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Constellation Energy
R.E. Ginna Nuclear Power Plant

July 7, 2005

U. S. Nuclear Regulatory Commission
Washington, DC 20555

ATTENTION: Document Control Desk

SUBJECT: **R.E. Ginna Nuclear Power Plant**
Docket No. 50-244

License Amendment Request Regarding Extended Power Uprate

Pursuant to 10 CFR 50.90, R.E. Ginna Nuclear Power Plant, LLC (Ginna LLC) hereby requests an amendment of the R.E. Ginna Nuclear Power Plant (Ginna) Facility Operating License (DPR-18). The proposed amendment would increase the unit's authorized core power level from 1520 megawatts thermal (MWt) to 1775 MWt, and make changes to Technical Specifications as necessary to support operation at the higher power level. This is a 16.8% increase in power level compared to that authorized by the initial full-term operating license and is therefore defined as an Extended Power Uprate (EPU). The increase in power level is planned to be accomplished in one increment following the Fall 2006 refueling outage beginning with Cycle 33.

This planned application was the topic of public meetings between the NRC and Ginna LLC on August 18, 2004 (Accession # ML042450626 and ML042510119), February 3, 2005 (ML050450080), April 6, 2005 (ML050980075), and May 24, 2005.

This amendment request fulfills, at a minimum, the information requirements of RS-001, "Review Standard for Extended Power Uprates" (Rev. 0, December 2003), in so far as the guidance and/or criteria of the Review Standard applies to the design bases of Ginna. In addition, technical information beyond the specific guidance of RS-001 is provided and identified as such in the attached EPU Licensing Report. Also, Requests for Additional Information (RAIs) regarding power uprate applications for other pertinent plants were reviewed for applicability, and information that addresses many of those RAIs is included in the EPU Licensing Report.

Attachment 1 contains descriptions and technical justifications for the proposed Operating License and Technical Specification changes. Attachment 1 also contains the description of changes to the Updated Final Safety Analysis Report (UFSAR) that require prior NRC review and approval in accordance with 10 CFR 50.59. In accordance with 10 CFR 50.91(a)(1), Ginna LLC has performed a No Significant Hazards Consideration analysis and concludes that the changes proposed by this license amendment request present no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

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Attachment 2 contains the Operating License and Technical Specification markups to facilitate identifying the proposed changes.

Attachment 3 contains the clean re-typed Technical Specification pages.

Attachment 4 identifies the associated changes to the Technical Specification Bases. These changes are provided for information only. Following approval of the requested Operating License and Technical Specification changes, the Technical Specification Bases will be formally revised.

Attachment 5 contains the nonproprietary version of the EPU Licensing Report, formatted in accordance with RS-001, and accompanying WCAP-16461-NP, "Ginna Station Extended Power Uprate Supplemental Information" (Nonproprietary). For plant design features and analyses affected by the EPU, the Licensing Report describes Ginna's current licensing bases (CLB), and the methods, margins or operating limits, and results of the investigations that have been performed to determine the impacts of EPU on the CLB. This Licensing Report demonstrates acceptable facility operation at the increased power level.

Plant modifications necessitated by the power uprate are being implemented over time. Those that, in accordance with 10 CFR 50.59, do not require prior NRC approval, and do not prevent operation at the currently licensed power level, have already been made or will be made while the plant is on line, or no later than the next planned refueling outage in the Fall 2006. The remaining power uprate related modifications depend upon first receiving NRC's approval to change the associated Technical Specifications. These remaining modifications are planned to be made during the Fall 2006 refueling outage. A list of plant modifications associated with EPU and their implementation schedule is provided in Attachment 5, Section 1.0.

Ginna LLC is evaluating the performance of additional large plant transient tests beyond those described in Attachment 5, Section 2.12. The purpose of this detailed evaluation is to properly balance the beneficial result of any additional tests, with regard to verifying integrated plant performance, against the potential adverse plant risk associated with an unwanted transient. The current schedule for completion of this evaluation is prior to September 30, 2005, at which time Ginna LLC will inform the NRC of the results.

Attachment 6 contains the application for withholding the proprietary information contained in Attachment 7 from public disclosure. As Attachment 7 contains information proprietary to Westinghouse Electric Company LLC, it is supported by an affidavit signed by Westinghouse, the owner of the information. The affidavit sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b) (4) of Section 2.390 of the Commission's' regulations. Accordingly, it is respectfully requested that the information which is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR Section 2.390 of the Commission's regulations.

Correspondence with respect to the copyright or proprietary aspects of the items listed above or the supporting Westinghouse affidavit should reference CAW-05-2014 and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Attachment 7 contains a proprietary version of the EPU Licensing Report and accompanying WCAP-16461-P, "Ginna Station Extended Power Uprate Supplemental Information" (Proprietary).

Attachment 8 contains the Supplemental Environmental Report, which has been prepared pursuant to 10 CFR 51.

Attachment 9 contains a summary of regulatory commitments related to this submittal.

Three additional license amendment requests are required in support of this EPU submittal. These requests consist of the following changes:

- Allow the use of the Relaxed Axial Offset Control (RAOC) methodology for certain Power Distribution Limits
- Allow the use of the main feedwater isolation valves in lieu of the main feedwater pump discharge valves to provide isolation capability to the steam generators in the event of a steam line break
- Modify the volume and boron concentration requirements for the accumulators, revise the boron concentration requirements for the RWST and revise the list of referenced analytical methods specified in TS 5.6.5.b

These license amendment requests were individually submitted on April 29, 2005 (Accession # ML051300330, ML051260239, ML051260236). The approval of the EPU submittal is contingent upon the approval of these additional submittals.

In accordance with 10 CFR 50.91, a copy of this amendment application is being provided to the designated New York State official.

Approval of this amendment application is requested by August 11, 2006 so that adequate time remains to implement the power uprate changes during the Fall 2006 refueling outage.

Should you have questions regarding the information in this submittal, please contact George Wrobel at (585) 771-3535 or george.wrobel@constellation.com.

Very truly yours,

Mary G. Korsnick

Mary G. Korsnick

STATE OF NEW YORK : TO WIT:
COUNTY OF WAYNE :

I, Mary G. Korsnick, being duly sworn, state that I am Vice President – R.E. Ginna Nuclear Power Plant, LLC (Ginna LLC), and that I am duly authorized to execute and file this request on behalf of Ginna LLC. To the best of my knowledge and belief, the statements contained in this document are true and correct. To the extent that these statements are not based on my personal knowledge, they are based upon information provided by other Ginna LLC employees and/or consultants. Such information has been reviewed in accordance with company practice and I believe it to be reliable.

Mary G. Korsnick

Subscribed and sworn before me, a Notary Public in and for the State of New York and County of Monroe, this 7 day of July, 2005.

WITNESS my Hand and Notarial Seal: Sharon L Miller
Notary Public

My Commission Expires: 7-7-05
Date

SHARON L. MILLER
Notary Public, State of New York
Registration No. 01MI6017755
Monroe County
Commission Expires December 21, 2006

Attachment:
1. Analysis of Proposed Operating License, Technical Specification, and Licensing Basis Changes
2. Proposed Operating License and Technical Specification Changes (markup)
3. Revised Technical Specification Pages
4. Proposed Technical Specification Bases Changes (markup)
5. EPU Licensing Report (Nonproprietary) and WCAP-16461-NP, "Ginna Station Extended Power Uprate Supplemental Information" (Nonproprietary)*
6. Westinghouse Authorization Letter, CAW-05-2014, with Accompanying Affidavit, Proprietary Information Notice, and Copyright Notice
7. EPU Licensing Report (Proprietary) and WCAP-16461-P, "Ginna Station Extended Power Uprate Supplemental Information" (Proprietary)*
8. Supplemental Environmental Report.
9. List of Regulatory Commitments

* CD copies of the submittal will contain only one version (proprietary or nonproprietary) of the EPU Licensing Report and accompanying WCAP.

cc: S. J. Collins, NRC (letter only)
P. D. Milano, NRC
Resident Inspector, NRC (letter only)

Peter R. Smith (nonproprietary CD)
New York State Energy, Research, and Development Authority
17 Columbia Circle
Albany, NY 12203-6399

Paul Eddy (nonproprietary CD)
NYS Department of Public Service
3 Empire Plaza, 10th Floor
Albany, NY 12223-1350

Attachment 1

R.E. Ginna Nuclear Power Plant

Analysis of Proposed Operating License, Technical Specification, and Licensing Basis Changes

1.0 DESCRIPTION

This letter is a request to amend Operating License DPR-18 for the R.E Ginna Nuclear Power Plant (Ginna).

The proposed change will revise the Operating License to permit Ginna to operate at a maximum steady state reactor core thermal power of 1775 MWt. The requested increase constitutes an Extended Power Uprate (EPU) and is requested to provide greater unit electrical generating capacity. Ginna LLC requests approval of the proposed amendment by August 11, 2006. Once approved, the amendment will be implemented during restart from the refueling outage in the Fall of 2006 and operation at the increased power level will occur in Cycle 33.

Ginna LLC has also made prior NRC submittals, References 7.1, 7.2, and 7.3, which are associated with the EPU and are necessary for its implementation.

2.0 PROPOSED CHANGE

The requested change involves one revision to the Operating License and several changes to the Technical Specifications and Licensing Basis. Each change is described below and evaluated in Section 4.0 of this attachment.

Operating License change:

<u>License condition 2.C.1, Maximum Power Level</u>

It is proposed to change the maximum core power level from 1520 MWt to 1775 MWt.

Technical Specification changes are identified below. Some changes are required for the EPU and others are requested improvements that are not required to support facility operation under EPU conditions but provide additional margin with respect to the EPU. The required changes are identified as such in the description of the changes.

<u>1.1 Definitions, Rated Thermal Power</u>

Rated thermal power is changed from 1520 MWt to 1775 MWt. This is an EPU related change.

<u>LCO 3.3.1, Reactor Trip System, Actions Condition O</u>

The required thermal power value is reduced from < 50% RTP to < 30% RTP. This is an EPU related change.

<u>Table 3.3.1-1, Reactor Trip System, Functional 2.a</u>

The Power Range Neutron Flux – High Limiting Safety System Setting is reduced from ≤ 112.27% RTP to ≤ 109.27% RTP. This is an EPU related change.

Table 3.3.1-1, Reactor Trip System, Functional 16.c

The Reactor Trip System Interlocks - Power Range Neutron Flux, P-8 Limiting Safety System Setting is reduced from ≤ 49.0% RTP to ≤ 29.0% RTP. This is an EPU related change.

Table 3.3.1-1, Reactor Trip System, Footnote (h)

The referenced thermal power value is reduced from ≥ 50% RTP to ≥ 30% RTP. This is an EPU related change.

Table 3.3.2-1, ESFAS Instrumentation, Functional 1.d

The Safety Injection Pressurizer Pressure-Low Limiting Safety System Setting is reduced from ≥ 1744.8 psig to ≥ 1729.8 psig. This is a margin improvement related change.

Table 3.3.2-1, ESFAS Instrumentation, Functional 2.c

The Containment Spray Containment Pressure-High High Limiting Safety System Setting is increased from ≤ 31.11 psig to ≤ 32.11 psig (narrow range) and from ≤ 28.6 psig to ≤ 29.6 psig (wide range). This is a margin improvement related change.

Table 3.3.2-1, ESFAS Instrumentation, Functional 4.d

The Steam Line Isolation High Steam Flow Limiting Safety System Setting is increased from ≤ 0.42E6 lbm/hr @ 1005 psig to ≤ 1.30E6 lbm/hr @ 1005 psig. This is an EPU and margin improvement related change.

Table 3.3.2-1, ESFAS Instrumentation, Functional 4.d

The Steam Line Isolation Coincident with T_{avg}-Low Limiting Safety System Setting is decreased from ≥ 544.98 °F to ≥ 544.0 °F. This is a margin improvement related change.

Table 3.3.2-1, ESFAS Instrumentation, Functional 4.e

The Steam Line Isolation High-High Steam Flow Limiting Safety System Setting is increased from ≤ 3.63E6 lbm/hr @ 755 psig to ≤ 4.53E6 lbm/hr @ 785 psig. This is an EPU and margin improvement related change.

LCO 3.4.10, Pressurizer Safety Valves

The upper lift setting for the pressurizer safety valves is decreased from ≤ 2544 psig to ≤ 2542 psig. This is an EPU related change.

LCO 3.7.6, Condensate Storage Tanks (CSTs)

In Surveillance Requirement SR 3.7.6.1 the CSTs required volume listed is increased from ≥ 22,500 gallons to ≥ 24,350 gallons. This is an EPU related change.

In summary, Ginna LLC has reviewed the Operating License and Technical Specifications, and has determined that no revisions to those documents other than those noted above (or in the previously referenced submittals) are required to properly control plant operations and configuration under EPU conditions. Mark-ups of the proposed Operating License and Technical Specification changes are provided in Attachment 2 and revised (clean) Technical Specification pages are provided in Attachment 3. A copy of the proposed mark-up of the Technical Specification Bases is provided in Attachment 4 and is provided for information only.

Licensing Basis changes are identified below.

Control Room Dose Increase

The dose analysis for the EPU indicates that the control room dose for the LOCA increased from 3.51 REM TEDE to 4.6 REM TEDE, and the Rod Ejection Accident (REA) control room dose increased from 1.19 REM TEDE to 1.83 REM TEDE. These increases are above the threshold for minimal increase under 10 CFR 50.59 and will require NRC review and approval.

3.0 BACKGROUND

This requested license amendment would authorize Ginna to operate at 1775 MWt, an approximate 16.8% increase in power level compared to that authorized by the initial full-term operating license and is therefore defined as an Extended Power Uprate.

Ginna LLC has evaluated the impact of the 16.8% power uprate for the applicable systems, structures, components, and safety analyses at Ginna. The results of this evaluation are described in Attachment 5 of this letter, EPU Licensing Report. The EPU Licensing Report provides the details that support the requested Operating License, Technical Specification, and Licensing Basis changes and works in concert with the other attachments to the amendment request to provide a comprehensive evaluation of the effects of the proposed EPU.

