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W3F1-2004-0105

November 8, 2004

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

SUBJECT: Supplement to Amendment Request NPF-38-269
Extended Power Uprate
Waterford Steam Electric Station, Unit 3
Docket No. 50-382
License No. NPF-38

REFERENCES:
1. Entergy Letter dated November 13, 2003, "License Amendment Request NPF-38-249 Extended Power Uprate"
2. NRC Letter dated October 26, 2004, Waterford Steam Electric Station, Unit 3 (Waterford 3) – Request for Additional Information Related to Revision to Facility Operating License and Technical Specification – Extended Power Uprate Request (TAC No. MC1355)
3. Entergy Letter dated July 14, 2004, "Supplement to Amendment Request NPF-38-249, Extended Power Uprate"

Dear Sir or Madam:

By letter (Reference 1), Entergy Operations, Inc. (Entergy) proposed a change to the Waterford Steam Electric Station, Unit 3 (Waterford 3) Operating License and Technical Specifications to increase the unit's rated thermal power level from 3441 megawatts thermal (MWt) to 3716 MWt.

On October 15, 2004, Entergy and members of your staff held a call to discuss the need for transient testing following the implementation of the Extended Power Uprate (EPU). As a result of this call, a Request for Additional Information (RAI) (Reference 2) was issued to Entergy on October 26, 2004. Entergy's response to the RAI is contained in Attachment 1.

There are no technical changes proposed. The no significant hazards consideration included in Reference 3 is not affected by any information contained in the supplemental letter. There are no new commitments contained in this letter.

If you have any questions or require additional information, please contact D. Bryan Miller at 504-739-6692.

A001

I declare under penalty of perjury that the foregoing is true and correct. Executed on November 8, 2004.

Sincerely,

TGM/DBM/cbh

Attachment:
1. Response to Request for Additional Information

cc: Dr. Bruce S. Mallett
U. S. Nuclear Regulatory Commission
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Arlington, TX 76011

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Killona, LA 70066-0751

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Washington, DC 20555-0001

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Louisiana Department of Environmental Quality
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American Nuclear Insurers
Attn: Library
Town Center Suite 300S
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Attachment 1

To

W3F1-2004-0105

Response to Request for Additional Information

Response to Request for Additional Information Related to Transient Testing

Question:

In general, the NRC staff does not review and approve the application of computer codes and analyses that are credited for evaluating balances-of-plant performance and primary / secondary interactions. Consequently, the startup test program is relied upon as a quality check to: a) confirm that analyses and any modifications and adjustments that are necessary for a proposed extended power uprate (EPU) have been completed properly, and b) benchmark the analyses against the actual integrated performance of the plant, thereby assuring conservative results. This is consistent with the requirements stated in Title 10 of the Code of Federal Regulations (10 CFR) Part 50, Appendix B, which states that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate calculational methods, or by the performance of a suitable testing program; and requires that design changes be subject to design control measures commensurate with those applied to the original plant design (which includes startup testing).

In order to implement the proposed EPU at Waterford 3, the main steam system will operate at a lower pressure and higher mass flow rate, with corresponding operating conditions for the main feedwater system. In order to accommodate these revised operating conditions, the following changes are necessary:

a. The reactor power cutback system will be put in service at 65 percent power (instead of the current 70 percent), and the reactor trip on turbine trip setpoint will be reduced to 65 percent, to compensate for the relative reduction in the capacity of the steam bypass control system (SBCS).

b. Changes to the controllers and/or setpoints of the atmospheric dump valves (ADVs) are being made in order to maintain adequate margin between the actuation setpoints for the SBCS and the ADVs, providing assurance that the ADVs will not actuate prematurely (the SBCS is relied upon to prevent unnecessary challenges to the ADVs).

c. A new high pressure main turbine rotor with all reaction blading is being installed, potentially affecting the inertia of the main turbine and overshoot during a turbine overspeed transient, such as during a loss-of-load.

d. Modifications to various control systems and setpoints will be required to ensure that the plant will be maintained within desired operating bands during normal operations arid during minor load changes and load rejection events.

Entergy's test program primarily includes steady-state testing with some minor load changes, and no large-scale transient testing is proposed. Sufficient information has not been provided to demonstrate that, in the absence of large-scale transient testing, the integrated plant response during transient conditions will be as expected. Entergy is, therefore, requested to either: a. provide additional information that explains in detail how the proposed EPU startup test program, in conjunction with the original Waterford 3 startup test results and applicable industry experience, assure the plant will respond as expected during postulated transient

conditions following implementation of the proposed EPU, given the revised operating conditions that will exist and plant changes that are being made; or b. describe transient testing that will be included in the startup test program in order to provide this assurance, and explain in detail how the proposed transient testing will accomplish this.

Response:

10CFR 50, Appendix B, states that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate calculational methods, <u>or</u> by the performance of a suitable testing program. For postulated transient conditions Entergy Operations, Inc. (Entergy) verifies the design adequacy of the proposed EPU changes at Waterford Steam Electric Station, Unit 3 (Waterford 3) in part through a combination of calculational methods and the performance of a suitable testing program.

Entergy utilizes calculational models, specifically the Long Term Cooling (LTC) Code, to evaluate postulated transient conditions affecting Nuclear Steam Supply System (NSSS) control systems, balance-of-plant performance, and primary/secondary interactions. The strength of utilizing computational models, verses plant testing, is in the numerous transient scenarios and operating conditions that can be evaluated using a valid computational model, verses the limited scenarios and operating conditions that will be evaluated in any test program. Whereas a plant test can verify acceptable results for a single transient scenario at a single operating condition, a computational model can test any number of combinations of conditions and scenarios, including conditions more limiting than can be achieved in the actual plant (e.g., for a worst case Moderator Temperature Coefficient (MTC) value that exceeds the conditions at the time of a test, or at any time during a particular cycle). Additionally, a valid calculational model can be used to evaluate plant modifications, and to predict changes in plant transient response resulting from those plant modifications.

For a calculational model to be effective it must accurately model the actual plant. This is demonstrated by performing baseline studies of the model by comparing the calculational result to data from the same plant transient at identical operating conditions. Good correlation between data from the actual plant transient and the results predicted by the calculational model assures the plant is appropriately modeled, and provides an improved level of assurance that the calculational model will accurately predict the plant response to postulated transients and operational conditions.

