillance and testing procedures will be adequate to maintain the level of cleanliness required by the EPU analyses which encompasses any changes in fouling potential.

Therefore, the existing methodology for complying with NRC Generic Letter 89-13, Service Water Problems Affecting Safety-Related Equipment, for the monitoring of safety related heat exchangers is adequate.

SBPB-1.4 **Section 2.5.4.4 of Attachment 4 to the license amendment request explains that the average intake temperature is 2.5° F above the average ambient air temperature. It also describes that the closed cooling water canal system is a 13.2 mile long water circuit that takes 44 hours to transit and services Turkey Point Units 1, 2, 3 & 4. This section also includes the following information:**

> **The Ultimate Heat Sink will continue to provide the required water supply and heat sink capacity at EPU conditions; the Intake Cooling Water flow requirements for cooling of safety-related heat exchangers either do not change or decrease slightly. The maximum increase in cooled water temperature leaving the cooling canal system to return to the units is approximately 0.9°F, from 91.9°F to 92.8°F.**

Since the return temperature is expected to increase, the staff does not consider the heat sink as one with effectively infinite capacity. Explain the methodology and assumptions used to determine the maximum increase in water temperature supplied to the units. Address how any changes in meteorological conditions since original licensing (especially increases in maximum observed wet and/or dry bulb temperatures) were considered in the analysis.

The effect of EPU on temperatures in the cooling canal was assessed as part of the

Site Certification Application (Reference 4) that was submitted to the Florida Department of Environmental protection for the uprate. The model was run to simulate existing operation of the cooling canal system using the data obtained from the National Climatic Center for Miami International Airport, over a 60 month period, January 1998 through December 2002. The canal was studied as a finite body of water to evaluate the environmental impact of increased heat loads at EPU.

Although the ultimate heat sink (UHS) is finite in volume, the water temperature post-EPU will not increase indefinitely. Instead the temperature of the cooling canal will increase slightly as it approaches a new thermodynamic equilibrium with the environment. The UHS was evaluated as a thermodynamic control volume, with heat inputs and losses re-balanced using historical data to yield a new steady state temperature. The new temperature is a strong function of the conditions which affect evaporation and makeup water to the canal and is also a function of the higher EPU thermal discharge from the two units. The final evaluation after accounting for the above factors determined that the maximum temperature increase would be 0.9°F in magnitude above the historical normal high temperatures.

The UHS normal operating temperature increase was determined by modeling the cooling canal system. The methodology used in the model to determine the steady-state temperature of the cooling canal at the Turkey Point site involved the summation of the following heating and cooling processes which influence temperature:

Heating Process
1. Absorption of short-wave radiation from the sun and the sky
2. Absorption of long-wave radiation from the atmosphere
3. Heat rejected to the water by the plant
4. Convection of heat through the bottom of the water body from the interior of the earth
5. Transformation of kinetic energy to heat
6. Heating due to chemical processes
7. Condensation of water vapor

Cooling Process
1. Reflection of short-wave solar radiation by the water
2. Reflection of long-wave atmospheric radiation by the water
3. Long-wave radiation emitted by the water
4. Conduction of sensible heat to the atmosphere
5. Heat carried away by evaporation

The Heating Process terms 4 through 7 are small in comparison with terms 1 through 3 and were neglected. The model derivation assumes that the only mechanisms of heat transfer into the heated water body that need to be considered are the absorption of short-wave radiation from the sun and sky, the absorption of long-wave radiation from the atmosphere, and the heat rejected to the water body by the plant.

Meteorological data was collected for the five year period from January, 1998 through December, 2002 from the National Climatic Data Center for Miami International Airport. These data include ambient air dry-bulb temperature, precipitation, dew point, wind speed, barometric pressure, and sky cover (which were utilized to estimate % sunshine).

The primary assumption of the model is that it is a steady state energy balance based on a 5 day time step approach. This assumption provides for the time step to be long enough for transient factors to be dampened out. For example, the diurnal variation in air temperature occurs too fast for a large body of water to follow: therefore the time step that is appropriate has been found to be 5 days.

The model includes the condenser inlet temperature and natural and forced equilibrium temperatures, heat exchange coefficients and the evaporation on a monthly basis.

Additionally, the model assumes the canal sides are essentially vertical, as verified by historical records showing the cooling canal water level closely follows the tidal water level in Biscayne Bay. For modeling purposes, the cooling canal system water surface area was assumed to be a constant 4370 acres, and the capacity was assumed to vary between 10,051 acre-feet at low tide and 14,421 acre-feet at high tide.

Finally, the model assumes the nuclear units were operating at 100% capacity and the fossil units were assumed to be operating at actual historical capacities.