Ginna LLC plans to implement the Ginna EPU in one increment. Completion of plant modifications necessary to implement the EPU is planned to occur prior to the end of the refueling outage in the Fall of 2006. With the approval of this license amendment request, the plant will be operated at 1775 MWt starting in Cycle 33.

4.0 TECHNICAL ANALYSIS

The acceptability of each proposed Operating License, Technical Specification, and Licensing Basis change is addressed below.

The EPU Licensing Report is contained in Attachment 5 of this license amendment request. The EPU Licensing Report summarizes the evaluations performed to assure acceptable unit operation at EPU conditions and is therefore referenced throughout this section as additional technical justification for the EPU related changes.

License condition 2.C.1, Maximum Power Level

It is proposed to change the maximum core power level from 1520 MWt to 1775 MWt. The EPU Licensing Report (Attachment 5) evaluates structural integrity, structure, system, component (SSC) performance, and facility response to small and large break LOCAs and non-LOCA events evaluated in the Ginna UFSAR, Chapter 15. The Licensing Report evaluations were performed consistent with EPU conditions and the proposed Technical Specification changes identified in Section 2.0 and evaluated below. The EPU Licensing Report evaluation results demonstrate that SSC structural limits and performance requirements are met and safety analysis results meet acceptance criteria. The environmental effects of facility operation at a core power level of 1775 MWt were evaluated in the Supplemental Environmental Report (Attachment 8) and shown to be acceptable.

1.1 Definitions, Rated Thermal Power

Rated thermal power is changed from 1520 MWt to 1775 MWt. Justification for increasing thermal power to 1775 MWt is discussed above with respect to Operating License condition 2.C.1.

LCO 3.3.1, Reactor Trip System, Actions Condition O

The required thermal power value associated with a single loop loss of coolant flow trip is reduced from < 50% RTP to < 30% RTP. The analyses performed for EPU determined that an analytical limit of ≤ 35% power is required to ensure all accidents and transients impacted by RCS flow maintain DNB within acceptable limits (Reference Attachment 5 Section 2.4.1 and 2.8.5.3.1). The value specified in the Actions Condition is based on the Reactor Trip System Interlocks - Power Range Neutron Flux, P-8 Limiting Safety System Setting (LSSS).

Table 3.3.1-1, Reactor Trip System, Functional 2.a

The Power Range Neutron Flux – High LSSS is reduced from ≤ 112.27% RTP to ≤ 109.27% RTP. EPU redefines the 100% power neutron flux levels and will impact the flux level to percent power relationship for the Power Range nuclear instruments. The EPU accident and transient analyses determined that for some accidents the analytical limit for the Power Range high power trip would need to be reduced from the current 118% to 115% which will reduce the Technical Specification LSSS accordingly (Reference Attachment 5 Section 2.4.1, 2.8.5.4.1, and 2.8.5.4.6). The calculation of the LSSS has been performed consistent with the performance based methodology approved by Amendment 85 to the Ginna Technical Specifications (Reference 7.4).

Table 3.3.1-1, Reactor Trip System, Functional 16.c

The Reactor Trip System Interlocks - Power Range Neutron Flux, P-8 LSSS, associated with a single loop loss of coolant flow trip, is reduced from ≤ 49.0% RTP to ≤ 29.0%

RTP. The analyses performed for EPU determined that an analytical limit of ≤ 35% power is required to ensure all accidents and transients impacted by RCS flow maintain DNB within acceptable limits. Therefore, the P-8 Technical Specification LSSS limit will be reduced from the current ≤ 49.0% power to ≤ 29.0% (Reference Attachment 5 Section 2.4.1 and 2.8.5.3.1). The calculation of the LSSS has been performed consistent with the performance based methodology approved by Amendment 85 to the Ginna Technical Specifications (Reference 7.4).

Table 3.3.1-1, Reactor Trip System, Footnote (h)

The referenced thermal power value is reduced from ≥ 50% RTP to ≥ 30% RTP. The analyses performed for EPU determined that a lower power level is required to ensure all accidents and transients impacted by RCS flow maintain DNB within acceptable limits (Reference Attachment 5 Section 2.4.1 and 2.8.5.3.1). The value specified in the Applicability footnote is based on the Reactor Trip System Interlocks - Power Range Neutron Flux, P-8 LSSS associated with a single loop loss of coolant flow trip.

Table 3.3.2-1, ESFAS Instrumentation, Functional 1.d

The Safety Injection Pressurizer Pressure-Low LSSS is reduced from ≥ 1744.8 psig to ≥ 1729.8 psig. In order to increase the calibration margin on ESFAS parameter related setpoints, the analytical value used in the accident and transient analyses was changed from 1715 psig to 1700 psig. Since acceptable results were achieved using this value, the value will become the basis for establishing the Technical Specification LSSS value and field setpoints (Reference Attachment 5 Section 2.4.1, 2.8.5.1.1, 2.8.5.6.2, and 2.8.5.6.3). The calculation of the LSSS has been performed consistent with the performance based methodology approved by Amendment 85 to the Ginna Technical Specifications (Reference 7.4).

Table 3.3.2-1, ESFAS Instrumentation, Functional 2.c

The Containment Spray Containment Pressure-High High LSSS is increased from ≤ 31.11 psig to ≤ 32.11 psig (narrow range) and from ≤ 28.6 psig to ≤ 29.6 psig (wide range). In order to increase the calibration margin on ESFAS parameter related setpoints, the analytical value used in the accident and transient analyses was changed from 32.5 psig to 33.5 psig. Since acceptable results were achieved using this value, the value will become the basis for establishing the Technical Specification LSSS value and field setpoints (Reference Attachment 5 Section 2.4.1 and 2.6.1). The calculation of the LSSS has been performed consistent with the performance based methodology approved by Amendment 85 to the Ginna Technical Specifications (Reference 7.4).

Table 3.3.2-1, ESFAS Instrumentation, Functional 4.d

The Steam Line Isolation High Steam Flow LSSS is increased from ≤ 0.42E6 lbm/hr @ 1005 psig to ≤ 1.30E6 lbm/hr @ 1005 psig. The analytical limit for the High Steam Flow input to Containment Main Steam Line Isolation is being changed to allow additional instrumentation calibration margin. The analytical limit will be changed from the current 0.66x10E6 lbm/hr @ 1005 psig to 1.50x10E6 lbm/hr @ 1005 psig. Since acceptable results were achieved using this value, the value will become the basis for establishing the Technical Specification LSSS value and field setpoints (Reference Attachment 5

Section 2.4.1 and 2.8.5.1.2). The calculation of the LSSS has been performed consistent with the performance based methodology approved by Amendment 85 to the Ginna Technical Specifications (Reference 7.4).

Table 3.3.2-1, ESFAS Instrumentation, Functional 4.d

The Steam Line Isolation Coincident with T_{avg}-Low LSSS is decreased from ≥ 544.98 °F to ≥ 544.0 °F. In order to increase the calibration margin on ESFAS parameter related setpoints, the analytical value used in the accident and transient analyses was changed from 543 °F to 530 °F. Since acceptable results were achieved using this value, the value will become the basis for establishing the Technical Specification LSSS value and field setpoints (Reference Attachment 5 Section 2.4.1 and 2.8.5.1.2). The calculation of the LSSS has been performed consistent with the performance based methodology approved by Amendment 85 to the Ginna Technical Specifications (Reference 7.4).

Table 3.3.2-1, ESFAS Instrumentation, Functional 4.e

The Steam Line Isolation High-High Steam Flow LSSS is increased from ≤ 3.63E6 lbm/hr @ 755 psig to ≤ 4.53E6 lbm/hr @ 785 psig. EPU redefines the high–high steam line flow analytical limit as ≤155% nominal flow. This change in assumed steam flow resulted in an increase in the Technical Specification LSSS accordingly (Reference Attachment 5 Section 2.4.1 and 2.8.5.1.2). The calculation of the LSSS has been performed consistent with the performance based methodology approved by Amendment 85 to the Ginna Technical Specifications (Reference 7.4).

LCO 3.4.10, Pressurizer Safety Valves

The upper lift setting for the pressurizer safety valves is decreased from ≤ 2544 psig to ≤ 2542 psig. A total pressurizer safety valve setpoint tolerance of -3%/+2.3% was supported in the loss of load analysis described in the EPU Licensing Report (Reference Attachment 5 Section 2.8.5.2.1). For the DNBR case and main steam system peak pressure case, the negative tolerance was applied to conservatively reduce the setpoint. For the case analyzed for peak reactor coolant system pressure, the positive tolerance was applied to conservatively increase the setpoint pressure.

LCO 3.7.6, Condensate Storage Tanks (CSTs)

In Surveillance Requirement SR 3.7.6.1, the CSTs required volume listed is increased from ≥ 22,500 gallons to ≥ 24,350 gallons. Two condensate storage tanks are used as a source of water for auxiliary feedwater operation, each of which will be able to provide the Technical Specification minimum required usable volume. This minimum useable volume for EPU operation is an inventory of 24,350 gallons to meet the plant licensing basis of decay heat removal for 2 hours after a reactor trip from full power as described in the EPU Licensing Report Section 2.5.4.5.

Control Room Dose Increase

The dose analysis for the EPU indicates that the control room dose for the LOCA increased from 3.51 REM TEDE to 4.6 REM TEDE, and the Rod Ejection Accident (REA) control room dose increased from 1.19 REM TEDE to 1.83 REM TEDE. These increases are above the threshold for minimal increase under 10 CFR 50.59 and will require NRC review and approval. The Dose Analysis for the EPU is summarized in EPU Licensing Report section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms. An increase in licensed power results in an increase in source term and, therefore, projected dose is expected to increase. Ginna LLC has calculated the dose for all of the DBAs required by Regulatory Guide 1.183, Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors, and NUREG-0800 Section 15.0.1 (SRP) Radiological Consequence Analyses Using Alternative Source Terms, Revision 0, July 2000. Doses were calculated for Exclusion Area Boundary (EAB), Low Population Zone, and Control Room for each accident. For all of the doses calculated, only the REA and LOCA control room dose exceeded the 10 percent minimal increase criteria. However, these doses are considered acceptable because they remain less than the limits established in 10CFR50.67, Accident Source Term, and the acceptance criteria contained in Regulatory guide 1.183 and SRP 15.0.1.

5.0 REGULATORY ANALYSIS

5.1 NO SIGNIFICANT HAZARDS CONSIDERATION

Ginna LLC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   The impacts of the proposed EPU on plant systems, structures, and components (SSCs) were reviewed with respect to SSC design capability, and it was determined that following completion of plant changes to support the EPU, no system, structure, or component would exceed its design conditions or limits. Evaluations supporting those conclusions were performed consistent with proposed Technical Specification changes. Consequently equipment reliability and structural integrity will not be adversely affected. Control system studies demonstrated that plant response to operational transients under EPU conditions does not significantly increase reactor trip frequency, so there will be no significant increase in the frequency of SSC challenges caused by reactor trip.

   New systems are not needed to implement the EPU, and new interactions among SSCs are not created. The EPU does not create new failure modes for existing SSCs. Modified components do not introduce new failure modes relative to those of the components in their pre-modified condition. Consequently, new initiators of previously analyzed accidents are not created.

   The fission product barriers -- fuel cladding, reactor coolant pressure boundary, and the containment building -- remain unchanged. The spectrum of previously analyzed postulated accidents and transients was evaluated, and effects on the fuel, the reactor coolant pressure boundary, and the containment were determined. These analyses were performed consistent with the proposed Technical Specification changes. The results demonstrate that existing reactor coolant pressure boundary and containment limits are met and that effects on the fuel are such that dose consequences meet existing criteria at EPU conditions.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

   Response: No.

   New systems are not required to implement the EPU, and new interactions among SSCs are not created. The EPU does not create new failure modes for existing SSCs. Modified components do not introduce failures different from those of the components in their pre-modified condition. Consequently, no new or different accident sequences arise from SSC interactions or failures.

   Training will be provided to address EPU effects, and the plant's simulator will be updated consistent with EPU conditions. Operating procedure changes are minor and do not result in any significant changes in operating philosophy. For these reasons, the EPU does not introduce human performance issues that could create new accidents or different accident sequences.

   The increase in power level does not create new fission product release paths. The fission product barriers -- fuel cladding, reactor coolant pressure boundary, and the containment building -- remain unchanged.

   Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

   Response: No.

   Structural evaluations performed at EPU conditions demonstrated that calculated loads on affected SSCs remain within their design allowables for all design basis event categories. ASME Code fatigue limits continue to be met.

   Fuel performance evaluations were performed using parameter values appropriate for a reload core operating at EPU conditions. Those evaluations demonstrate that fuel performance acceptance criteria continue to be met. Reload evaluation processes ensure that fuel in the actual Cycle 33 reload core, the first to be operated at the increased power level, will meet regulatory criteria.

LOCA and non-LOCA safety analyses were performed under EPU conditions. Emergency core cooling system performance was shown to meet the criteria of 10CFR50.46. The non-LOCA events identified in the Ginna UFSAR Chapter 15 were shown to meet existing acceptance criteria. The LOCA and non-LOCA analyses were performed consistent with the proposed Technical Specification changes.

The containment building response to mass and energy releases was evaluated under EPU conditions. The evaluations showed that temperature and pressure limits were met.

No plant changes associated with the EPU reduce the degree of component or system redundancy. Existing Technical Specification operability and surveillance requirements are not reduced by the proposed changes, thus no margins of safety are reduced.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, Ginna LLC concludes that the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

5.2 APPLICABLE REGULATORY REQUIREMENTS/CRITERIA

The proposed changes have been evaluated to determine whether applicable regulations and requirements continue to be met.

Ginna LLC has determined that the proposed changes do not require any exemptions or relief from regulatory requirements, other than the Operating License, and do not affect conformance with any General Design Criterion (GDC) differently than described in the Updated Final Safety Analysis Report (UFSAR).