Entergy will demonstrate:

1. That the proposed plant modifications for EPU either:
   a) Have no significant impact on transient response; or
   b) Are accurately modeled by the LTC Code, which is suitable for predicting the effect on plant transient response due to those modifications;

2. That the startup test program post modification testing adequately demonstrates that any modifications and adjustments required by EPU have been completed properly;

3. That the LTC Code is an acceptable calculational method for evaluating postulated transient conditions affecting NSSS control systems, primary/secondary interactions, and balance-of-plant (BOP) performance as it relates to integrated plant response in transient conditions.

4. That the LTC Code has been properly benchmarked against the actual integrated performance of the plant, with acceptable agreement between the LTC Code prediction and the actual plant response;

5. That the LTC Code is suitable for predicting transient response at operating conditions which differ from the benchmark conditions;

6. That the proposed plant maneuvering tests (Transient Data Record, Load Change test) specified in Entergy letter W3F1-2004-0004, "Supplemental Information Extended Power Uprate - Power Ascension Testing," dated January 29, 2004 represent an integrated test of control systems through a wide range of operating conditions.

Additionally, Entergy will address the following:

1. The four specific plant changes discussed in the Request for Additional Information (RAI);

2. Comparison of the transient testing performed in the original plant startup test program with the testing proposed for EPU;

3. Industry experience with using calculational models for predicting transient response post power uprate.

4. Negative aspects inherent in any large transient test.

1. Plant Modifications

Table 1 provides a list of plant modifications planned for EPU, whether they have a potential impact on plant transient response, whether that potential response is modeled in the LTC Code, the proposed post modification test, and any subsequent confirmatory transient tests planned as part of the EPU testing. A discussion of the individual modifications follows the table. Note that incidental modifications associated with EPU, such as changes to alarms, indications, and instrument scaling are not listed here as these changes do not impact transient response.

The following modifications constitute planned actions on the part of Waterford 3. Further evaluations may identify the need for additional modifications and tests or eliminate the need for some modifications and tests. As such, this list is not a formal commitment to implement the modifications and testing exactly as planned. Additionally, construction, installation, and/or pre-operational testing for each modification will be performed in accordance with the plant design process procedures and these tests are not listed herein. The tests listed are the final acceptance tests that will demonstrate the modifications will perform their design function and integrate appropriately with the existing plant.

TABLE 1
SUMMARY OF EPU Modifications

	Description	Potential Impact on Transient Response	Modeled in Transient Analysis	Post Mod Test	EPU Startup Testing (W3F1-2004-0004 dated January 29, 2004)
High Pressure (HP) Turbine Replacement	Replace Rotor with all reaction blade HP rotor	No	No	120% rotor speed factory test Overspeed Trip Test Vibration Monitoring Thermal Performance Test	NSSS/BOP Plant Data Record Transient Data Record Vibration monitoring Validate TFSP Correlation Constants
Main Generator Stator Rewind	Restore to original nameplate capability	No	No	Pre-Operation Electrical Tests Generator Capability Test Vibration Monitoring Isophase Bus Temp Monitoring	NSSS/BOP Plant Data Record Transient Data Record Vibration monitoring
Condenser Tube Staking	Install additional tube support.	No	No	Circulating Water tube leak check Monitor Secondary Chemistry	Monitor Secondary Chemistry
Drain Collection Tank (DCT) Normal Level Control Valve (NLCV) trim change	Replace internal valve trim for additional flow capacity	No	No	Channel Calibration Air Operated Valve (AOV) Testing	NSSS/BOP Plant Data Record Transient Data Record Load Change Test
Main Transformer (MT) A Replacement	Replace degraded MT A with new transformer to accommodate higher current	No	No	100% factory load test Monitor Oil Temperatures Test Oil Samples Temperature survey of connectors	Monitor Temperatures
MT B Cooling Upgrade	Add 1 additional bank of cooling to accommodate higher current.	No	No	Monitor Oil Temperatures Test Oil Samples Temperature survey of connectors	Monitor Temperatures
Oil Circuit Breaker (OCB) Replacement	Replace to accommodate higher current.	No	No	Timing tests, resistance tests, power factor tests, AC and DC acceptance tests, and calibrate the synchronizing check circuit.	

TABLE 1
SUMMARY OF EPU Modifications

	Description	Potential Impact on Transient Response	Modeled in Transient Analysis	Post Mod Test	EPU Startup Testing (W3F1-2004-0004 dated January 29, 2004)
Stator Cooling Water (SCW) Alkalizer Skid	Install a SCW Alkalizer Skid to control SCW chemistry.	No	No	Setup and adjustments by vendor SCW conductivity monitor calibration Chemistry monitoring	
Atmospheric Dump Valve (ADV) Setpoint Change	Change setpoint from 1050 psig to 992 psig	Yes	Yes	Channel Calibration	NSSS/BOP Plant Data Record Transient Data Record
Digital-electro Hydraulic (DEH) Program Constants	Eliminate sequential valve operations Define new flow curves Change operating ranges	Yes	Yes*	Channel Calibration	NSSS/BOP Plant Data Record Transient Data Record Load Change Test
Feedwater Control System (FWCS) Program Constants	Changed the flow at which Feedwater (FW) Pump speed begins to increase: from 37.5% to 33.3%	Yes	Yes	Channel Calibration	NSSS/BOP Plant Data Record Transient Data Record Load Change Test
Steam Bypass Control System (SBCS) Program Constants	See Table 2	Yes	Yes	Channel Calibration	NSSS/BOP Plant Data Record Transient Data Record

* Turbine Setback and Runback signals originate in the SBCS, which is modeled in the LTC Code.