The evaluation of the UHS temperature rise does not impact the existing licensing bases of the Turkey Point units. Technical Specification 3.7.4 requires that the average supply water temperature to the UHS be less than or equal to 100°F in modes 1 through 4. If the temperature is greater than 100°F, the Limiting Condition for Operation requires shutdown of both units. All of the accident analyses in which the UHS temperature is pertinent were evaluated at the limit of 100°F to yield bounding results. Although the temperature rise in the UHS at EPU is expected to decrease the margin between the operating temperature and the allowable Technical Specification limit, it does not change the allowable limit. In no case, as explained below, will the average supply water temperature to the UHS increase above 100°F.

SBPB-1.5 Section 2.12.1.2.3.2 of Attachment 4 to the license amendment request indicates that FPL will compare transient test data for tests listed in Table 2.12-2, "Large Plant Transient Tests in Turkey Point EPU Power Ascension Test Plan,"

against predictions provided by the same analytical models used in design verification for EPU. This section also includes the following statement:

> **Any significant differences between predictions and test data will be evaluated and reconciled before proceeding with the power ascension.**

The tests listed in Table 2.12-2 include a 10 percent ramp load change at 30 and 100 percent EPU power; and steam generator level/feedwater flow dynamic tests at 30, 87, and 95 percent EPU power.

Explain the scope of the analytical models (i.e., assumed boundary conditions, components explicitly modeled, and method of establishing response of individual control systems) and the criteria that would be employed to evaluate reconciliation of test results with model predictions prior to proceeding with power ascension.

The 10 percent ramp load change at 30 and 100 percent EPU power and the steam generator level/feedwater flow dynamic tests at 30, 87, and 95 percent EPU power were not explicitly analyzed for the PTN 3 and 4 Extended Power Uprate (EPU) program. However, the combination of the plant specific analytical results of bounding transients at EPU conditions along with the appropriate test acceptance criteria for the proposed power ascension tests will be used to reconcile the test results prior to proceeding with power ascension.

The PTN 3 and 4 plant models were developed to perform normal condition transient analyses at EPU conditions. The codes used for these analyses have been shown to predict plant specific transient results. The results of the PTN 3 and 4 normal condition analyses using these codes have demonstrated that plant transients that bound the ramp load change and the steam generator level/feedwater flow dynamic transients, which will be tested during EPU power ascension, meet applicable acceptance criteria. Although specific power ascension test transient acceptance criteria will be developed to evaluate these transient tests, the results of the bounding plant transient analyses provide general acceptance criteria and information on the expected plant trending response. The justification for this proposed method follows:

The normal operational transients (Condition I) analyzed at EPU conditions using the PTN 3 and 4 model of the LOFTRAN code include the 10 percent turbine load step increase from 90 percent power and 10 percent step load decrease from 100 percent power; and the 50 percent load reduction from full power. The results of the 10 percent step load change analyses bound the 10 percent ramp change transient. These results are provided in LR Section 2.4.2, Plant Operability (Margin to Trip). Since LOFTRAN does not capture the thermal hydraulic details of the steam generator water level shrink/swell behavior, normal operational transients at EPU conditions including the bounding 50 percent load reduction from full power were also analyzed using the PTN 3 and 4 models in the Advanced Computer Simulation Language (ACSL) code. It has a detailed steam generator model for analyzing the level response during normal condition transients. The results of the 50 percent load reduction from full power analysis bound the steam generator level/feedwater flow dynamic tests at 30, 87, and 95 percent EPU power. The LOFTRAN and ACSL code background will be described below.

The NRC Safety Evaluation Report (SER) for Westinghouse Topical Report WCAP-7907-P-A (Reference 5) describes the LOFTRAN verification process performed by Westinghouse for transients including a reactor trip from 100 percent power, a 100 percent load reduction, and step load changes up to 44 percent load. The verification process consisted of a comparison of LOFTRAN results to actual plant data as described in Section 6 of the LOFTRAN SER. The LOFTRAN code has been used for the plant operational transient analyses for Beaver Valley, Ginna, and Point Beach EPU programs and Seabrook, Vogtle, Farley, and Millstone Stretch Power Uprate (SPU) programs. The LOFTRAN code models a complete NSSS plant transient response with control system feedbacks. The LOFTRAN code has also been used for the safety analyses.

A Westinghouse configured computer code in ACSL was used to analyze a bounding 50 percent load reduction transient at EPU conditions to determine the steam generator level/feedwater dynamic responses to the transient. It has a detailed model of the steam generators and feedwater system including the feedwater pumps, feedwater regulating valves, and the feedwater control system to accurately predict the shrink/swell of the steam generator water level in transient conditions. Although this code has not been formally reviewed by the NRC, it has been demonstrated to compare well against plant data and has been used for other similar EPU programs, such as for Beaver Valley Units 1 and 2.