6.0 ENVIRONMENTAL EVALUATION

The environmental considerations evaluation is contained in Attachment 8, Supplemental Environmental Report. It concludes that EPU will not result in a significant change in nonradiological impacts on land use, water use, waste discharges, terrestrial and aquatic biota, transmission facilities, or social and economic factors, and will have no nonradiological environmental impacts other than those evaluated in the Supplemental Environmental Report. The Supplemental Environmental Report further concludes that EPU will not introduce any new radiological release pathways, will not result in a significant increase in occupational or public radiation exposures, and will not result in significant additional fuel cycle environmental impacts.

Therefore, the proposed amendment does not involve a significant change in the types or significant increase in the amounts of any effluent that may be released offsite nor does it involve a significant increase in individual or cumulative occupational radiation exposure.

7.0 REFERENCES

7.1 Letter from Mary G. Korsnick (Ginna LLC) to Donna M. Skay (NRC), "License Amendment Request Regarding Revised Loss of Coolant Accident (LOCA) Analyses – Changes to Accumulator, Refueling Water Storage (RWST), and Administrative Control Technical Specifications", dated April 29, 2005.

7.2 Letter from Mary G. Korsnick (Ginna LLC) to Donna M. Skay (NRC), "License Amendment Request Regarding Main Feedwater Isolation Valves", dated April 29, 2005.

7.3 Letter from Mary G. Korsnick (Ginna LLC) to Donna M. Skay (NRC), "License Amendment Request Regarding Adoption of Relaxed Axial Offset Control (RAOC)", dated April 29, 2005.

7.4 Letter from Robert Clark (NRC) to Mary G. Korsnick (Ginna LLC), "R. E. Ginna Nuclear Power Plant - AMENDMENT RE: REVISION TO CORE SAFETY LIMITS AND SAFETY SYSTEM INSTRUMENTATION SETPOINTS (TAC NO. MB4789)", dated September 22, 2004.

Attachment 2

R.E. Ginna Nuclear Power Plant

Proposed Operating License and Technical Specification Changes (markup)

(b) Pursuant to the Act and 10 CFR Part 70, to possess and use four (4) mixed oxide fuel assemblies in accordance with the RG&E's application dated December 14, 1979 (transmitted by letter dated December 20, 1979), as supplemented February 20, 1980 and March 5, 1980;

(3) Pursuant to the Act and 10 CFR Parts 30, 40, and 70 to receive, possess, and use at any time any byproduct, source, and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use in amounts as required any byproduct, source, or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) Pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This renewed license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; and is subject to all applicable provisions of the Act and rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified below:

(1) Maximum Power Level

Ginna LLC is authorized to operate the facility at steady-state power levels up to a maximum of ~~1520~~ megawatts (thermal).

1775

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 84, are hereby incorporated in the renewed license. The licensee shall operate the facility in accordance with the Technical Specifications.

(3) Fire Protection

(a) The licensee shall implement and maintain in effect all fire protection features described in the licensee's submittals referenced in and as approved or modified by the NRC's Fire Protection Safety Evaluation (SE) dated February 14, 1979 and

PHYSICS TESTS

PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are:

a. Described in Chapter 14, Initial Test Program of the UFSAR;

b. Authorized under the provisions of 10 CFR 50.59; or

c. Otherwise approved by the Nuclear Regulatory Commission (NRC).

PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

The PTLR is the plant specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, and the power operated relief valve lift settings and enable temperature associated with the Low Temperature Overpressurization Protection System for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.6. Plant operation within these limits is addressed in individual specifications.

QUADRANT POWER TILT RATIO (QPTR)

QPTR shall be the ratio of the highest average nuclear power in any quadrant to the average nuclear power in the four quadrants.

RATED THERMAL POWER (RTP)

RTP shall be a total reactor core heat transfer rate to the reactor coolant of ~~1520~~ 1775 MWt.

SHUTDOWN MARGIN (SDM)

SDM shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming:

a. All rod cluster control assemblies (RCCAs) are fully inserted except for the single RCCA of highest reactivity worth, which is assumed to be fully withdrawn. With any RCCAs not capable of being fully inserted, the reactivity worth of the RCCAs must be accounted for in the determination of SDM; and

b. In MODES 1 and 2, the fuel and moderator temperatures are changed to the nominal hot zero power temperature.

STAGGERED TEST BASIS

A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during *n* Surveillance Frequency intervals, where *n* is the total number of systems, subsystems, channels, or other designated components in the associated function.

CONDITION		REQUIRED ACTION		COMPLETION TIME
K.	As required by Required Action A.1 and referenced by Table 3.3.1-1.	K.1	------------------ - NOTE - The inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels. ------------------ Place channel in trip.	6 hours
L.	Required Action and associated Completion Time of Condition K not met.	L.1	Reduce THERMAL POWER to < 8.5% RTP.	6 hours
M.	As required by Required Action A.1 and referenced by Table 3.3.1-1.	M.1	------------------ - NOTE - The inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels. ------------------ Place channel in trip.	6 hours
N.	As required by Required Action A.1 and referenced by Table 3.3.1-1.	N.1	Restore channel to OPERABLE status.	6 hours
O.	Required Action and associated Completion Time of Condition M or N not met.	O.1	Reduce THERMAL POWER to < 50% RTP. 30	6 hours
P.	As required by Required Action A.1 and referenced by Table 3.3.1-1.	P.1	------------------ - NOTE - The inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels. ------------------ Place channel in trip.	6 hours

Table 3.3.1-1
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	LIMITING SAFETY SYSTEM SETTINGS[a]
1. Manual Reactor Trip	1, 2, 3[b], 4[b], 5[b]	2	B,C	SR 3.3.1.11	NA
2. Power Range Neutron Flux					
a. High	1, 2	4	D,G	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.7 SR 3.3.1.10	109.27 ≤ ~~112.27~~% RTP
b. Low	1[c], 2	4	D,G	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.10	≤ 29.28% RTP
3. Intermediate Range Neutron Flux	1[c], 2	2	E,G	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.10	(d)
4. Source Range Neutron Flux	2[e]	2	F,G	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.10	(d)
	3[b], 4[b], 5[b]	2	H,I	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	(d)
	3[f], 4[f], 5[f]	1	J	SR 3.3.1.1 SR 3.3.1.10	NA
5. Overtemperature ΔT	1, 2	4	D,G	SR 3.3.1.1 SR 3.3.1.3 SR 3.3.1.6 SR 3.3.1.7 SR 3.3.1.10	Refer to Note 1

Table 3.3.1-1
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	LIMITING SAFETY SYSTEM SETTINGS[a]
16. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	2[e]	2	S,V	SR 3.3.1.10 SR 3.3.1.13	≥ 5E-11 amp
b. Low Power Reactor Trips Block, P-7	1[g]	4 (power range only)	S,V	SR 3.3.1.10 SR 3.3.1.13	≤ 8.0% RTP
c. Power Range Neutron Flux, P-8	1[h]	4	S,V	SR 3.3.1.10 SR 3.3.1.13	29.0 ≤ ~~40.0~~% RTP
d. Power Range Neutron Flux, P-9	1[l]	4	S,V	SR 3.3.1.10 SR 3.3.1.13	≤ 50.0% RTP
	1[k]	4	S,V	SR 3.3.1.10 SR 3.3.1.13	≤ 8.0% RTP
e. Power Range Neutron Flux, P-10	1[c], 2	4	S,V	SR 3.3.1.10 SR 3.3.1.13	≥ 6.0% RTP
17. Reactor Trip Breakers[m]	1, 2 3[b], 4[b], 5[b]	2 trains 2 trains	T,V W,X	SR 3.3.1.4 SR 3.3.1.4	NA NA
18. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	1, 2 3[b], 4[b], 5[b]	1 each per RTB 1 each per RTB	U,V W,X	SR 3.3.1.4 SR 3.3.1.4	NA NA
19. Automatic Trip Logic	1, 2 3[b], 4[b], 5[b]	2 trains 2 trains	R,V W,X	SR 3.3.1.5 SR 3.3.1.5	NA NA

(a) A channel is OPERABLE when both of the following conditions are met:

1. The absolute difference between the as-found Trip Setpoint (TSP) and the previous as-left TSP is within the COT Acceptance Criteria. The COT Acceptance Criteria is defined as:

   |as-found TSP - previous as-left TSP| ≤ COT uncertainty

   The COT uncertainty shall not include the calibration tolerance.

2. The as-left TSP is within the established calibration tolerance band about the nominal TSP. The nominal TSP is the desired setting and shall not exceed the Limiting Safety System Setting (LSSS). The LSSS and the established calibration tolerance band are defined in accordance with the Ginna Instrument Setpoint Methodology. The channel is considered operable even if the as-left TSP is non-conservative with respect to the LSSS provided that the as-left TSP is within the established calibration tolerance band.

(b) With Control Rod Drive (CRD) System capable of rod withdrawal or all rods not fully inserted.

(c) THERMAL POWER < 6% RTP.

(d) UFSAR Table 7.2-3.

(e) Both Intermediate Range channels < 5E-11 amps.

(f) With CRD System incapable of withdrawal and all rods fully inserted. In this condition, the Source Range Neutron Flux function does not provide a reactor trip, only indication.

(g) THERMAL POWER ≥ 8.5% RTP.

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(h) THERMAL POWER ≥ 50% RTP.

(i) THERMAL POWER ≥ 8.5% RTP and Reactor Coolant Flow-Low (Single Loop) trip Function blocked.

(j) THERMAL POWER ≥ 8.5% RTP and RCP Breaker Position (Single Loop) trip Function blocked.

(k) THERMAL POWER > 8% RTP, and either no circulating water pump breakers closed, or condenser vacuum ≤ 20".

(l) THERMAL POWER ≥ 50% RTP, 1 of 2 circulating water pump breakers closed, and condenser vacuum > 20".

(m) Including any reactor trip bypass breakers that are racked in and closed for bypassing an RTB.

Table 3.3.2-1
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	LIMITING SAFETY SYSTEM SETTINGS[a]
1. Safety Injection					
a. Manual Initiation	1,2,3,4	2	D,G	SR 3.3.2.4	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	I,K	SR 3.3.2.7	NA
c. Containment Pressure-High	1,2,3,4	3	J,K	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	≤ 4.61 psig
d. Pressurizer Pressure-Low	1,2,3[b]	3	L,M	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5 SR 3.3.2.6	1729.8 ≥ ~~1744.8~~ psig
e. Steam Line Pressure-Low	1,2,3[b]	3 per steam line	L,M	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5 SR 3.3.2.6	≥ 393.8 psig

Table 3.3.2-1
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	LIMITING SAFETY SYSTEM SETTINGS[a]
2. Containment Spray					
a. Manual Initiation					
Left pushbutton	1,2,3,4	1	H,K	SR 3.3.2.4	NA
Right pushbutton	1,2,3,4	1	H,K	SR 3.3.2.4	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	I,K	SR 3.3.2.7	NA
c. Containment Pressure-High High	1,2,3,4	3 per set	J,K	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5 29.6	32.11 ≤ ~~31.11~~ psig (narrow range) ≤ ~~28.6~~ psig (wide range)
3. Containment Isolation					
a. Manual Initiation	1,2,3,4,(c)	2	H,K	SR 3.3.2.4	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	I,K	SR 3.3.2.7	NA
c. Safety Injection	Refer to Function 1 (Safety Injection) for all automatic initiation functions and requirements.				

Table 3.3.2-1
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	LIMITING SAFETY SYSTEM SETTINGS[a]
4. Steam Line Isolation					
a. Manual Initiation	1,2[d],3[d]	1 per loop	D,G	SR 3.3.2.4	NA
b. Automatic Actuation Logic and Actuation Relays	1,2[d],3[d]	2 trains	E,G	SR 3.3.2.7	NA
c. Containment Pressure-High High	1,2[d],3[d]	3	F,G	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	≤ 18.0 psig
d. High Steam Flow	1,2[d],3[d]	2 per steam line	F,G	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	1.30 ≤ ~~0.42~~E6 lbm/hr @ 1005 psig
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
and					
Coincident with T_{avg}-Low	1,2[d],3[d]	2 per loop	F,G	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	544.0 ≥ ~~544.98~~°F
e. High-High Steam Flow	1,2[d],3[d]	2 per steam line	F,G	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	4.59 ≤ ~~3.63~~E6 lbm/hr @ ~~755~~ psig 785
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 Pressurizer Safety Valves

LCO 3.4.10 Two pressurizer safety valves shall be OPERABLE with lift settings ≥ 2410 psig and ≤ ~~2544~~ psig.

2542

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 with all RCS cold leg temperatures greater than the LTOP enable temperature specified in the PTLR.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One pressurizer safety valve inoperable.	A.1 Restore valve to OPERABLE status.	15 minutes
B. Required Action and associated Completion Time not met. <u>OR</u> Both pressurizer safety valves inoperable.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 4 with any RCS cold leg temperature less than or equal to the LTOP enable temperature specified in the PTLR.	6 hours 12 hours

3.7 PLANT SYSTEMS

3.7.6 Condensate Storage Tanks (CSTs)

LCO 3.7.6 The CSTs shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. CST water volume not within limit.	A.1 Verify by administrative means OPERABILITY of backup water supply.	4 hours
	AND	
	A.2 Restore CST water volume to within limit.	7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.6.1	Verify the CST water volume is ≥ ~~22,500~~ gal. 24,350	12 hours

Attachment 3

R.E. Ginna Nuclear Power Plant

Revised Technical Specification Pages

1.0 USE AND APPLICATION

1.1 Definitions

- NOTE -

The defined terms of this section appear in capitalized type and are applicable throughout these Technical Specifications and Bases.