TABLE 1
SUMMARY OF EPU Modifications

	Description	Potential Impact on Transient Response	Modeled in Transient Analysis	Post Mod Test	EPU Startup Testing (W3F1-2004-0004 dated January 29, 2004)
Reactor Regulating System (RRS) Program Constants	Change Tref range from 544.6 - 574.0 F to 541.0 - 571.9 F	Yes	Yes	Channel Calibration	NSSS/BOP Plant Data Record Transient Data Record Load Change Test
Pressurizer Level Control System (PLCS) Program Constants	Pressurizer Level band is unchanged. Change Tave range from 544.6 - 574.0 F to 541.0 - 571.9 F	Yes	Yes	Channel Calibration	NSSS/BOP Plant Data Record Transient Data Record Load Change Test
Low Steam Generator (S/G) Press Setpoint	Change from 764 psia to 666 psia	Yes	Yes	Channel Calibration	NSSS/BOP Plant Data Record
Reactor Power Cutback System (RPCS) Reactor Trip on Turbine Trip (RT/TT)	RPCS and RT/TT are not being modified. ENI setpoint which activates RT/TT will be lowered	Yes	Yes	None for RPCS and RT/TT Channel Calibration for ENI	

a. Modifications with no Significant Effect on Transient Response

HP Turbine Replacement - The high pressure turbine rotor will be replaced with all-reaction blade rotor. To support the new all-reaction blade rotor, the inner cylinder, inlet flow guide, and steam sealing components will be replaced. The turbine casing, steam supply, governor and throttle vales will remain unchanged.

The Main Turbine responds directly to governor valve position as controlled by the Digital-electro Hydraulic (DEH) control system. The important function of the main turbine in transient and accident analysis is to respond to signals developed by DEH, and to respond to a turbine trip. This function is performed by the governor and throttle valves, DEH, and the Electro Hydraulic (EH) system. Except for DEH, which is discussed below, these components are not being modified for EPU. The stroke time of the Governor Valves and Throttle Valves, and the response time to turbine trip do not change.

The turbine rotor replacement does change the rotational inertia of the rotor, which can potentially affect the turbine overspeed transient. This effect is discussed in a separate section below (Additional Discussion, paragraph c.) Thus, with the two exceptions noted, this change has no impact on the integrated plant response during transient conditions.

Main Generator Stator Rewind – The Main Generator Stator will be replaced in place. This activity will restore the Main Generator to original nameplate capability. Thus, this change has no impact on the integrated plant response during transient conditions.

Condenser Tube Staking - Additional support staking of the main condenser tubes will be installed to minimize potential effects of flow induced vibration. This modification has an insignificant impact on the thermal performance of the condenser. Therefore, this change to the condenser has no impact on the integrated plant response during transient conditions.

DCT NLCV Trim - The Drain Collection Tanks (DCT) normal level control valves (NLCV) trim size will be increased to provide adequate level control capacity under the new operating conditions and to prevent opening of the DCT Alternate Level Control Valves (ALCV). Cycling the DCT ALCVs excessively would cause an unnecessary decrease in plant efficiency.

The new trim size will result in the DCT NLCVs being within the industry accepted control band of 20 to 70% open, and provides sufficient margin to accommodate a wide range of transient conditions. Thus, this change to the DCT NLCV will have no impact on the integrated plant response during transient conditions.

SCW Alkalizer Skid - A new Stator Cooling Water (SCW) alkalizer skid will be retrofitted into the existing generator stator cooling water system to control the pH of the system. The addition of the stator water alkalizer skid will enhance the reliability of the main generator by minimizing corrosion to the stator cooling water coils. The SCW alkalizer skid is a small subsystem of the SCW installed for chemistry control only, and has no impact on the integrated plant response during transient conditions.

MT A Replacement – The replacement of main transformer A is required since the current transformer cannot meet its maximum nameplate capability even with additional cooling. This modification does not change the design function of the equipment, nor will any new system

interactions be created. Therefore, the new transformer will have no impact on the integrated plant response during transient conditions.

MT B Cooling Upgrade - The additional cooling for main transformer B is required to upgrade the transformer to its maximum nameplate rating. This modification does not change the design function of the equipment, nor will any new system interactions be created. Therefore, the added cooling to main transformer B has no impact on the integrated plant response during transient conditions.

OCB Replacements - Both existing Oil Cooled Breakers (OCB) will be replaced with new with higher capacity gas generator output breakers (GOB) (generator output breaker 'B' was replaced and tested during RF12 in the fall of 2003). The GOB has a singular function to open upon demand, either from a normal or protective actuation signal. This modification does not change the design function of the equipment, nor will any new system interactions be created. Therefore, the replacement breakers have no impact on the integrated plant response during transient conditions.

b. Modifications with Potential Effect on Transient Response

ADV Setpoint Change – The ADV setpoint will be changed from 1050 psig to 992 psig to support EPU. The setpoint is manually set, and controlled by the operator. No aspect of the ADV controller or valve operator is being modified for EPU. To aid the operator in setting the ADV controller setpoint, the setpoint signal from the controller will be sent to the Plant Monitoring Computer (PMC). This will require the installation of an additional interfacing circuit card. A loop calibration will be performed to verify that this modification has been completed properly.

The setpoint of the ADV can affect the plant transient response, and it is modeled in the LTC Code for control systems evaluation as well as in the Small Break Loss of Coolant Accident (SBLOCA) Emergency Core Cooling System (ECCS) analyses where it is credited.

DEH Program Constants – Program constants changes are required in DEH to: 1) Deactivate the sequential valve operation option; 2) define the flow curves of the new HP Turbine; and 3) change the operating range for MW, impulse pressure, and reheat pressure. The changes in operating ranges also require corresponding changes in the associated maximum limits, and feedback loop gains.

At Waterford 3, DEH is operated as a manual controller during normal operations, with MW and impulse feedback loops removed from service. The governor valve position does not change with changes in turbine or generator load. The operator inputs the desired governor valve position, and the rate of valve movement. Once the demanded governor valve position is achieved, further valve movement is initiated only by operator demand, or a Setback/Runback signal. The Setback/Runback signal originates in the SBCS. Only the Setback/Runback function of DEH is modeled in the LTC Code.

FWCS Program Constants – The flow demand at which the FW Pump speed begins to increase will be lowered from 37.5% flow demand to 33.3% flow demand, to improve valve flow control when operating with only one FW Pump. The maximum FW Pump speed demand is unchanged. This will be affected by changing 2 program constants. There is no

physical change in the FWCS, or in any components controlled by the FWCS. The FWCS algorithm will not change.