The LOFTRAN results for the10 percent step load increase and decrease analyses, which bound the 10% ramp change transient, demonstrate that applicable acceptance criteria are met at EPU conditions. These include no challenges to any reactor trip or engineered safety features actuation signal (ESFAS) setpoints and smooth plant parameter responses without excessive parameter divergences. The ACSL results of the 50 percent load reduction transient analysis at EPU conditions, which bounds the level setpoint step-changes of the steam generator level/feedwater flow dynamic tests, also meet applicable acceptance criteria. These include demonstrating that minimum steam generator level remains above the steam generator low level reactor trip setpoint; the maximum steam generator level remains below the steam generator high-high turbine trip setpoint and the steam generator level and feedwater flow responses are smooth without excessive divergences.

The LOFTRAN and ACSL Codes have been demonstrated to reliably predict acceptable plant responses to normal plant transients including those at other similar EPU programs. As described above, these include transients that bound the planned PTN 3 and 4 ten-percent ramp load change and the steam generator water level step change transients at EPU conditions. Although detailed acceptance criteria for these transient tests will be developed and included in power ascension test procedures, they will include the following general acceptance criteria based on the analyses of the bounding plant transients:

10 percent Ramp Load Test

- Reactor coolant system (RCS) average temperature, pressurizer pressure, and pressurizer water level will be controlled to the programmed values.
- Steam generator water level will demonstrate good feedwater level control and maintain acceptable margin to the trip level setpoint.
- Nuclear power peak overshoot/undershoot should be less than 3 percent reactor thermal power.
- Steam generator water level should return to programmed level setpoint within ±2 percent narrow range with dampening oscillations within 15 to 20 minutes.

Steam Generator Water Level Setpoint Step Test

- Steam generator water level will demonstrate good feedwater level control and maintain acceptable margin to the trip level setpoint.
- Steam generator water level should return to programmed level setpoint within ±2 percent Narrow range Span (NRS) with dampening oscillations within 15 to 20 minutes.

Although the peak parameters of the 10 percent ramp load test will not be as severe, the bounding LOFTRAN analysis results provide information on what the expected general trend of plant parameters (i.e. RCS average temperature, pressurizer pressure, and steam pressure) should be to changes in turbine load. The ACSL steam generator water level results of the 50 percent load reduction from full power can also be used to evaluate the 10 percent step ramp change test. For example, the ramp load change test steam generator water level response should trend in the similar direction as the ACSL 50 percent load reduction results.

SBPB-1.6 Section 2.12.1.2.6.2 of Attachment 4 to the license amendment request provides FPL's justification for exception to performance of certain tests, including the manual turbine trip from 100 percent power, which FPL described as a test to demonstrate that the control systems act together to maintain nuclear steam supply system parameters within design limits post-trip and to demonstrate that main steam safety valves (MSSVs) do not open. This section also includes the following statement:

An analysis of a manual reactor trip from 100% EPU power was performed using the LOFTRAN code as described in LR Section 2.4.2. The post-trip results of the manual reactor trip are very similar to a manual turbine trip

from 100% power conditions. The reactor trip from full power transient is initiated by a reactor trip followed by an automatic turbine trip on reactor trip in less than half a second. As such post-trip results are very similar.

The staff disagrees with the statement that the transient response of the plant to a reactor trip followed by an automatic turbine trip is similar to a transient initiated by a turbine trip. The additional half second of steam flow following the manual reactor trip significantly reduces the stored energy in the reactor coolant system and greatly reduces the likelihood that steam generator pressure would exceed the lowest setpoint of the MSSVs. Explain the measures taken to minimize challenges to the MSSVs for anticipated operational occurrences, such as turbine trips, and commit to additional testing demonstrating the adequacy of the measures or provide the assumptions, methodologies, and results for necessary supporting analyses demonstrating the adequacy of the measures.

A manual turbine trip followed by an automatic reactor trip will provide secondary side peak steam generator pressure slightly higher than a manual reactor trip followed by a turbine trip. As discussed below, margins to the Main Steam Safety Valves (MSSVs) actuation setpoint will, therefore, be slightly less for the turbine trip followed by an automatic reactor trip transient. The results of the LOFTRAN analyses of a normal reactor trip followed by a turbine trip can be used to demonstrate a manual turbine trip followed by an automatic reactor trip transient will not challenge the MSSVs. This analysis is described below. Based on this, additional power ascension testing demonstrating the adequacy of the plant performance is not required.