Term	Definition
ACTIONS	ACTIONS shall be that part of a Specification that prescribes Required Actions to be taken under designated Conditions within specified Completion Times.
ACTUATION LOGIC TEST	An ACTUATION LOGIC TEST shall be the application of various simulated or actual input combinations in conjunction with each possible interlock logic state and the verification of the required logic output. The ACTUATION LOGIC TEST, as a minimum, shall include a continuity check of output devices.
AXIAL FLUX DIFFERENCE (AFD)	AFD shall be the difference in normalized flux signals between the top and bottom halves of a two section excore neutron detector.
CHANNEL CALIBRATION	A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel so that it responds within the required range and accuracy to known input. The CHANNEL CALIBRATION shall encompass the entire channel, including the required sensor, alarm, interlock, display, and trip functions. Calibration of instrument channels with resistance temperature detector (RTD) or thermocouple sensors may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel. The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping calibrations or total channel steps so that the entire channel is calibrated.
CHANNEL CHECK	A CHANNEL CHECK shall be the qualitative assessment, by observation, of channel behavior during operation. This determination shall include, where possible, comparison of the channel indication and status to other indications or status derived from independent instrument channels measuring the same parameter.

CHANNEL OPERATIONAL TEST (COT)	A COT shall be the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify the OPERABILITY of required alarm, interlock, display, and trip functions. The COT shall include adjustments, as necessary, of the required alarm, interlock, and trip setpoints so that the setpoints are within the required range and accuracy.
CORE ALTERATIONS	CORE ALTERATIONS shall be the movement of any fuel, sources, or reactivity control components, within the reactor vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe position.
CORE OPERATING LIMITS REPORT (COLR)	The COLR is the plant specific document that provides cycle specific parameter limits for the current reload cycle. These cycle specific parameter limits shall be determined for each reload cycle in accordance with Specification 5.6.5. Plant operation within these limits is addressed in individual Specifications.
DOSE EQUIVALENT I-131	DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microcuries/gram) that alone would produce the same thyroid dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The thyroid dose conversion factors used for this calculation shall be those listed in ICRP 30, Supplement to Part 1, pages 192-212, table entitled, "Committed Dose Equivalent in Target Organs or Tissues per Intake of Unit Activity."
$\bar{E}$ - AVERAGE DISINTEGRATION ENERGY	$\bar{E}$ shall be the average (weighted in proportion to the concentration of each radionuclide in the reactor coolant at the time of sampling) of the sum of the average beta and gamma energies (in MeV) per disintegration for non-iodine isotopes, with half lives > 15 minutes, making up at least 95% of the total non-iodine activity in the coolant.

LEAKAGE

LEAKAGE from the RCS shall be:

a. Identified LEAKAGE

1. LEAKAGE, such as that from pump seals or valve packing (except reactor coolant pump (RCP) seal water injection or return), that is captured and conducted to collection systems or a sump or collecting tank;

2. LEAKAGE into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary LEAKAGE; or

3. Reactor Coolant System (RCS) LEAKAGE through a steam generator (SG) to the Secondary System;

b. Unidentified LEAKAGE

All LEAKAGE (except RCP seal water injection or return) that is not identified LEAKAGE;

c. Pressure Boundary LEAKAGE

LEAKAGE (except SG LEAKAGE) through a nonisolable fault in an RCS component body, pipe wall, or vessel wall.

MODE
- MODES

A MODE shall correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.

OPERABLE
- OPERABILITY

A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).

PHYSICS TESTS	PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are: a. Described in Chapter 14, Initial Test Program of the UFSAR; b. Authorized under the provisions of 10 CFR 50.59; or c. Otherwise approved by the Nuclear Regulatory Commission (NRC).
PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)	The PTLR is the plant specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, and the power operated relief valve lift settings and enable temperature associated with the Low Temperature Overpressurization Protection System for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.6. Plant operation within these limits is addressed in individual specifications.
QUADRANT POWER TILT RATIO (QPTR)	QPTR shall be the ratio of the highest average nuclear power in any quadrant to the average nuclear power in the four quadrants.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 1775 MWt.
SHUTDOWN MARGIN (SDM)	SDM shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming: a. All rod cluster control assemblies (RCCAs) are fully inserted except for the single RCCA of highest reactivity worth, which is assumed to be fully withdrawn. With any RCCAs not capable of being fully inserted, the reactivity worth of the RCCAs must be accounted for in the determination of SDM; and b. In MODES 1 and 2, the fuel and moderator temperatures are changed to the nominal hot zero power temperature.
STAGGERED TEST BASIS	A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during *n* Surveillance Frequency intervals, where *n* is the total number of systems, subsystems, channels, or other designated components in the associated function.

THERMAL POWER	THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.
TRIP ACTUATING DEVICE OPERATIONAL TEST (TADOT)	A TADOT shall consist of operating the trip actuating device and verifying the OPERABILITY of required alarm, interlock, display, and trip functions. The TADOT shall include adjustment, as necessary, of the trip actuating device so that it actuates at the required setpoint within the required accuracy.

Table 1.1-1
MODES

MODE	TITLE	REACTIVITY CONDITION (k_{eff})	% RATED THERMAL POWER[a]	AVERAGE REACTOR COOLANT TEMPERATURE (°F)
1	Power Operation	≥ 0.99	> 5	NA
2	Startup	≥ 0.99	≤ 5	NA
3	Hot Shutdown	< 0.99	NA	≥ 350
4	Hot Standby[b]	< 0.99	NA	$350 > T_{avg} > 200$
5	Cold Shutdown[b]	< 0.99	NA	≤ 200
6	Refueling[c]	NA	NA	NA

(a) Excluding decay heat.

(b) All reactor vessel head closure bolts fully tensioned.

(c) One or more reactor vessel head closure bolts less than fully tensioned.

3.3 INSTRUMENTATION

3.3.1 Reactor Trip System (RTS) Instrumentation

LCO 3.3.1 The RTS instrumentation for each Function in Table 3.3.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1-1.

ACTIONS

- NOTE -

Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one channel inoperable. OR Two source range channels inoperable.	A.1 Enter the Condition referenced in Table 3.3.1-1 for the channel(s).	Immediately
B. As required by Required Action A.1 and referenced by Table 3.3.1-1.	B.1 Restore channel to OPERABLE status.	48 hours
C. Required Action and associated Completion Time of Condition B not met.	C.1 Be in MODE 3.	6 hours
	AND	
	C.2 Initiate action to fully insert all rods.	6 hours
	AND	
	C.3 Place Control Rod Drive System in a condition incapable of rod withdrawal.	7 hours

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. As required by Required Action A.1 and referenced by Table 3.3.1-1.	D.1	- NOTE - The inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels. Place channel in trip.	6 hours
E. As required by Required Action A.1 and referenced by Table 3.3.1-1.	E.1	Reduce THERMAL POWER to < 5E-11 amps.	2 hours
	<u>OR</u>		
	E.2	- NOTE - Required Action E.2 is not applicable when: a. Two channels are inoperable, or b. THERMAL POWER is < 5E-11 amps. Increase THERMAL POWER to ≥ 8% RTP.	2 hours
F. As required by Required Action A.1 and referenced by Table 3.3.1-1.	F.1	Open RTBs and RTBBs upon discovery of two inoperable channels.	Immediately upon discovery of two inoperable channels
	<u>AND</u>		
	F.2	Suspend operations involving positive reactivity additions.	Immediately
	<u>AND</u>		
	F.3	Restore channel to OPERABLE status.	48 hours

CONDITION		REQUIRED ACTION		COMPLETION TIME
G.	Required Action and associated Completion Time of Condition D, E, or F is not met.	G.1	Be in MODE 3.	6 hours
H.	As required by Required Action A.1 and referenced by Table 3.3.1-1.	H.1	Restore at least one channel to OPERABLE status upon discovery of two inoperable channels.	1 hour from discovery of two inoperable channels
		<u>AND</u>		
		H.2	Suspend operations involving positive reactivity additions.	Immediately
		<u>AND</u>		
		H.3	Restore channel to OPERABLE status.	48 hours
I.	Required Action and associated Completion Time of Condition H not met.	I.1	Initiate action to fully insert all rods.	Immediately
		<u>AND</u>		
		I.2	Place the Control Rod Drive System in a condition incapable of rod withdrawal.	1 hour
J.	As required by Required Action A.1 and referenced by Table 3.3.1-1.	J.1	Suspend operations involving positive reactivity additions.	Immediately
		<u>AND</u>		
		J.2	Perform SR 3.1.1.1.	12 hours <u>AND</u> Once per 12 hours thereafter

CONDITION	REQUIRED ACTION		COMPLETION TIME
K. As required by Required Action A.1 and referenced by Table 3.3.1-1.	K.1	- NOTE - The inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels. Place channel in trip.	6 hours
L. Required Action and associated Completion Time of Condition K not met.	L.1	Reduce THERMAL POWER to < 8.5% RTP.	6 hours
M. As required by Required Action A.1 and referenced by Table 3.3.1-1.	M.1	- NOTE - The inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels. Place channel in trip.	6 hours
N. As required by Required Action A.1 and referenced by Table 3.3.1-1.	N.1	Restore channel to OPERABLE status.	6 hours
O. Required Action and associated Completion Time of Condition M or N not met.	O.1	Reduce THERMAL POWER to < 30% RTP.	6 hours
P. As required by Required Action A.1 and referenced by Table 3.3.1-1.	P.1	- NOTE - The inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels. Place channel in trip.	6 hours

CONDITION	REQUIRED ACTION	COMPLETION TIME
Q. Required Action and Associated Completion Time of Condition P not met.	Q.1 Reduce THERMAL POWER to < 50% RTP. <u>AND</u> Q.2.1 Verify Steam Dump System is OPERABLE. <u>OR</u> Q.2.2 Reduce THERMAL POWER to < 8% RTP.	6 hours 7 hours 7 hours
R. As required by Required Action A.1 and referenced by Table 3.3.1-1.	R.1 ------------------ - NOTE - One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ------------------ Restore train to OPERABLE status.	6 hours
S. As required by Required Action A.1 and referenced by Table 3.3.1-1.	S.1 Verify interlock is in required state for existing plant conditions. <u>OR</u> S.2 Declare associated RTS Function channel(s) inoperable.	1 hour 1 hour

CONDITION	REQUIRED ACTION	COMPLETION TIME
T. As required by Required Action A.1 and referenced by Table 3.3.1-1.	T.1 ------------------ - NOTE - 1. One train may be bypassed for up to 2 hours for surveillance testing, provided the other train is OPERABLE. 2. One RTB may be bypassed for up to 6 hours for maintenance on undervoltage or shunt trip mechanisms, provided the other train is OPERABLE. ------------------ Restore train to OPERABLE status.	1 hour
U. As required by Required Action A.1 and referenced by Table 3.3.1-1.	U.1 Restore at least one trip mechanism to OPERABLE status upon discovery of two RTBs with inoperable trip mechanisms.	1 hour from discovery of two inoperable trip mechanisms
	<u>AND</u>	
	U.2 Restore trip mechanism to OPERABLE status.	48 hours
V. Required Action and associated Completion Time of Condition R, S, T, or U not met.	V.1 Be in MODE 3.	6 hours
W. As required by Required Action A.1 and referenced by Table 3.3.1-1.	W.1 Restore at least one trip mechanism to OPERABLE status upon discovery of two RTBs with inoperable trip mechanisms.	1 hour from discovery of two inoperable trip mechanisms
	<u>AND</u>	

CONDITION	REQUIRED ACTION	COMPLETION TIME
	W.2 Restore trip mechanism or train to OPERABLE status.	48 hours
X. Required Action and associated Completion Time of Condition W not met.	X.1 Initiate action to fully insert all rods. AND X.2 Place the Control Rod Drive System in a Condition incapable of rod withdrawal.	Immediately 1 hour

SURVEILLANCE REQUIREMENTS

- NOTE -
Refer to Table 3.3.1-1 to determine which SRs apply for each RTS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.1.2	- NOTE - Required to be performed within 12 hours after THERMAL POWER is ≥ 50% RTP. Compare results of calorimetric heat balance calculation to Nuclear Instrumentation System (NIS) channel output and adjust if calorimetric power is > 2% higher than indicated NIS power.	 24 hours
SR 3.3.1.3	- NOTE - 1. Required to be performed within 7 days after THERMAL POWER is ≥ 50% RTP but prior to exceeding 90% RTP following each refueling and if the Surveillance has not been performed within the last 31 EFPD. 2. Performance of SR 3.3.1.6 satisfies this SR. Compare results of the incore detector measurements to NIS AFD and adjust if absolute difference is ≥ 3%.	 31 effective full power days (EFPD)

SURVEILLANCE		FREQUENCY
SR 3.3.1.4	Perform TADOT.	31 days on a STAGGERED TEST BASIS
SR 3.3.1.5	Perform ACTUATION LOGIC TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.1.6	- NOTE - Not required to be performed until 7 days after THERMAL POWER is ≥ 50% RTP, but prior to exceeding 90% RTP following each refueling. Calibrate excore channels to agree with incore detector measurements.	92 EFPD
SR 3.3.1.7	- NOTE - Not required to be performed for source range instrumentation prior to entering MODE 3 from MODE 2 until 4 hours after entering MODE 3. Perform COT.	92 days
SR 3.3.1.8	- NOTE - 1. Not required for power range and intermediate range instrumentation until 4 hours after reducing power < 6% RTP. 2. Not required for source range instrumentation until 4 hours after reducing power < 5E-11 amps. Perform COT.	92 days
SR 3.3.1.9	- NOTE - Setpoint verification is not required. Perform TADOT.	92 days

	SURVEILLANCE	FREQUENCY
SR 3.3.1.10	- NOTE - Neutron detectors are excluded. Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.11	Perform TADOT.	24 months
SR 3.3.1.12	- NOTE - Setpoint verification is not required. Perform TADOT.	Prior to reactor startup if not performed within previous 31 days
SR 3.3.1.13	Perform COT.	24 months