SBCS Program Constants – Seven SBCS program constants will be revised for EPU, and are described below. These changes are needed to define the new operating point for EPU due to higher steam flow, lower steam pressure, and lower Reactor Coolant System (RCS) average temperature. Table 2 provides a summary of the SBCS setpoints that will be changed for the EPU.

The steam header pressure transmitter range will be increased to accommodate the lower main steam pressure that will exist at the higher power level. Also, since the instrument span for the steam header pressure is changing, the SBCS proportional constant (K) will also be increased.

The referenced100% power steam flow rate (W_{S100}) will be increased for EPU. The EPU average coolant temperature for hot zero power (T_{NL}) is being reduced, as well as the corresponding SBCS setpoint for hot zero power (HZP) steam pressure (S_B). Also, since the program reactor coolant system average temperature is being reduced, the low reactor coolant system average coolant temperature setpoint (V_T) for blocking the quick open signal is being reduced.

The slope constant (K_W) of the setpoint program is being revised to accommodate the main steam pressures that will exist at HZP and hot full power (HFP) post EPU.

The gain on the Tavg signal (KT_{AVG}) used in the turbine runback setpoint will also be increased. This change is required due to the lower Tave program band for EPU, and insures that the turbine runback signal is removed once plant conditions are restored to the programmed operating point (Tave, steam pressure).

Due to limitations in the range of adjustment of the related coefficient, increasing the referenced 100% power steam flow rate (W_{S100}) will require the installation of a 200kΩ resistor. There are no other physical changes to any components controlled by the SBCS. The SBCS algorithm will not change.

TABLE 2
SUMMARY OF STEAM BYPASS CONTROL SYSTEM SETPOINT CHANGES FOR EPU

Engineering Parameter	Current Setpoints	Extended Power Uprate Setpoints
STEAM BYPASS CONTROL SYSTEM – Steam Pressure Instrumentation		
Transmitter Range	800 – 1050 psia	750 – 1050 psia
STEAM BYPASS CONTROL SYSTEM		
K	1.66	2.00
W_{S100}	7.503×10^6 lbm/hr	8.285×10^6 lbm/hr
S_B	1000 psia	970 psia
V_T	562.0 °F	561.0 °F
K_W	-1.20 psi/%	-1.5 psi/%
KT_{AVG}	0.88 °F	1.05 °F

RRS Program Constants – The average RCS temperature control band will be changed from 544.6-574.0 F to 541.0-571.9 F. This will be affected by changing the 4 program constants which define the Tref curve. There is no physical change in the RRS, or in any components controlled by the RRS. The RRS algorithm will not change.

PLCS Program Constants – Pressurizer level control range will remain 33.1 - 55.6%. However, since average primary temperature range will change from 544.6-574.0 F to 541.0-571.9 F, a change to the PLCS program constants is required. There is no physical change in the PLCS, or in any components controlled by the PLCS. The PLCS program algorithm will not change.

Low S/G Press Setpoint – The Low Steam Generator Pressure trip setpoint will be changed from 764 psia to 666 psia to provide margin against spurious trips due to the lower post EPU HFP S/G pressure of approximately 810 psia. The design function of this plant protection system setpoint, as discussed in Technical Specification Bases 2.2.1, will remain the same and the system response following this trip or another event initiator will not change as a result of this setpoint change. The proposed low steam generator trip setpoint was incorporated into all applicable EPU safety analyses with acceptable results.

RPC and RT/TT – The Reactor Power Cutback (RPC) system and the Reactor Trip on Turbine Trip system (RT/TT) are not being modified for EPU. However, a setpoint contained within the Excore Nuclear Instruments (ENI) system below which RT/TT is automatically removed from service will be lowered due to EPU. Correspondingly, the procedural limit below which the operator may remove RPC from service will also be lowered. A full discussion of these changes is contained in a separate section below (see Additional Discussion, paragraph 1.a.)

2. Post Modification Testing

HP Turbine Replacement The HP Turbine rotor will be factory tested to 120% of synchronous speed. Pre-operational tests will include normal post maintenance type tests of the turbine, turbine auxiliaries, and protective trip features; and an overspeed trip test. Once in service, stable (NSSS/BOP) and Transient Data Records (including turbine vibration) will be collected. Changes in Turbine First Stage Pressure Power in the core operating limits supervisory system (COLSS) will also be validated. This testing adequately verifies that the HP turbine replacement has been completed properly.

Main Generator Stator Rewind – In addition to construction, installation, and pre-operational testing, stable (NSSS/BOP) and Transient Data Records (including main generator vibration and temperatures) will be collected during power ascension. Final acceptance will be an electrical capability test to demonstrate that the main generator can operate within its original capability curve. This testing adequately verifies that the main generator stator rewind has been completed properly.

Condenser Tube Staking Post installation inspection of the installed tube supports, inspections for evidence of tube leakage, and monitoring chemistry parameters upon secondary start up will verify that the modification was completed properly.

DCT NLCV Trim - Normal post modification testing will include AOV testing and control loop testing. Final acceptance criteria will be verification that the NLCV operates within the industry accepted control band of 20 to 70% open. This testing adequately verifies that the DCT NLCV trim replacement has been completed properly.

SCW Alkalizer Skid - Normal post modification testing will include a leak check of the system, setup and adjustments by the vendor, channel calibration of the SCW conductivity monitor. Final acceptance will be the monitoring of SCW chemistry parameters to verify that the SCW Alkalizer skid will maintain SCW chemistry within desired limits. This testing adequately verifies that the SCW Alkalizer Skid installation has been completed properly.

MT A Replacement – In addition to construction, installation, and pre-operational testing, a full load capacity test will be performed by the vendor and observed by Entergy prior to delivery of the new transformer. Post operational testing will include transformer temperature monitoring, periodic survey of 230 KV connection temperatures, and chemistry analysis, which will continue for 6 months post installation. This testing adequately verifies that the MT A replacement has been completed properly.

MT B Cooling Upgrade - In addition to construction, installation, and pre-operational testing, post operational testing will include transformer temperature monitoring, periodic survey of 230 KV connection temperatures, and chemistry analysis, which will continue for 6 months post installation. This testing adequately verifies that the MT B cooling upgrades have been completed properly.

OCB Replacements – Normal post modification testing will include timing tests, resistance tests, power factor tests, AC and DC acceptance tests, and a calibration of the synchronizing check circuit. This testing adequately verifies that the replacement of the generator output breakers has been completed properly.