The LOFTRAN PTN 3 and 4 plant model was developed to represent the PTN 3 and 4 plant configuration at the EPU conditions. As noted above for response to SBPB question 1.5, LOFTRAN is an NRC-approved code for transient analyses including condition I (normal operational transients). The LOFTRAN code is also suitable for use for upset conditions, such as reactor trip and turbine trip transient analyses. Therefore, the results of the LOFTRAN analysis, with the PTN 3 and 4 plant specific EPU configurations, are representative of the actual PTN 3 and 4 plant responses.

A normal reactor trip transient from full power followed by an automatic turbine trip was analyzed for PTN 3 and 4 EPU Program using the LOFTRAN code. The purpose of this analysis was to demonstrate that steam generator Main Steam Safety Valves (MSSVs) are not challenged, the low pressurizer pressure SI setpoint is not actuated and the pressurizer heaters remain submerged during and following the transient. This specific transient is modeled as opposed to the turbine trip transient to maximize the post trip plant cooldown. The reactor trip transient is initiated by a manual reactor trip and is followed by an automatic turbine trip after a 2 second delay. Auxiliary feedwater flow is assumed to initiate on low-low steam generator water level. The results of the transient analysis demonstrated that none of the acceptance criteria were challenged and that the plant was controlled to a stable near no-load condition.

The PTN 3 and 4 specific LOFTRAN results for a normal reactor trip transient can be used to extrapolate the peak steam generator pressures for the manual turbine trip transient followed by an automatic reactor trip transient.

As noted by the staff in this question, a turbine trip followed by a reactor trip will provide a slightly higher steam generator secondary side pressure than a reactor trip followed by a turbine trip transient. The manual turbine trip followed, after a small delay (less than 1 second), by an automatic reactor trip would result in decreased heat removal from the primary side. The RCS average temperature and steam generator pressure would increase initially until the steam bypass valves actuate. Actuation of the steam bypass valves will turn around the secondary pressure increase and the secondary pressure as well as primary temperature would start to decrease. As the RCS average temperature decreases, the steam bypass valves will start to close and would completely close when the RCS vessel average temperature reaches the no-load value. Without any operator action, at the end of the transient the steam bypass valves would again open to maintain RCS average temperature and steam pressure at the steady state no load condition. Note that the initial steam generator pressure increase is limited by the steam bypass valves actuation but the peak steam generator pressure generally occurs at the end of the transient when the steam bypass valves are maintaining RCS average temperature at the no-load value. The manual turbine trip followed by a reactor trip will have an increase in the initial peak pressure compared to the manual reactor trip followed by an automatic turbine trip. However, the initial peak pressure of the manual turbine trip followed by an automatic reactor trip will remain less than the maximum pressure obtained at the end of the transient which is the same for both transients.

The LOFTRAN results of the manual reactor trip followed by an automatic turbine trip, calculated a steam generator secondary side peak pressure of 998 psia which occurred at the end of the transient. With the first safety valve actuation setpoint of 1100 psia, the calculated available margin to the MSSV was 102 psi. The peak pressure which occurred during the initial phase of the transient (when the steam bypass valves modulated open and then closed) was approximately 940 psia. The initial peak steam generator pressure during the initial phase of a turbine trip followed by a reactor trip transient would increase higher than a reactor trip followed by an automatic turbine trip, but would continue to remain below the peak pressure at the end of the transient. The peak pressure at the end of the transient would be the same for both transients thereby demonstrating that there are adequate margins to the MSSVs lift setpoints during a turbine trip followed by an automatic reactor trip transient for PTN 3 and 4 at the EPU conditions.

Based on LOFTRAN code transient results specific to the PTN 3 and 4 at the EPU conditions and the available margins during the normal reactor trip transient results, the manual turbine trip transient followed by an automatic reactor trip demonstrates successful results that will not challenge the MSSVs or other ESFAS actuation.

Therefore, additional power ascension tests to demonstrate the adequacy of the plant during such transients are not required.

References

1. M. Kiley (FPL) to U.S. Nuclear Regulatory Commission (L-2010-113), "License Amendment Request No. 205: Extended Power Uprate (EPU)," (TAC Nos. ME4907 and ME4908), Accession No. ML103560169, October 21, 2010.
2. Email from J. Paige (NRC) to T. Abbatiello (FPL), "Turkey Point EPU – Balance of Plant (SBPB) Request for Additional Information – Round 1," Accession No. ML110770196, March 18, 2011.
3. M. Kiley (FPL) to U.S. Nuclear Regulatory Commission (L-2011-102), "Response to NRC Request for Additional Information (RAI) Regarding Extended Power Uprate (EPU) License Amendment Request No. 205 and Unit 3 Mechanical/Civil Issues" Accession No. ML110880060, dated March 25, 2011.
4. Florida Power & Light Company (FPL), 2008, Site Certification Application (SCA), Turkey Point Uprate Project, January 2008.
5. WCAP-7907-P-A, LOFTRAN Code Description, April 1984.