Table 3.3.1-1
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	LIMITING SAFETY SYSTEM SETTINGS[(a)]
1. Manual Reactor Trip	1, 2, 3[(b)], 4[(b)], 5[(b)]	2	B,C	SR 3.3.1.11	NA
2. Power Range Neutron Flux					
a. High	1, 2	4	D,G	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.7 SR 3.3.1.10	≤ 109.27% RTP
b. Low	1[(c)], 2	4	D,G	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.10	≤ 29.28% RTP
3. Intermediate Range Neutron Flux	1[(c)], 2	2	E,G	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.10	(d)
4. Source Range Neutron Flux	2[(e)]	2	F,G	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.10	(d)
	3[(b)], 4[(b)], 5[(b)]	2	H,I	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	(d)
	3[(f)], 4[(f)], 5[(f)]	1	J	SR 3.3.1.1 SR 3.3.1.10	NA
5. Overtemperature ΔT	1, 2	4	D,G	SR 3.3.1.1 SR 3.3.1.3 SR 3.3.1.6 SR 3.3.1.7 SR 3.3.1.10	Refer to Note 1

Table 3.3.1-1
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	LIMITING SAFETY SYSTEM SETTINGS(a)
6. Overpower ΔT	1, 2	4	D,G	SR 3.3.1.1 SR 3.3.1.3 SR 3.3.1.6 SR 3.3.1.7 SR 3.3.1.10	Refer to Note 2
7. Pressurizer Pressure					
a. Low	1(g)	4	K,L	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥ 1791.3 psig
b. High	1, 2	3	D,G	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤ 2396.2 psig
8. Pressurizer Water Level-High	1, 2	3	D,G	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤ 96.47%
9. Reactor Coolant Flow-Low					
a. Single Loop	1(h)	3 per loop	M,O	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥ 89.86%
b. Two Loops	1(i)	3 per loop	K,L	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥ 89.86%
10. Reactor Coolant Pump (RCP) Breaker Position					
a. Single Loop	1(h)	1 per RCP	N,O	SR 3.3.1.11	NA
b. Two Loops	1(i)	1 per RCP	K,L	SR 3.3.1.11	NA

Table 3.3.1-1
Reactor Trip System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	LIMITING SAFETY SYSTEM SETTINGS[a]
11.	Undervoltage-Bus 11A and 11B	1[g]	2 per bus	K,L	SR 3.3.1.9 SR 3.3.1.10	(d)
12.	Underfrequency-Bus 11A and 11B	1[g]	2 per bus	K,L	SR 3.3.1.9 SR 3.3.1.10	≥ 57.5 HZ
13.	Steam Generator (SG) Water Level-Low Low	1, 2	3 per SG	D,G	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥ 13.88%
14.	Turbine Trip					
	a. Low Autostop Oil Pressure	1[k][l]	3	P,Q	SR 3.3.1.10 SR 3.3.1.12	(d)
	b. Turbine Stop Valve Closure	1[k][l]	2	P,Q	SR 3.3.1.12	NA
15.	Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)	1, 2	2	R,V	SR 3.3.1.11	NA

Table 3.3.1-1
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	LIMITING SAFETY SYSTEM SETTINGS(a)
16. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	2(e)	2	S,V	SR 3.3.1.10 SR 3.3.1.13	≥ 5E-11 amp
b. Low Power Reactor Trips Block, P-7	1(g)	4 (power range only)	S,V	SR 3.3.1.10 SR 3.3.1.13	≤ 8.0% RTP
c. Power Range Neutron Flux, P-8	1(h)	4	S,V	SR 3.3.1.10 SR 3.3.1.13	≤ 29.0% RTP
d. Power Range Neutron Flux, P-9	1(i)	4	S,V	SR 3.3.1.10 SR 3.3.1.13	≤ 50.0% RTP
	1(k)	4	S,V	SR 3.3.1.10 SR 3.3.1.13	≤ 8.0% RTP
e. Power Range Neutron Flux, P-10	1(c), 2	4	S,V	SR 3.3.1.10 SR 3.3.1.13	≥ 6.0% RTP
17. Reactor Trip Breakers(m)	1, 2 3(b), 4(b), 5(b)	2 trains 2 trains	T,V W,X	SR 3.3.1.4 SR 3.3.1.4	NA NA
18. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	1, 2 3(b), 4(b), 5(b)	1 each per RTB 1 each per RTB	U,V W,X	SR 3.3.1.4 SR 3.3.1.4	NA NA
19. Automatic Trip Logic	1, 2 3(b), 4(b), 5(b)	2 trains 2 trains	R,V W,X	SR 3.3.1.5 SR 3.3.1.5	NA NA

(a)

A channel is OPERABLE when both of the following conditions are met:

1. The absolute difference between the as-found Trip Setpoint (TSP) and the previous as-left TSP is within the COT Acceptance Criteria. The COT Acceptance Criteria is defined as:

   |as-found TSP - previous as-left TSP| ≤ COT uncertainty

   The COT uncertainty shall not include the calibration tolerance.

2. The as-left TSP is within the established calibration tolerance band about the nominal TSP. The nominal TSP is the desired setting and shall not exceed the Limiting Safety System Setting (LSSS). The LSSS and the established calibration tolerance band are defined in accordance with the Ginna Instrument Setpoint Methodology. The channel is considered operable even if the as-left TSP is non-conservative with respect to the LSSS provided that the as-left TSP is within the established calibration tolerance band.

(b) With Control Rod Drive (CRD) System capable of rod withdrawal or all rods not fully inserted.

(c) THERMAL POWER < 6% RTP.

(d) UFSAR Table 7.2-3.

(e) Both Intermediate Range channels < 5E-11 amps.

(f) With CRD System incapable of withdrawal and all rods fully inserted. In this condition, the Source Range Neutron Flux function does not provide a reactor trip, only indication.

(g) THERMAL POWER ≥ 8.5% RTP.

(h) THERMAL POWER ≥ 30% RTP.

(i) THERMAL POWER ≥ 8.5% RTP and Reactor Coolant Flow-Low (Single Loop) trip Function blocked.

(j) THERMAL POWER ≥ 8.5% RTP and RCP Breaker Position (Single Loop) trip Function blocked.

(k) THERMAL POWER > 8% RTP, and either no circulating water pump breakers closed, or condenser vacuum ≤ 20".

(l) THERMAL POWER ≥ 50% RTP, 1 of 2 circulating water pump breakers closed, and condenser vacuum > 20".

(m) Including any reactor trip bypass breakers that are racked in and closed for bypassing an RTB.

Table 3.3.1-1 (Note 1)
Overtemperature ΔT

- NOTE -

The Overtemperature ΔT Function Limiting Safety System Setting is defined by:

$$\text{Overtemperature } \Delta T \leq \Delta T_0 \{K_1 + K_2 (P-P') - K_3 (T-T') [(1+\tau_1 s) / (1+\tau_2 s)] - f(\Delta I)\}$$

Where:

ΔT is measured RCS ΔT, °F.
ΔT_0 is the indicated ΔT at RTP, °F.

s is the Laplace transform operator, sec^{-1}.

T is the measured RCS average temperature, °F.
T' is the nominal T_{avg} at RTP, °F.

P is the measured pressurizer pressure, psig.
P' is the nominal RCS operating pressure, psig.

K_1 is the Overtemperature ΔT reactor trip setpoint, [*].
K_2 is the Overtemperature ΔT reactor trip depressurization setpoint penalty coefficient, [*]/psi.
K_3 is the Overtemperature ΔT reactor trip heatup setpoint penalty coefficient, [*]/°F.

τ_1 is the measured lead time constant, [*] seconds.
τ_2 is the measured lag time constant, [*] seconds.

$f(\Delta I)$ is a function of the indicated difference between the top and bottom detectors of the Power Range Neutron Flux channels where q_t and q_b are the percent power in the top and bottom halves of the core, respectively, and $q_t + q_b$ is the total THERMAL POWER in percent RTP.

$f(\Delta I) = 0$	when $q_t - q_b$ is $\leq$ [*]% RTP
$f(\Delta I) = [*] \{(q_t - q_b) - [*]\}$	when $q_t - q_b$ is > [*]% RTP

* These values denoted with [*] are specified in the COLR.

Table 3.3.1-1 (Note 2)
Overpower ΔT

- NOTE -

The Overpower ΔT Function Limiting Safety System Setting is defined by:

$$\text{Overpower } \Delta T \leq \Delta T_0 \{K_4 - K_5 (T-T') - K_6 [(\tau_3 sT) / (\tau_3 s+1)] - f(\Delta I)\}$$

Where:

ΔT is measured RCS ΔT, °F.
ΔT_0 is the indicated ΔT at RTP, °F.

s is the Laplace transform operator, sec^{-1}.

T is the measured RCS average temperature, °F.
T' is the nominal T_{avg} at RTP, °F.

K_4 is the Overpower ΔT reactor trip setpoint, [*].
K_5 is the Overpower ΔT reactor trip heatup setpoint penalty coefficient which is:
[*]/°F for T < T' and;
[*]/°F for T ≥ T'.
K_6 is the Overpower ΔT reactor trip thermal time delay setpoint penalty which is:
[*]/°F for increasing T and;
[*]/°F for decreasing T.

τ_3 is the measured impulse/lag time constant, [*] seconds.

$f(\Delta I)$ is a function of the indicated difference between the top and bottom detectors of the Power Range Neutron Flux channels where q_t and q_b are the percent power in the top and bottom halves of the core, respectively, and $q_t + q_b$ is the total THERMAL POWER in percent RTP.

$f(\Delta I)$ = [*]	when $q_t - q_b$ is ≤ [*]% RTP
$f(\Delta I)$ = [*] $\{(q_t - q_b)$ - [*]}	when $q_t - q_b$ is > [*]% RTP

* These values denoted with [*] are specified in the COLR.

3.3 INSTRUMENTATION

3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

LCO 3.3.2 The ESFAS instrumentation for each Function in Table 3.3.2-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2-1.

ACTIONS

- NOTE -

Separate Condition entry is allowed for each Function.

CONDITION		REQUIRED ACTION		COMPLETION TIME
A.	One or more Functions with one channel or train inoperable.	A.1	Enter the Condition referenced in Table 3.3.2-1 for the channel or train.	Immediately
B.	As required by Required Action A.1 and referenced by Table 3.3.2-1.	B.1	Restore channel to OPERABLE status.	48 hours
C.	Required Action and associated Completion Time of Condition B not met.	C.1	Be in MODE 2.	6 hours
D.	As required by Required Action A.1 and referenced by Table 3.3.2-1.	D.1	Restore channel to OPERABLE status.	48 hours
E.	As required by Required Action A.1 and referenced by Table 3.3.2-1.	E.1	Restore train to OPERABLE status.	6 hours

CONDITION		REQUIRED ACTION		COMPLETION TIME
F.	As required by Required Action A.1 and referenced by Table 3.3.2-1.	F.1	- NOTE - The inoperable channel may be bypassed for up to 4 hours for surveillance testing of the other channels. Place channel in trip.	6 hours
G.	Required Action and associated Completion Time of Condition D, E, or F not met.	G.1	Be in MODE 3.	6 hours
		<u>AND</u>		
		G.2	Be in MODE 4.	12 hours
H.	As required by Required Action A.1 and referenced by Table 3.3.2-1.	H.1	Restore channel to OPERABLE status.	48 hours
I.	As required by Required Action A.1 and referenced by Table 3.3.2-1.	I.1	Restore train to OPERABLE status.	6 hours
J.	As required by Required Action A.1 and referenced by Table 3.3.2-1.	J.1	- NOTE - The inoperable channel may be bypassed for up to 4 hours for surveillance testing of the other channels. Place channel in trip.	6 hours
K.	Required Action and associated Completion Time of Condition H, I, or J not met.	K.1	Be in MODE 3.	6 hours
		<u>AND</u>		
		K.2	Be in MODE 5.	36 hours

CONDITION	REQUIRED ACTION	COMPLETION TIME
L. As required by Required Action A.1 and referenced by Table 3.3.2-1.	L.1 ------------ - NOTE - The inoperable channel may be bypassed for up to 4 hours for surveillance testing of the other channels. ------------ Place channel in trip.	6 hours
M. Required Action and associated Completion Time of Condition L not met.	M.1 Be in MODE 3.	6 hours
	<u>AND</u>	
	M.2 Reduce pressurizer pressure to < 2000 psig.	12 hours
N. As required by Required Action A.1 and referenced by Table 3.3.2-1.	N.1 Declare associated Auxiliary Feedwater pump inoperable and enter applicable condition(s) of LCO 3.7.5, "Auxiliary Feedwater (AFW) System."	Immediately

SURVEILLANCE REQUIREMENTS

- NOTE -
Refer to Table 3.3.2-1 to determine which SRs apply for each ESFAS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.2.2	Perform COT.	92 days
SR 3.3.2.3	------------ - NOTE - Verification of relay setpoints not required. ------------ Perform TADOT.	92 days

	SURVEILLANCE	FREQUENCY
SR 3.3.2.4	- NOTE - Verification of relay setpoints not required. Perform TADOT.	 24 months
SR 3.3.2.5	Perform CHANNEL CALIBRATION.	24 months
SR 3.3.2.6	Verify the Pressurizer Pressure-Low and Steam Line Pressure-Low Functions are not bypassed when pressurizer pressure > 2000 psig.	24 months
SR 3.3.2.7	Perform ACTUATION LOGIC TEST.	24 months

Table 3.3.2-1
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	LIMITING SAFETY SYSTEM SETTINGS[a]
1. Safety Injection					
a. Manual Initiation	1,2,3,4	2	D,G	SR 3.3.2.4	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	I,K	SR 3.3.2.7	NA
c. Containment Pressure-High	1,2,3,4	3	J,K	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	≤ 4.61 psig
d. Pressurizer Pressure-Low	1,2,3[b]	3	L,M	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5 SR 3.3.2.6	≥ 1729.8 psig
e. Steam Line Pressure-Low	1,2,3[b]	3 per steam line	L,M	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5 SR 3.3.2.6	≥ 393.8 psig

Table 3.3.2-1
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	LIMITING SAFETY SYSTEM SETTINGS[a]
2. Containment Spray					
a. Manual Initiation					
Left pushbutton	1,2,3,4	1	H,K	SR 3.3.2.4	NA
Right pushbutton	1,2,3,4	1	H,K	SR 3.3.2.4	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	I,K	SR 3.3.2.7	NA
c. Containment Pressure-High High	1,2,3,4	3 per set	J,K	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	≤ 32.11 psig (narrow range) ≤ 29.6 psig (wide range)
3. Containment Isolation					
a. Manual Initiation	1,2,3,4,[c]	2	H,K	SR 3.3.2.4	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	I,K	SR 3.3.2.7	NA
c. Safety Injection	Refer to Function 1 (Safety Injection) for all automatic initiation functions and requirements.				