ADV Setpoint Change – A verification of the proper setpoint will be performed per proposed TS Surveillance 4.7.1.7.b. A channel calibration will be performed to verify that the installation of an additional setpoint indication has been completed properly.

The NSSS/BOP Plant Data Record and the Transient Data Record will demonstrate that SBCS will actuate and control steam generator pressure without the actuation of the ADVs.

DEH Program Constants – A channel calibration will be performed to verify that the program constants changes have been completed properly, and will demonstrate proper controller demand (output) for a wide range of process inputs.

Additionally, the proper response of DEH will be validated by comparing the actual plant response with predicted response during the following startup tests: NSSS/BOP Plant Data Record, Transient Data Record, and Load Change Test. The Plant Data Record and the Transient Data Record demonstrate that DEH provides the proper valve position demand over a wide range turbine loads, during slow transients and at a variety of steady state conditions. The Load Change Test demonstrates the ability of the DEH to respond to a more rapid change in demand.

FWCS Program Constants - A channel calibration will be performed to verify that the program constants changes have been completed properly, and will demonstrate proper controller demand (output) for a wide range of process inputs.

The transient response of the FWCS and the integrated plant response during transient conditions has been evaluated using the LTC Code with acceptable results. As discussed in sections 3 and 4 below, calculation methods in general are effective tools for modeling changes to control systems and various operating condition. The LTC Code in particular is suited for evaluating changes to control systems (RRS, PLCS, SBCS, FWCS) since the algorithms in the LTC model mimic the algorithms in those controllers.

Additionally, the proper response of the FWCS will be validated by comparing the actual plant response with predicted response during the following startup tests: NSSS/BOP Plant Data Record, Transient Data Record, and Load Change Test. The Plant Data Record and the Transient Data Record demonstrate that the FWCS provides the proper flow over a wide range of flow demand, during slow transients and at a variety of steady state conditions. The Load Change Test demonstrates the ability of the FWCS to respond to a more rapid change in demand.

SBCS Program Constants - A channel calibration will be performed to verify that the program constants changes have been completed properly, and will demonstrate proper controller demand (output) for a wide range of process inputs.

The transient response of the SBCS and the integrated plant response during transient conditions have been evaluated using the LTC Code with acceptable results. Additionally, the proper response of the SBCS will be validated by comparing the actual plant response with predicted response during the following startup tests: NSSS/BOP Plant Data Record and Transient Data Record. The Plant Data Record and the Transient Data Record demonstrate that the SBCS will maintain program steam generator pressure over an attenuated range (zero to approximately 40%) of demand, during slow transients and steady state conditions.

RRS Program Constants - A channel calibration will be performed to verify that the minor changes to program constants have been completed properly, and will demonstrate proper controller demand (output) for a wide range of process inputs.

The transient response of the RRS and the integrated plant response during transient conditions have been evaluated using the LTC Code with acceptable results. Note that the RRS operates the Control Element Assemblies (CEA) through the Control Element Drive Mechanism System (CEDMCS), which is normally maintained in Off or in Manual mode, except for during a short time period immediately following a Reactor Power Cutback (RPC). For the RPC events, the LTC Code analysis conservatively assumed that the CEDMCS remains inactive.

Additionally, the proper response of the RRS will be validated by comparing the actual plant response with predicted response during the following startup tests: NSSS/BOP Plant Data Record, Transient Data Record, and Load Change Test

PLCS Program Constants A channel calibration will be performed to verify that the minor changes to program constants have been completed properly, and will demonstrate proper controller demand (output) for a wide range of process inputs.

The transient response of the PLCS and the integrated plant response during transient conditions have been evaluated using the LTC Code with acceptable results. As discussed in Sections 3 and 4 below, calculation methods in general are effective tools for modeling changes to control systems and various operating condition. The LTC Code in particular is suited for evaluating changes to control systems (RRS, PLCS, SBCS, FWCS) since the algorithms in the LTC model mimic the algorithms in those controllers.

Additionally, the proper response of the PLCS will be validated by comparing the actual plant response with predicted response during the following startup tests: NSSS/BOP Plant Data Record, Transient Data Record, and Load Change Test

Low S/G Press Setpoint A channel calibration will be performed to verify that the Low S/G Pressure trip setpoint change has been completed properly. The Low S/G Pressure trip setpoint is a static value, and as such has no transient response. The design function of this plant protection system setpoint, as discussed in Technical Specification Bases 2.2.1, will remain the same and the system response following this trip or another event initiator will not change as a result of this setpoint change. The proposed low steam generator trip setpoint was incorporated into all applicable EPU safety analyses with acceptable results.

NSSS/BOP Plant Data Record will demonstrate that the plant can be operated at 100% power while maintaining an acceptable margin between steam generator pressure and the Low S/G Pressure Pretrip setpoint.

RPC and RT/TT – No modifications are planned for RPC and RT/TT. A channel calibration will be performed to verify that the revised ENI setpoint change has been completed properly.

3. LTC Code

The Westinghouse Electric Company LTC code is a best-estimate nuclear power plant simulation tool which analyzes the thermal-hydraulic response of the Combustion Engineering (CE) NSSS to a wide variety of plant transients. These include load maneuvering transients (steps and ramps), equipment malfunctions (such as a loss of a feedwater pump) and plant trips. The code can be used for overall power plant design, NSSS control system design, engineering analysis of plant transients, and the development of classroom training material. Major systems modeled in detail include a multi-loop reactor coolant system, main steam system, main and emergency feedwater systems, containment heat transfer, and all NSSS control systems. Other systems which influence the response of the major heat transport systems are also modeled. These include the chemical and volume control system, safety injection systems and a limited turbine system model. Plant monitoring, control and protection systems, including instrument lag times and instrument decalibration due to environmental effects, are also modeled. The LTC plant simulation model emphasizes first-principle simulations to realistically predict, in an integrated manner, the response of mechanical components, control systems, and fluid systems during plant transients. The plant system and component characteristics are defined through input data.

The code was developed in the late 1970's and has undergone continued development and improvement over the years. The fidelity of the LTC code is a result of a continuing engineering effort to accurately predict plant steady state and transient performance. The code has been successfully compared to detailed operating plant data from a wide range of foreign and domestic plants. The documented comparisons have included a reactor trip, turbine trip, loss of a feedwater pump, power steps and power ramps.

LTC Code Applicability to Control System Changes

The code is suited for evaluating the performance of the NSSS Control Systems including the RRS, PLCS, PPCS, SBCS, and the FWCS. The LTC code was used in the original development of these control systems and has been successfully used to evaluate design changes and setpoint changes to these control systems at Waterford 3 (e.g. for Thot Reduction), and at other CE design plants. The control system algorithms used by the LTC code are based upon the actual control system hardware design. The level of modeling detail of the NSSS control systems includes instrumentation and transmitter response times, control system logic down to the card level, dynamic compensation (lags, lead/lags, filtered derivatives and proportional + integral + derivative controllers), valve, valve actuator and pump characteristics.

The LTC code has been used at Waterford 3 to evaluate changes to the NSSS Control systems to operate at a new set of operating conditions for Thot reduction. The NSSS Control System setpoints provided by the LTC evaluation were installed in the unit and provided the expected control response without further control system changes. Additionally, the LTC Code was used successfully at Waterford 3 to evaluate control systems pursuant to the Appendix K power uprate.

4. LTC Code Benchmarking

Unlike during initial startup, when plant data was not available for compiling analytical models for CESEC and other computer codes, Waterford 3 operational data has been used to refine the EPU LTC model.

The following transients have recently been experienced at Waterford 3 and were utilized to confirm the accuracy of the Waterford 3 Long Term Cooling (LTC) model for EPU.

- Turbine trip from 100% power - February 14, 2003.
  The turbine trip had the steam bypass control system (SBCS) available to mitigate the transient. A reactor power cutback signal was automatically generated and quickly lowered reactor power to within the capability of the SBCS.
- Feedwater pump trip from 100% power - June 3, 2001.
  This caused a reactor power cutback to be initiated. The control systems operated as designed and there were no challenges to any of the safety systems.
- Reactor trip from approximately 82% power - February 13, 2001.
  A component failure caused turbine governor valve #3 to cycle open and closed, which caused an increase in power, and reactor trip on variable over power trip (VOPT). The plant operated as designed with feedwater and SBCS in automatic with steam generator pressure and level responding normally.

The LTC model has been benchmarked against actual plant data that was gathered at plant power levels that are relatively closer to 3716 MWth power than the power level used to benchmark the original CESEC computer code for the startup Turbine Trip test discussed below. The power level used to benchmark the CESEC code was 16% lower than startup full power. The CENTS and LTC codes have been benchmarked against a power level that is 8% lower than 3716 MWth.

As part of developing the EPU LTC models, the ability of LTC to appropriately model these pre-EPU transients was verified and documented. The LTC results compared well to the actual plant data.

Performance of a transient test as a demonstration of acceptable plant response is of very limited value, applicable only to one specific transient at one specific set of conditions. In contrast, performance of transient tests for the purpose of benchmarking a calculational model adds value in refining the fundamental relationships defined in that model. Although each additional benchmarking event improves the level of confidence in the veracity of the model, it does so, on a diminishing basis. The design of the LTC model, the historical experience with the model (at Waterford 3 and within the industry), and the baseline comparisons already performed, make it highly unlikely that a fundamental flaw exists in the LTC model. Thus, performance of additional transient tests to benchmark the LTC Code used at Waterford 3 is of limited value. Performance of additional transient tests to collect data to benchmark a calculational model is of value in improving the level of confidence in the veracity of the model. However, this value diminishes with each additional benchmark transient performed. Performing a plant transient to benchmark an already properly benchmarked model is of lesser value.

A well designed and benchmarked model may still contain an isolated flaw. However, for a test to reveal an isolated flaw, the test must be performed at the initial conditions and the specific transient sequence where the model is flawed. If the flaw is highly specific, i.e. only affects one accident scenario, then only one transient scenario at one initial condition would reveal that flaw. Without some prior knowledge of the flaw (or potential flaw), it is unlikely that a randomly selected test would reveal an isolated flaw in the model.

5. LTC Code Applicability to Changes in Operating Conditions

The LTC code is suited for evaluating changes to operating conditions. It is used to evaluate several operating conditions within a single plant design such as turbine trips from different power levels. It has been used successfully to evaluate changes in operating conditions from the original plant design. For Waterford 3, the LTC code was used to evaluate changes to the NSSS Control systems to operate at a new set of operating conditions for Thot reduction. The NSSS Control System setpoints provided by the LTC evaluation were installed in the unit and provided the expected control response without further control system changes. The LTC Code has also been used at Waterford 3 to evaluate the new set of operating conditions for the Appendix K Uprate. The evaluation proved to be satisfactory, and no additional modifications were required.

6. Proposed Plant Maneuvering Tests

Entergy plans to perform the following plant maneuvering tests as part of the post EPU startup test plan: NSSS/BOP Plant Data Record, Transient Data Record, and Load Change Test.

The NSSS/BOP Plant Data Record will demonstrate the proper performance of plant systems at various steady state conditions throughout the power range. This test provides a permanent baseline data record of plant parameter indications from zero power to full power operation, during steady state operation.

The Transient Data Record will demonstrate the proper performance of plant systems during a slow power ascension. The transient data record establishes a plant baseline data record during the slow initial power ascension. The data provides an overview of primary and secondary plant loads and operating conditions and how they change during power increases.

The Load Change Test will demonstrate the ability of the plant systems to respond to a more rapid, controlled power change. This test will demonstrate that the integrated plant control systems (SBCS, FWCS, RRS, PLCS, pressurizer pressure control system (PPCS), and DEH) operate satisfactorily in automatic to maintain plant parameters within specific limits.

These tests, when taken together, represent an integrated test of control systems through a wide range of operating conditions. More information on these proposed plant maneuvering tests can be found in Entergy letter W3F1-2004-0004, "Supplemental Information Extended Power Uprate - Power Ascension Testing," dated January 29, 2004.

Additional Discussion

1. Specific Changes Highlighted in the RAI

a. Reactor Power Cutback (RPC) and Reactor Trip on Turbine Trip (RT/TT)

No change to the RPC or the RT/TT systems is required for EPU. The permissive setpoint in the Excore Nuclear Instrument (ENI) systems which activates RT/TT is being lowered. Procedures are also being changed to place RPC or RT/TT in service at a lower power level post EPU.