Table 3.3.2-1
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	LIMITING SAFETY SYSTEM SETTINGS[a]
4. Steam Line Isolation					
a. Manual Initiation	1,2[d],3[d]	1 per loop	D,G	SR 3.3.2.4	NA
b. Automatic Actuation Logic and Actuation Relays	1,2[d],3[d]	2 trains	E,G	SR 3.3.2.7	NA
c. Containment Pressure-High High	1,2[d],3[d]	3	F,G	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	≤ 18.0 psig
d. High Steam Flow	1,2[d],3[d]	2 per steam line	F,G	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	≤ 1.30E6 lbm/hr @ 1005 psig
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
and					
Coincident with T_{avg}-Low	1,2[d],3[d]	2 per loop	F,G	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	≥ 544.0°F
e. High-High Steam Flow	1,2[d],3[d]	2 per steam line	F,G	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	≤ 4.53E6 lbm/hr @ 785 psig
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				

Table 3.3.2-1
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	LIMITING SAFETY SYSTEM SETTINGS[a]
5. Feedwater Isolation					
a. Automatic Actuation Logic and Actuation Relays	1,2[e],3[e]	2 trains	E,G	SR 3.3.2.7	NA
b. SG Water Level-High	1,2[e],3[e]	3 per SG	F,G	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	≤ 91.15%
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				

Table 3.3.2-1
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	LIMITING SAFETY SYSTEM SETTINGS[a]
6. Auxiliary Feedwater (AFW)					
a. Manual Initiation					
AFW	1,2,3	1 per pump	N	SR 3.3.2.4	NA
Standby AFW	1,2,3	1 per pump	N	SR 3.3.2.4	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3	2 trains	E,G	SR 3.3.2.7	NA
c. SG Water Level-Low Low	1,2,3	3 per SG	F,G	SR 3.3.2.1 SR 3.3.2.2 SR 3.3.2.5	≥ 13.88%
d. Safety Injection (Motor driven pumps only)	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
e. Undervoltage - Bus 11A and 11B (Turbine driven pump only)	1,2,3	2 per bus	D,G	SR 3.3.2.3 SR 3.3.2.5	≥ 2597 V with ≤ 3.6 sec time delay
f. Trip of Both Main Feedwater Pumps (Motor driven pumps only)	1	2 per MFW pump	B,C	SR 3.3.2.4	NA

(a) A channel is OPERABLE when both of the following conditions are met:

1. The absolute difference between the as-found Trip Setpoint (TSP) and the previous as-left TSP is within the COT Acceptance Criteria. The COT Acceptance Criteria is defined as:

   |as-found TSP - previous as-left TSP| ≤ COT uncertainty

   The COT uncertainty shall not include the calibration tolerance.

2. The as-left TSP is within the established calibration tolerance band about the nominal TSP. The nominal TSP is the desired setting and shall not exceed the Limiting Safety System Setting (LSSS). The LSSS and the established calibration tolerance band are defined in accordance with the Ginna Instrument Setpoint Methodology. The channel is considered operable even if the as-left TSP is non-conservative with respect to the LSSS provided that the as-left TSP is within the established calibration tolerance band.

(b) Pressurizer Pressure ≥ 2000 psig.

(c) During CORE ALTERATIONS and movement of irradiated fuel assemblies within containment.

(d) Except when both MSIVs are closed and de-activated.

(e) Except when all Main Feedwater Regulating and associated bypass valves are closed and de-activated or isolated by a closed manual valve.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 Pressurizer Safety Valves

LCO 3.4.10 Two pressurizer safety valves shall be OPERABLE with lift settings $\geq$ 2410 psig and $\leq$ 2542 psig.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 with all RCS cold leg temperatures greater than the LTOP enable temperature specified in the PTLR.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One pressurizer safety valve inoperable.	A.1 Restore valve to OPERABLE status.	15 minutes
B. Required Action and associated Completion Time not met. OR Both pressurizer safety valves inoperable.	B.1 Be in MODE 3. AND B.2 Be in MODE 4 with any RCS cold leg temperature less than or equal to the LTOP enable temperature specified in the PTLR.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.10.1	- NOTE - Required to be performed within 36 hours of entering MODE 4 from MODE 5 with all RCS cold leg temperatures greater than the LTOP enable temperature specified in the PTLR for the purpose of setting the pressurizer safety valves under ambient (hot) conditions only provided a preliminary cold setting was made prior to heatup.	
	Verify each pressurizer safety valve is OPERABLE in accordance with the Inservice Testing Program. Following testing, lift settings shall be within ± 1%.	In accordance with the Inservice Testing Program

3.7 PLANT SYSTEMS

3.7.6 Condensate Storage Tanks (CSTs)

LCO 3.7.6 The CSTs shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. CST water volume not within limit.	A.1 Verify by administrative means OPERABILITY of backup water supply.	4 hours
	AND	
	A.2 Restore CST water volume to within limit.	7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.6.1	Verify the CST water volume is $\geq$ 24,350 gal.	12 hours

Attachment 4

R.E. Ginna Nuclear Power Plant

Proposed Technical Specification Bases Changes (markup)

The LCO requires three channels of the Pressurizer Water Level-High trip Function to be OPERABLE. The pressurizer level channels (LT-426, LT-427, and LT-428) are also used for other control functions. Section 7.2.5 of Reference 4 discusses control and protection system interactions for this function. The level channels do not actuate the safety valves, and the high pressure reactor trip is set below the safety valve setting. Therefore, with the slow rate of charging available, pressure overshoot due to level channel failure cannot cause the safety valve to lift before the reactor high pressure trip.

In MODE 1 or 2, when there is a potential for overfilling the pressurizer, the Pressurizer Water Level-High trip Function must be OPERABLE. In MODES 3, 4, 5, or 6, the Pressurizer Water Level-High trip Function is not required to be OPERABLE because transients that could raise the pressurizer water level will be slow and the operator will have sufficient time to evaluate plant conditions and take corrective actions.

9. Reactor Coolant Flow-Low

The Reactor Coolant Flow-Low (Single Loop) and (Two Loops) trip Functions utilize three common flow transmitters per RCS loop to generate a reactor trip above approximately 8% RTP (P-7 setpoint). Flow transmitters FT-411, FT-412, and FT-413 are used for RCS Loop A and FT-414, FT-415, and FT-416 are used for RCS Loop B.

a. Reactor Coolant Flow-Low (Single Loop)

The Reactor Coolant Flow-Low (Single Loop) trip Function ensures that protection is provided against violating the DNBR limit due to low flow in the RCS loop, while avoiding reactor trips due to normal variations in loop flow. Above the
25 P-8 setpoint, (approximately 49% RTP), a loss of flow in either RCS loop will actuate a reactor trip. Each RCS loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

The LCO requires three Reactor Coolant Flow-Low (Single Loop) trip Function channels per RCS loop to be OPERABLE
30 in MODE 1 ≥ 50% RTP (above P-8 setpoint). Each loop is considered a separate Function for the purpose of this LCO.

In MODE 1 above the P-8 setpoint, a loss of flow in one RCS loop could result in DNB conditions in the core. In MODE 1 below the P-8 setpoint the Reactor Coolant Flow-Low (Single Loop) trip Function is not required to be OPERABLE because a loss of flow in one loop has been evaluated and found to be acceptable (Ref. 6).

b. Reactor Coolant Flow-Low (Two Loops)

The Reactor Coolant Flow-Low (Two Loops) trip Function ensures that protection is provided against violating the DNBR limit due to low flow in both RCS loops while avoiding reactor trips due to normal variations in loop flow.

The LCO requires three Reactor Coolant Flow-Low (Two Loops) trip Function channels per loop to be OPERABLE in MODE 1 above 8.5% RTP (above the P-7 setpoint) and before the Reactor Coolant Flow-Low (Single Loop) trip Function is OPERABLE (below the P-8 setpoint). Each loop is considered a separate Function for the purpose of this LCO.

Above the P-7 setpoint and below the P-8 setpoint, a loss of flow in both loops will initiate a reactor trip. Each loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

Below the P-7 setpoint, this trip Function is not required to be OPERABLE because all reactor trips on low flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on low flow in both RCS loops is automatically enabled. Above the P-8 setpoint, the Reactor Coolant Flow-Low (Two Loops) trip Function is not required to be OPERABLE because loss of flow in any one loop will actuate a reactor trip because of the higher power level and the reduced margin to the design limit DNBR.

10. RCP Breaker Position

Both RCP Breaker Position trip Functions (Single Loop and Two Loops) utilize a common auxiliary contact located on each RCP. These Functions anticipate the Reactor Coolant Flow-Low trips to avoid RCS heatup that would occur before the low flow trip actuates but are not specifically credited in the accident analysis.

a. Reactor Coolant Pump Breaker Position (Single Loop)

The RCP Breaker Position (Single Loop) trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in one RCS loop. The position of each RCP breaker is monitored. If one RCP breaker is open above approximately 49% RTP, a reactor trip is initiated. This trip Function will generate a reactor trip before the Reactor Coolant Flow-Low (Single Loop) Trip Setpoint is reached.

25

The LCO requires one RCP Breaker Position trip Function 30 channel per RCP to be OPERABLE in MODE 1 ≥ 50% RTP (above the P-8 setpoint). Each RCP is considered a separate Function for the purpose of this LCO. One OPERABLE channel is sufficient for this trip Function because the RCS Flow-Low trip alone provides sufficient protection of plant SLs for loss of flow events. The RCP Breaker Position trip serves only to anticipate the low flow trip, minimizing the thermal transient associated with loss of a pump.

This Function measures only the discrete position (open or closed) of the RCP breaker, using a position switch. Therefore, the Function has no adjustable trip setpoint with which to associate an LSSS.

In MODE 1 above the P-8 setpoint, when a loss of flow in any RCS loop could result in DNB conditions in the core, the RCP Breaker Position (Single Loop) trip Function must be OPERABLE. In MODE 1 below the P-8 setpoint, the RCP Breaker Position (Single Loop) trip Function is not required to be OPERABLE because a loss of flow in one loop has been evaluated and found to be acceptable (Ref. 6).

b. <u>RCP Breaker Position (Two Loops)</u>

The RCP Breaker Position (Two Loops) trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in both RCS loops. The position of each RCP breaker is monitored. If both RCP breakers are open above approximately 8% RTP (P-7 setpoint) and before the RCP Breaker Position (Single Loop) trip Function is OPERABLE (below the P-8 setpoint), a reactor trip is initiated. This trip Function will generate a reactor trip before the Reactor Coolant Flow-Low (Two Loops) Trip Setpoint is reached.

The LCO requires one RCP Breaker Position trip Function channel per RCP to be OPERABLE in MODE 1 above the P-7 and below the P-8 setpoints. Each RCP is considered a separate Function for the purpose of this LCO. One OPERABLE channel is sufficient for this Function because the RCS Flow-Low trip alone provides sufficient protection of plant SLs for loss of flow events. The RCP Breaker Position trip serves only to anticipate the low flow trip, minimizing the thermal transient associated with loss of an RCP.

This Function measures only the discrete position (open or closed) of the RCP breaker, using a position switch. Therefore, the Function has no adjustable trip setpoint with which to associate an LSSS.

c. Power Range Neutron Flux, P-8 Permissive

25 The Power Range Neutron Flux, P-8, permissive is actuated at approximately 40% power as determined by two-out-of-four NIS power range detectors. The P-8 interlock allows the Reactor Coolant Flow-Low (Single Loop) and RCP Breaker Position (Single Loop) reactor trips on low flow in one or more RCS loops to be blocked so that a loss of a single loop will not cause a reactor trip. The LCO requirement for this trip Functions ensures that protection is provided against a loss of flow in any RCS loop that could result in DNB conditions in the core when ≥50% power. 30

The LCO requires four channels of Power Range Neutron Flux, P-8 interlock to be OPERABLE in MODE 1 ≥50% RTP. 30

In MODE 1, a loss of flow in one RCS loop could result in DNB conditions, so the Power Range Neutron Flux, P-8 permissive must be OPERABLE. In MODE 1 <50% RTP, this function is not required to be OPERABLE because a loss of flow in one loop will not result in DNB. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the core is not producing sufficient power to be concerned about DNB conditions. 30

d. Power Range Neutron Flux, P-9 Permissive

The Power Range Neutron Flux, P-9 permissive is actuated at approximately 50% power as determined by two-out-of-four NIS power range detectors if the Steam Dump System is available and at approximately 8% if the Steam Dump System is unavailable. The LCO requirement for this Function ensures that the Turbine Trip-Low Autostop Oil Pressure and Turbine Trip-Turbine Stop Valve Closure reactor trips are enabled above the P-9 setpoint. Above the P-9 setpoint, a turbine trip will cause a load rejection beyond the capacity of the Steam Dump System and RCS. A reactor trip is automatically initiated on a turbine trip when it is above the P-9 setpoint, to minimize the transient on the reactor.

The LCO require four channels of Power Range Neutron Flux, P-9 permissive to be OPERABLE in MODE 1 above the permissive setpoint.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 4 hours while performing surveillance testing of the other channels. The 4 hours is applied to each of the two OPERABLE channels. The 4 hour time limit is consistent with Reference 9.

N.1

Condition N applies to the RCP Breaker Position (Single Loop) trip Function. Condition N applies on a per loop basis. There is one breaker position device per RCP breaker. With one channel per RCP inoperable, the inoperable channel must be restored to OPERABLE status within 6 hours. The 6 hours allowed to restore the channel to OPERABLE status is consistent with Reference 9.

O.1

30

If the Required Action and associated Completion Time of Condition M or N is not met, the plant must be placed in a MODE where the Functions are not required to be OPERABLE. To achieve this status, THERMAL POWER must be reduced to < 50% RTP within the next 6 hours. The Completion Time of 6 hours is consistent with Reference 9.