RT/TT mitigates the effect of main turbine trip by tripping the reactor upon a turbine trip. This avoids challenging the Plant Protection System high pressurizer pressure trip.

RPC mitigates the effect of two transients: Loss of Load and Loss of a Feedwater Pump. The RPCS drops select Control Element Assemblies (CEA) into the core to rapidly reduce thermal power to within the capacity of the SBCS (on a loss of load), or to within the capacity of one FW Pump (on a loss of a FW Pump). Actuation of the RPC can avoid a reactor trip to facilitate continued power generation.

These systems are removed from service when they are no longer needed; specifically, when reactor thermal power is within the capacity of the SBCS (for RT/TT and RPC), and when reactor thermal power is within the capacity of one Feedwater pump (for RPC). EPU results in only a minor change (due to the slightly lower Tave) to the maximum capacity of the SBCS or FWCS. The thermal power below which RPC will be removed from service will remain consistent with the maximum capacity of the SBCS and FWCS. However, since EPU will increase rated thermal power, this value, as expressed as a percent of rated thermal power, will decrease.

RPC and RT/TT are not required systems for operation and are not credited in any safety analysis. These systems provide an additional barrier which can preclude a Plant Protection System actuation for certain transients to facilitate continued power generation (RPC only). Therefore, these systems are maintained in service per procedure. However, they may be removed from service at the operator's discretion at anytime during the cycle.

b. ADV Controller

The ADV setpoint will be changed from 1050 psig to 992 psig to support EPU. This setpoint is manually set by the operator. No aspect of the ADV controller or valve operator is being modified for EPU. To aid the operator in setting the ADV controller setpoint, the setpoint signal from the controller will be sent to the Plant Monitoring Computer (PMC). This will require the installation of an additional interfacing circuit card. A channel calibration will be performed to verify that this modification has been completed properly.
The setpoint of the ADV does affect the plant transient response, and it is modeled in the LTC Code for control systems evaluation as well as in the SBLOCA ECCS analyses where it is credited, with acceptable results.

As part of EPU, a new limit was established by engineering calculations for the separation between the ADV and SBCS setpoints. This limit provides reasonable confidence that the SBCS will actuate in response to a load rejection before the ADVs actuate (i.e. the separation limit is greater than or equal to the combined random uncertainty between the ADV control setpoint and the SBCS, including the relevant process measurement effect terms).

Additionally, this calculation change evaluates the Pre-EPU vs. Post-EPU SBCS and ADV Setpoint Configuration. This calculation concludes that with the EPU upgrades, the specified setpoints provide a higher level of assurance that the ADVs will not actuate before the SBCS than the pre-EPU conditions.

These conclusions are based on the uncertainties of the specific instruments and on the setpoints specified in this calculation change. A channel calibration of SBCS and the ADVs will validate the setpoint assumptions for EPU.

c. Main Turbine Overspeed Transient

A main turbine overspeed transient can only occur during times when the main generator is not synchronized onto the electric grid. The most likely scenario is during a sudden loss of load transient. At Waterford 3, two protective actuation features provide preemptive protection for the overspeed trip on a loss of load. Should the load be lost due to an electrical fault which causes the main generator to trip, the same relays which trip the generator also simultaneously trip the main turbine. This avoids a challenge to the turbine overspeed trip.

Should the turbine load be lost due to a grid disturbance, the Overspeed Protection Circuit (OPC) will actuate at 103% of synchronous speed to prevent a challenge to the turbine overspeed trip. The OPC closes the governor and intercept valves until speed drops below 103%.

However, should the turbine overspeed despite these protective actuations, an overspeed trip of the turbine will occur at 111% of rated speed. The new turbine-generator configuration has been evaluated and has concluded that under these conditions the maximum rotor speed achieved will be <120% of rated speed. This analysis also assumes a failure of a reverse current valve. This is significantly less than the analyzed destruction speed of 193%. The replacement rotor will be factory tested 120% of rated speed.

Additionally, the catastrophic failure of the turbine has been evaluated in FSAR section 3.5 at design overspeed (120%) and at destructive overspeed (193%). This analysis concluded that the combined probability of strike and damage due to a turbine overspeed is acceptably low.

The overshoot is a product of the delays in the protective actuations, the time for the turbine valves to close, the residual steam in the steam path and turbine, and the rotational inertia of the turbine generator. EPU effects no changes to the trip circuitry, control oil system, or turbine valves. Thus, time delays from these components are unchanged. Additionally, the steam flow path up to and downstream of the main turbine, including the turbine casing, remain unchanged. There are some dimensional changes within the HP turbine, but this results in a minimal change in the volume of the overall steam flow path. The new HP rotor has approximately 1% more rotational inertia than the original HP rotor. Thus more energy is

required to accelerate the new rotor, which would tend to reduce the maximum speed obtained during an overspeed event.

No test performed during initial startup testing demonstrated or quantified the main turbine overspeed overshoot. Performance of such a test at Waterford 3 would require defeating preemptive protective features. Unlike the normal overspeed trip test with no load on the turbine, a test to determine the main turbine overspeed overshoot would require a rapid transient, which once initiated would no longer be under the control of the operator. With the preemptive trips defeated, the consequence of a failure of the final overspeed trip would be catastrophic. Sufficient margin exists in the design of the rotor relative to high speed durability, engineering analysis demonstrates that an overspeed event will remain within design, and the changes implemented by EPU should reduce, not increase the magnitude of overspeed overshoot. Therefore, a test to demonstrate main turbine overspeed overshoot would not confirm any new or significant aspect of performance which has not already been adequately evaluated, and does not justify the risk inherent with such a test.

d. Modifications to Control Systems and Setpoints

Changes to the plant control systems are required to ensure the plant, at the new EPU operating conditions, will be maintained at desired operating bands during normal operations and will stabilize the plant during minor load changes and load rejection events. These adjustments do not change the design functions of the equipment or the method of performing or controlling the function. The changes are affected by revising program constants. Post modification testing consists of channel calibrations which demonstrate that the adjustments have been completed properly. Channel calibrations also demonstrate proper controller demand (output) for a wide range of process inputs, and that setpoint actuations occur within specified limits.

The transient response of the modified control systems and the integrated plant response during transient conditions have been evaluated using the LTC Code with acceptable results. As discussed previously, calculational methods in general are effective tools for modeling changes to control systems and various operating conditions. The LTC Code in particular is suited for evaluating changes to control systems (RRS, PLCS, SBCS, FWCS), since the algorithms in the LTC Code mimic the algorithms in those controllers. Therefore, these adjustments will not result in a significant change to the plant's dynamic response to anticipated initiating events.

2. Comparison of the transient testing performed in the original plant startup test program with the testing proposed for EPU;

TABLE 3
COMPARISON TO INITIAL STARTUP TESTS

Test #	Cycle 1 Transient Testing	Initial Power Level	EPU Test
SIT-TP-721	Load Changes	100%	Yes
SIT-TP-726	Remote Reactor Trip With Subsequent Remote Cooldown	20%	No
SIT-TP-727	80% Total Loss of Flow Test/Natural Circulation	80%	No
SIT-TP-728	Loss of Offsite Power Trip	20%	No
SIT-TP-740	100% Turbine Trip	84%	No
SIT-TP-749, 750, 751, 752, 753	Reactor Power Cutback System (RPCS) Loss of Load and Loss of Feedwater Pump Testing.	Not Performed	No
SIT-TP-755	Natural Circulation Demonstration	80%	No

In general, the indicated initial startup test (except for the Load Changes test) are not re-performed for EPU because the original test was performed from a relatively low (<100%) power level, and the changes planned for EPU do not invalidate the conclusions of those tests. The 8% Waterford 3 Extended Power Uprate developed its EPU operating point to correspond to a nominal HFP Thot value of 601°F, which is approximately the same as for current licensed conditions and less than the nominal Thot value with which Waterford 3 operated until 1992. There are no major changes to the nuclear steam supply system due to EPU. The major plant modifications as noted in Table 1 are to the turbine-generator, main transformers and switching station. As a result, Entergy believes that of these transient tests, only a load change test should be re-performed as a result of EPU. Re-performing the remaining transient tests for EPU is not necessary. If performed, such tests would not confirm any new or significant aspect of performance which has not already been demonstrated by previous operating experience or is routinely demonstrated through plant operation. Thus, there is no need to re-perform these tests at EPU conditions. Additionally, benchmarking used in refining the LTC Code for EPU was performed at a 92.5% of post EPU rated thermal power. This is closer to full power than any of the excluded tests were when performed during initial startup. Further information and justification for taking exception to these startup tests can be found in Entergy letter W3F1-2004-0004, "Supplemental Information Extended Power Uprate - Power Ascension Testing," dated January 29, 2004.

3. Industry experience with using calculational models for predicting transient response post power uprate.

Two EPU cases are discussed here: Dresden Unit 3 and ANO Unit 2. Like Waterford 3, ANO Unit 2 is a Combustion Engineering pressurized water reactor. Dresden Unit 3 is a boiling water reactor. Neither unit performed large transient testing following EPU, and relied on calculational methods to model system response in large transients. Subsequent to EPU, both units experienced transients which were then compared to the response predicted by the calculational method.

Dresden On January 24, 2004, Dresden Unit 3 experienced a Post EPU scram from 100% power during which all plant systems responded as expected. However, on January 30, 2004, Dresden Unit 3 experienced a Post-EPU scram which resulted in water entering the High Pressure Coolant Injection Steam Line. The root cause of this event was attributed to a "feedwater level control system (FWLCS) that had a low margin to accommodate changes to the post-scram vessel level response." The Dresden model was not capable of predicting the dynamic interaction between the FWLCS and other factors affecting vessel water level.

The contrasting results of these two transients illustrate a fundamental limitation of transient testing. Transient testing tests a discrete set of initial conditions that is only transferable over a range of conditions, and across differing transient scenarios by modeling. It would be erroneous to conclude from a single test that any other transient, or the same transient from a different initial condition would also yield acceptable results.

In response to the January 30th event, Dresden has implemented plant modifications and improved their modeling code through benchmarking, but plans no large transient testing.

ANO Unit 2 On December 19, 2002, ANO2 also experienced an unplanned post EPU scram. A review of the data from that transient indicated that plant performance had been adequately predicted by the calculational method which had been utilized for control systems and integrated plant transient response evaluation for EPU.

ANO Unit 2 utilizes the LTC Code, which has been benchmarked against pre-EPU plant data. Although ANO Unit 2 had planned to induce a large transient to gain data for comparison against the LTC code as part of startup testing, this test had been deferred until later in the cycle. When ANO Unit 2 had a post-EPU unplanned scram, ANO2 benchmarked their LTC code with that plant data. ANO2 concluded that this unplanned transient provided an acceptable alternative to their previously planned transient and further concluded that LTC predicted key parameters with very good accuracy, thus validating their LTC code.

4. Negative aspects inherent in any large transient test

Potential drawbacks of inducing a large transient include the potential for a crud burst (which could raise radiation levels), the possibility of inducing a Crud Induced Power Shift, and challenging the stability of electric power grid due to the rapid loss of a large generation capacity. The risks involved with challenging the electric power grid are aggravated should the transient test be performed at the end of refuel 13, during the Summer Reliability Window when demand on the grid is the highest.

Conclusion

The planned post maintenance testing and startup tests are an adequate quality check to confirm that analyses, modifications and adjustments that are necessary for EPU have been completed properly. Calculational methods have been appropriately utilized to evaluate the integrated plant response during transient conditions. The calculational method employed has been adequately benchmarked against actual plant data. Performance of a transient test as a demonstration of plant transient response is of very limited value, applicable only to one specific transient at one specific set of initial conditions. Performance of additional transient tests to collect data for use with an already properly benchmarked model is of diminishing value. Thus, performance of a large transient test is unlikely to confirm any new or significant aspect of performance which has not already been demonstrated by previous operating experience or is routinely demonstrated through plant operation. A scram, or the potential for a scram, from a high power level, results in an unnecessary and undesirable plant transient cycle on the primary system, and the risk associated with the intentional introduction of a transient initiator, while small, should not be incurred unnecessarily.