P.1

Condition P applies to Turbine Trip on Low Autostop Oil Pressure or on Turbine Stop Valve Closure in MODE 1 above the P-9 setpoint. With one channel inoperable, the inoperable channel must be restored to OPERABLE status or placed in the tripped condition within 6 hours. If placed in the tripped Condition, this results in a partial trip condition requiring only one additional channel to initiate a reactor trip. The 6 hours allowed to place the inoperable channel in the tripped condition is consistent with Reference 9.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 4 hours while performing surveillance testing of the other channels. The 4 hours is applied to each remaining OPERABLE channel. The 4 hour time limit is consistent with Reference 9.

Q.1, Q.2.1, and Q.2.2

If the Required Action and Associated Completion Time of Condition P are not met, the plant must be placed in a MODE where the Turbine Trip Functions are no longer required to be OPERABLE. To achieve this status, THERMAL POWER must be reduced to < 50% RTP within the next 6 hours. The Completion Time of 6 hours is consistent with Reference 9.

c. Steam Line Isolation-Containment Pressure-High High

This Function actuates closure of both MSIVs in the event of a LOCA or an SLB inside containment to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment. The transmitters are located outside containment with the sensing lines passing through containment penetrations to sense the containment atmosphere in three different locations. Thus, they will not experience any adverse environmental conditions, and the Trip Setpoint reflects only steady state instrument uncertainties. Containment Pressure-High High provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with two-out-of-three logic. PT-946, PT-948, and PT-950 are the three channels required for this function. The loss of inverter MQ-483 requires declaring PT-950 inoperable.

Containment Pressure-High High must be OPERABLE in MODES 1, 2, and 3, because there is sufficient energy in the primary and secondary side to pressurize the containment following a pipe break. This would cause a significant increase in the containment pressure, thus allowing detection and closure of the MSIVs. The steam line isolation Function must be OPERABLE in MODES 2 and 3 unless both MSIVs are closed and de-activated. In MODES 4, 5, and 6 the steam line isolation Function is not required to be OPERABLE because there is not enough energy in the primary and secondary sides to pressurize the containment to the Containment Pressure-High High setpoint.

d. Steam Line Isolation-High Steam Flow Coincident With Safety Injection and Coincident With T_{avg}-Low

This Function provides closure of the MSIVs during an SLB or inadvertent opening of multiple SG atmospheric relief or safety valves to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment.

LSSS

The specified ~~Allowable Value~~ is based on steam line breaks occurring from no load conditions (1005 psig). Specifically, steam line breaks which result in a ~~≥ 10% RTP step change (0.66E6 lbm/hr)~~ are considered. The steam flow signal to this function's bistables are not pressure compensated (i.e., only the main control board indicators are compensated). However, the high steam flow bistable setpoint is determined from the expected flow transmitter differential pressure under steam conditions of ~~0.66~~ E6 lbm/hr at 1005 psig. Steam

steam flow analytical limit of > 1.50E6 lbm/hr

1.50

< 1.50E6 lbm/hr do not require automatic action to isolate.

breaks which result in higher flowrates or lower pressure generate larger differential pressures such that the high steam flow bistables would be tripped. Steam line breaks which result in ~~a ≤ 10% RTP step change can be manually isolated by operators.~~ The high steam flow bistables are OPERABLE if they are placed in the tripped condition since the specified Limiting Safety System Setting (LSSS) are met. However, all applicable surveillances related to the tripped channel must continue to be performed and met.

Two steam line flow channels per steam line are required to be OPERABLE for this Function. These are combined in a one-out-of-two logic to indicate high steam flow in one steam line. FT-464 and FT-465 are the two channels required for steam line A. FT-474 and FT-475 are the two channels required for steam line B. Each steam line is considered a separate function for the purpose of this LCO. The steam flow transmitters provide control inputs, but the control function cannot initiate events that the function acts to mitigate. Therefore, additional channels are not required to address control protection interaction issues. The one-out-of-two configuration allows online testing because trip of one high steam flow channel is not sufficient to cause initiation.

The main steam line isolates only if the high steam flow signal occurs coincident with an SI and low RCS average temperature. The Main Steam Line Isolation Function requirements for the SI Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all applicable initiating functions and requirements.

Two channels of T_{avg} per loop are required to be OPERABLE for this Function. TC-401 and TC-402 are the two channels required for RCS loop A. TC-403 and TC-404 are the two channels required for RCS loop B. Each loop is considered a separate Function for the purpose of this LCO. The T_{avg} channels are combined in a logic such that any two of the four T_{avg} channels tripped in conjunction with SI and one of the two high steam line flow channels tripped causes isolation of the steam line associated with the tripped steam line flow channels. The accidents that this Function protects against cause reduction of T_{avg} in the entire primary system. Therefore, the provision of two OPERABLE channels per loop in a two-out-of-four configuration ensures no single failure disables the T_{avg}-Low Function. The T_{avg} channels provide control inputs, but the control function cannot initiate events that the Function acts to mitigate. Therefore, additional channels are not required to address control protection interaction issues.

This Function must be OPERABLE in MODES 1, 2, and 3 when a secondary side break or stuck open valve could result in rapid depressurization of the steam lines. The Steam Line Isolation Function is required to be OPERABLE in MODES 2 and 3 unless both MSIVs are closed and de-activated. This Function is not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the plant to have an accident.

e. Steam Line Isolation-High High Steam Flow Coincident With Safety Injection

This Function provides closure of the MSIVs during a large steam line break to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment.

analytical limit

LSSS

The specified ~~Allowable Value~~ is based on steamline breaks occurring from full power steam conditions which result in ≥ ~~400~~ 155 % RTP steam flow. The steam flow signal to this function's bistables are not pressure compensated (i.e., only the main control board indicators are compensated). However, the high-high steam flow bistable setpoint is determined from the expected flow transmitter differential pressure under steam conditions of ~~3.7~~ <1.53 E6 lbm/hr at ~~755~~ 785 psig. Steam breaks which result in higher flowrates or lower pressure generate larger differential pressures such that the high-high steam flow bistables would be tripped.

Two steam line flow channels per steam line are required to be OPERABLE for this Function. These are combined in a one-out-of-two logic to indicate high-high steam flow in one steam line. FT-464 and FT-465 are the two channels required for steam line A. FT-474 and FT-475 are the two channels required for steam line B. Each steam line is considered a separate function for the purpose of this LCO. The steam flow transmitters provide control inputs, but the control function cannot initiate events that the Function acts to mitigate. Therefore, additional channels are not required to address control protection interaction issues.

The main steam lines isolate only if the high-high steam flow signal occurs coincident with an SI signal. Steamline isolation occurs only for the steam line associated with the tripped steam flow channels. The Main Steam Line Isolation Function requirements for the SI Functions are the same as the requirements for their SI function. Therefore, the

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LCO

The two pressurizer safety valves are set to open at the RCS design pressure (2500 psia), and within the ASME specified tolerance, to avoid exceeding the maximum design pressure SL, to maintain accident analyses assumptions, and to comply with ASME requirements. The upper and lower pressure tolerance limits following testing are based on the ± 1% tolerance requirements (Ref. 1) for lifting pressures above 1000 psig. The OPERABILITY limits of +2.4%, - 3% are based on the analyzed events. The limit protected by this Specification is the reactor coolant pressure boundary (RCPB) SL of 110% of design pressure for all transients except locked rotor accidents which has an allowed limit of 120% of design pressure. Inoperability of one or more valves could result in exceeding the SL if a transient were to occur. The consequences of exceeding the ASME pressure limit could include damage to one or more RCS components, increased leakage, or additional stress analysis being required prior to resumption of reactor operation.

2.3

APPLICABILITY

In MODES 1, 2, and 3, and portions of MODE 4 above the LTOP arming temperature, OPERABILITY of two valves is required because the combined capacity is required to keep reactor coolant pressure below 110% of its design value during certain accidents. MODE 3 and portions of MODE 4 are conservatively included, although the listed accidents may not require the safety valves for protection.

The LCO is not applicable in MODE 4 when either RCS cold leg temperature is less than or equal to the LTOP enable temperature specified in the PTLR or in MODE 5 because LTOP is provided. Overpressure protection is not required in MODE 6 with the reactor vessel head detensioned or the SG primary system manway or the pressurizer manway open.

ACTIONS

A.1

With one pressurizer safety valve inoperable, restoration must take place within 15 minutes. The Completion Time of 15 minutes reflects the importance of maintaining the RCS Overpressure Protection System. An inoperable safety valve coincident with an RCS overpressure event could challenge the integrity of the pressure boundary.

B.1 and B.2

If the Required Action of A.1 cannot be met within the required Completion Time or if both pressurizer safety valves are inoperable, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 with either RCS cold leg temperature less than or equal to the LTOP enable temperature specified in the PTLR within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. With any RCS cold leg temperature at or below the LTOP enable temperature specified in the PTLR, overpressure protection is provided by the LTOP System. The change from MODE 1, 2, or 3 to MODE 4 reduces the RCS energy (core power and pressure), lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection by both pressurizer safety valves.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SRs are specified in the Inservice Testing Program. Pressurizer safety valves are to be tested in accordance with the requirements of Section XI of the ASME Code (Ref. 7), which provides the activities and Frequencies necessary to satisfy the SRs. No additional requirements are specified.

2.3

The pressurizer safety valve setpoint is + ~~2.4~~%, - 3% for OPERABILITY; however, the valves are reset to ± 1% during the surveillance to allow for drift.

This SR is modified by a Note that allows entry into MODES 3 and 4 without having performed the SR for the purpose of setting the pressurizer safety valves under ambient (hot) conditions. This permits testing and examination of the safety valves at high pressure and temperature near their normal operating range, but only after the valves have had a preliminary cold setting. The cold setting gives assurance that the valves are OPERABLE near their design condition until completion of the surveillance.

A nonlimiting event considered in CST inventory determinations is a main feedwater line break inside containment. This break has the potential for dumping condensate until terminated by operator ACTION after 10 minutes since there is no automatic re-configuration of the AFW System. Following termination of the AFW flow to the affected SG by closing the AFW train discharge valves or stopping a pump, flow from the remaining AFW train or the SAFW System is directed to the intact SG for decay heat removal. This loss of condensate is partially compensated for by the retention of inventory in the intact SG.

For cooldowns following loss of all onsite and offsite AC electrical power, the CSTs contain sufficient inventory to provide a minimum of 2 hours of decay heat removal via the turbine-driven AFW pump >as required by NUREG-0737 (Ref. 4), item II.E.1.1. This beyond DBA requirement provides more limiting criteria for CST inventory.

The CSTs satisfy Criterion 3 of the NRC Policy Statement.

LCO

To satisfy accident analysis assumptions, the CST must contain sufficient inventory to support operation of the preferred AFW system for at least 10 minutes. After this time period, the accident analyses assume that AFW pump suction can be transferred to the safety related suction source (i.e., the SW System).

24,350

24,350

24,350

However, the required CST water volume is ≥ ~~22,500~~ gallons, which is based on the need to provide at least 2 hours of decay heat removal via the turbine-driven AFW pump following loss of all AC electrical power (i.e., a beyond design basis event). The CSTs are considered OPERABLE when at least ~~22,500~~ gallons of water is available. The ~~22,500~~ gal minimum volume is met if one CST is ≥ ~~21.5 ft~~ or if both CSTs are ≥ ~~12.5 ft~~. Since the CSTs are 30,000 gallon tanks, only one CST is required to meet the minimum required water volume for this LCO.

21.4 ft (not including instrument uncertainty)

11.5 ft (not including instrument uncertainty)

The OPERABILITY of the CSTs is determined by maintaining the tank level at or above the minimum required water volume.

APPLICABILITY

In MODES 1, 2, and 3, the CSTs are required to be OPERABLE to support the AFW System requirements.

In MODE 4, 5, or 6, the CST is not required because the AFW System is not required to be OPERABLE.

ACTIONS

A.1 and A.2

If the CST water volume is not within limits, the OPERABILITY of the backup supply should be verified by administrative means within 4 hours. OPERABILITY of the backup feedwater supply must include verification that the flow paths from the backup water supply to the preferred AFW pumps are OPERABLE and immediately available upon AFW initiation, and that the backup supply has the required volume of water available. Alternate sources of water include, but is not limited to, the SW System and the all-volatile-treatment condensate tank. In addition, the CSTs must be restored to OPERABLE status within 7 days, because the backup supply may be performing this function in addition to its normal functions. Continued verification of the backup supply is not required due to the large volume of water typically available from these alternate sources. The 7 day Completion Time is reasonable, based on an OPERABLE backup water supply being available, and the low probability of an event occurring during this time period requiring the CSTs.

B.1 and B.2

If the backup supply cannot be verified or the CSTs cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

21.4 ft (not including instrument uncertainty)

24,350

This SR verifies that the CSTs contain the required volume of cooling water. The ~~22,500~~ gal minimum volume is met if one CST is ≥ ~~21.5~~ ft or if both CSTs are ≥ ~~12.5~~ ft. The 12 hour Frequency is based on operating experience and the need for operator awareness of plant evolutions that may affect the CST inventory between checks. Also, the 12 hour Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator to abnormal deviations in the CST level.

11.5 ft (not including instrument uncertainty

Attachment 6

R.E. Ginna Nuclear Power Plant

Westinghouse Authorization Letter, CAW-05-2014,
with Accompanying Affidavit, Proprietary Information Notice, and Copyright Notice

Westinghouse

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Our ref: CAW-05-2014

July 7, 2005

APPLICATION FOR WITHHOLDING PROPRIETARY INFORMATION FROM PUBLIC DISCLOSURE

Subject: WCAP-16461-P, "Ginna Station Extended Power Uprate Supplemental Information" (Proprietary)

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-05-2014 signed by the owner of the proprietary information, Westinghouse Electric Company LLC. The affidavit, which accompanies this letter, sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR Section 2.390 of the Commission's regulations.

Accordingly, this letter authorizes the utilization of the accompanying affidavit by Ginna Nuclear Power Plant, LLC.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse affidavit should reference this letter, CAW-05-2014, and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Very truly yours,

J. A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Enclosures

cc: B. Benney
L. Feizollahi

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF ALLEGHENY:

Before me, the undersigned authority, personally appeared J. A. Gresham, who, being by me duly sworn according to law, deposes and says that he is authorized to execute this Affidavit on behalf of Westinghouse Electric Company LLC (Westinghouse), and that the averments of fact set forth in this Affidavit are true and correct to the best of his knowledge, information, and belief:

PATRICIA L. CROWN
COMMONWEALTH OF PENNSYLVANIA
NOTARY PUBLIC

J. A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Sworn to and subscribed
before me this 7th day
of July, 2005

Patricia L. Crown
Notary Public

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Patricia L. Crown, Notary Public
Monroeville Boro, Allegheny County
My Commission Expires Feb. 7, 2009
Member, Pennsylvania Association of Notaries

(1) I am Manager, Regulatory Compliance and Plant Licensing, in Nuclear Services, Westinghouse Electric Company LLC (Westinghouse), and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rule making proceedings, and am authorized to apply for its withholding on behalf of Westinghouse.

(2) I am making this Affidavit in conformance with the provisions of 10 CFR Section 2.390 of the Commission's regulations and in conjunction with the Westinghouse "Application for Withholding" accompanying this Affidavit.

(3) I have personal knowledge of the criteria and procedures utilized by Westinghouse in designating information as a trade secret, privileged or as confidential commercial or financial information.

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.390 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse.

(ii) The information is of a type customarily held in confidence by Westinghouse and not customarily disclosed to the public. Westinghouse has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence. The application of that system and the substance of that system constitutes Westinghouse policy and provides the rational basis required.

Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage, e.g., by optimization or improved marketability.

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

There are sound policy reasons behind the Westinghouse system which include the following:

(a) The use of such information by Westinghouse gives Westinghouse a competitive advantage over its competitors. It is, therefore, withheld from disclosure to protect the Westinghouse competitive position.

(b) It is information that is marketable in many ways. The extent to which such information is available to competitors diminishes the Westinghouse ability to sell products and services involving the use of the information.

(c) Use by our competitor would put Westinghouse at a competitive disadvantage by reducing his expenditure of resources at our expense.

(d) Each component of proprietary information pertinent to a particular competitive advantage is potentially as valuable as the total competitive advantage. If competitors acquire components of proprietary information, any one component may be the key to the entire puzzle, thereby depriving Westinghouse of a competitive advantage.

(e) Unrestricted disclosure would jeopardize the position of prominence of Westinghouse in the world market, and thereby give a market advantage to the competition of those countries.

(f) The Westinghouse capacity to invest corporate assets in research and development depends upon the success in obtaining and maintaining a competitive advantage.

(iii) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.390, it is to be received in confidence by the Commission.

(iv) The information sought to be protected is not available in public sources or available information has not been previously employed in the same original manner or method to the best of our knowledge and belief.

(v) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in WCAP-16461-P, "Ginna Station Extended Power Uprate Supplemental Information" (Proprietary), dated July 2005, being transmitted by the Ginna Nuclear Power Plant, LLC letter and Application for Withholding Proprietary Information from Public Disclosure, to the Document Control Desk. The proprietary information as submitted by Westinghouse for the Ginna Station Extended Power Uprate is expected to be applicable for other licensee submittals in response to certain NRC requirements for justification of power plant uprating.

This information is part of that which will enable Westinghouse to:

(a) Provide information in support of plant power uprate licensing submittals.

(b) Provide plant specific calculations.

(c) Provide licensing documentation support for customer submittals.

Further this information has substantial commercial value as follows:

(a) Westinghouse plans to sell the use of similar information to its customers for purposes of meeting NRC requirements for licensing documentation associated with power uprate licensing submittals

(b) Westinghouse can sell support and defense of the technology to its customers in the licensing process.

(c) The information requested to be withheld reveals the distinguishing aspects of a methodology which was developed by Westinghouse.

Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar calculations, evaluations, analysis, and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

The development of the technology described in part by the information is the result of applying the results of many years of experience in an intensive Westinghouse effort and the expenditure of a considerable sum of money.

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort, having the requisite talent and experience, would have to be expended.

Further the deponent sayeth not.

PROPRIETARY INFORMATION NOTICE

Transmitted herewith are proprietary and/or non-proprietary versions of documents furnished to the NRC in connection with requests for generic and/or plant-specific review and approval.

In order to conform to the requirements of 10 CFR 2.390 of the Commission's regulations concerning the protection of proprietary information so submitted to the NRC, the information which is proprietary in the proprietary versions is contained within brackets, and where the proprietary information has been deleted in the non-proprietary versions, only the brackets remain (the information that was contained within the brackets in the proprietary versions having been deleted). The justification for claiming the information so designated as proprietary is indicated in both versions by means of lower case letters (a) through (f) located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (4)(ii)(a) through (4)(ii)(f) of the affidavit accompanying this transmittal pursuant to 10 CFR 2.390(b)(1).

Attachment 8

R.E. Ginna Nuclear Power Plant

Supplemental Environmental Report

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Acronyms and Abbreviations

°F	degrees Fahrenheit
ΔT	change in temperature
AEC	Atomic Energy Commission
ALARA	as low as reasonably achievable
CFR	Code of Federal Regulations
CWS	circulating cooling water system
DAW	dry active waste
EPU	extended power uprate
FES	Final Environmental Statement
FR	Federal Register
GEIS	Generic Environmental Impact Statement for the License Renewal of Nuclear Power Plants
Ginna LLC	R.E. Ginna Nuclear Power Plant, LLC
Ginna Station	R.E. Ginna Nuclear Power Plant
kV	kilovolt
LLRW	low-level radioactive waste
MGD	million gallons per day
mrem	millirem
msl	mean sea level
MWd/MTU	megawatt-days per metric tons uranium
MWe	megawatt electric
MWt	megawatt thermal
NEPA	National Environmental Policy Act
NRC	U.S. Nuclear Regulatory Commission
NYSDEC	New York State Department of Environmental Conservation
PILOT	Payment In-Lieu of Taxes Agreement
RIS	Representative Important Fish Species
SPDES	State Pollution Discharge Elimination System
SW	service water system
UFSAR	Updated Final Safety Analysis Report

1.0 Executive Summary

This Supplemental Environmental Report contains R.E. Ginna Nuclear Power Plant, LLC's (Ginna LLC's) assessment of the environmental impacts of the proposed R.E. Ginna Nuclear Power Plant (Ginna Station) extended power uprate (EPU) from 1,520 megawatts-thermal (MWt) to 1,775 MWt. The intent is to provide sufficient information for the U.S. Nuclear Regulatory Commission (NRC) to evaluate the environmental impact of the power uprate in accordance with the requirements of 10 CFR 51.

The environmental impacts of the proposed EPU are described and compared to those previously identified by the U.S. Atomic Energy Commission in the 1973 *Final Environmental Statement for the Operation of the R.E. Ginna Nuclear Plant* and the NRC's Supplement 14 of the *Generic Environmental Impact Statement for the License Renewal of Nuclear Power Plants* (NUREG-1437) issued in 2004 to address the license renewal of Ginna Station. The comparisons show that the conclusions of the Final Environmental Statement (FES) and NUREG-1437, Supplement 14 remain valid for operation at 1,775 MWt.

The Ginna Station EPU would be implemented without making extensive changes to plant systems that directly or indirectly interface with the environment. All necessary modifications would be in existing buildings at Ginna Station; none would involve land disturbance or new construction outside of the established facility areas. There would be no change in the amount of water withdrawn from Lake Ontario for condenser cooling, and an approximate 17 percent increase in the amount of waste heat discharge to Lake Ontario. Generation of low-level radioactive waste would not increase significantly over the current generation rate, and would be bounded by FES values. There would be no change in the volume of radioactive effluents (liquid and gaseous) released to the environment; however, the radioactive content of the liquid and gaseous releases would be proportional to the size of the power uprate which is bounded by the FES analysis. All offsite radiation doses would remain small and within applicable standards. There would be no impact on the size of the regular workforce.

Ginna LLC evaluated the compliance requirements associated with implementing the proposed EPU. Ginna LLC will maintain compliance with New York State permits, licenses, approvals or other requirements currently held by the Plant. The New York State Pollutant Discharge Elimination System permit would require modification to accommodate the increase in heat rejected from the condensers, and a Water Quality Certification from the State would also be required. Ginna LLC will submit a request for these approvals and certifications concurrent with submittal of the EPU license amendment request to NRC.

Ginna LLC concludes that the environmental impacts of operation at 1,775 MWt are either bounded by the impacts described in earlier National Environmental Policy Act assessments or constrained by applicable regulatory criteria. As a result, Ginna LLC believes that the EPU would not significantly affect human health or the environment.

2.0 Introduction

R.E. Ginna Nuclear Power Plant, LLC (Ginna LLC) is committed to operating R.E. Ginna Nuclear Power Plant (Ginna Station) in an environmentally responsible manner. Plant activities including design, construction, maintenance, and operations are conducted in a manner so as to protect the environment and responsibly manage natural resources. Ginna LLC believes proper care of the environment is essential to the well-being of our corporation, its employees, its neighbors, and the broader global community. Ginna Station has operated for more than 35 years in compliance with state and federal environmental regulations, while providing safe, reliable, and economical electrical power to its customers in New York.

In keeping with this commitment to environmental stewardship and in accordance with regulatory requirements, Ginna LLC has conducted a thorough environmental evaluation of the proposed extended power uprate (EPU) of Ginna Station from 1,520 megawatts thermal (MWt) to 1,775 MWt. This would increase electrical output to 580 megawatts-electric (MWe). The proposed uprate would serve the future power requirements of the State of New York and the region.

This environmental evaluation is provided pursuant to 10 CFR 51.41 ("Regulations to Submit Environmental Information") and is intended to support the U.S. Nuclear Regulatory Commission (NRC) environmental review of the proposed uprate. The proposed EPU would require the issuance of an operating license amendment. The regulation (10 CFR 51.41) requires that applications to the NRC be in compliance with Section 102(2) of the National Environmental Policy Act (NEPA) and consistent with the procedural provisions of NEPA (40 CFR 1500-1508). There are no NRC regulatory requirements or guidance documents specific to preparation of environmental reports for EPUs.

In March 1973, the U.S. Atomic Energy Commission (AEC; predecessor agency to NRC) published the *Final Environmental Statement Related to the Operation of the R.E. Ginna Nuclear Power Plant Unit 1* (FES; AEC 1973). The AEC concluded that the issuance of the full-term operating license, subject to certain conditions related to monitoring, was the appropriate course of action under NEPA. This decision was based on the analysis presented in the FES and the weight of environmental, economic, and technical information reviewed by the AEC. It also took into consideration the environmental costs and economic benefits of operating Ginna Station. The AEC subsequently issued the operating license to Ginna Station that authorized operation up to the maximum power level of 1,520 MWt.

In February 2004, NRC published Supplement 14 of the *Generic Environmental Impact Statement for the License Renewal of Nuclear Power Plants* that addressed the license renewal of Ginna Station (NRC 2004). NRC determined that the adverse environmental impacts of license renewal (i.e., operating an additional 20 years) are not so great that preserving the option of license renewal for energy-planning decisionmakers would be unreasonable. The decision was based upon the analysis presented in NUREG-1437, *Generic Environmental Impact Statement for the Renewal of Nuclear Power Plants* (GEIS; NRC 1996) and NUREG-1437, Supplement 14.

General information about the design and operational features of Ginna Station that are of interest from an environmental impact standpoint is available in several documents. In addition to the FES and Supplement 14 of the GEIS discussed above, another comprehensive source of information is the Updated Final Safety Analysis Report (UFSAR; Ginna 2004a), prepared and maintained by Ginna LLC.

This Supplemental Environmental Report is intended to provide sufficient detail on both the radiological and non-radiological environmental impacts of the proposed EPU to allow NRC to make an informed decision regarding the proposed action. It does not reassess the current environmental licensing basis or justify the environmental impacts of operating at the current licensed power level of 1,520 MWt. Rather, this document demonstrates that the effects of operating under EPU conditions are bounded by the original analyses documented in the FES, the more recent Supplement 14 of the GEIS, or by current regulatory limits.

3.0 Proposed Action and Need

The Ginna Station site is in the town of Ontario, in the northwest corner of Wayne County, New York, on the south shore of Lake Ontario. The Plant is situated on approximately 426 acres that include the powerblock area and ancillary facilities. Figures 3-1, 3-2, and 3-3 show the site location and site map.

Ginna Station is a single-unit plant that uses a pressurized water reactor and a nuclear steam supply system designed by Westinghouse. Ginna LLC operates Ginna Station pursuant to NRC Operating License DPR-18, which will expire September 18, 2029. Ginna Station received a provisional operating license on September 19, 1969, a full-term operating license on December 10, 1984, and an extended license on May 19, 2004.

3.1 Proposed Action

The proposed action is to increase the licensed core thermal level of the Ginna Station unit from 1,520 MWt to 1,775 MWt, which represents an increase of approximately 17 percent. This change in core thermal level would require the NRC to amend the facility's operating license. The operational goal of the proposed EPU is a corresponding (approximately 17 percent) increase in electrical output, from 495 to 580 MWe. The proposed action is considered an extended power uprate by NRC because it exceeds the typical 7 percent power increase that can be accommodated with only minor plant changes. EPUs are expected to involve significant plant modifications.

Ginna LLC intends to increase the power in a single phase during the Fall 2006 Refueling Outage, though startup testing will be performed at intermediate power levels. This Supplemental Environmental Report evaluates environmental impacts associated with increasing thermal power to 1,775 MWt.

3.2 Need for Action

The proposed action provides Ginna LLC with the flexibility to increase the potential electrical output of Ginna Station and to supply low cost, reliable, and efficient electrical generation to New York State and the region. The additional 85 MWe would be enough to power approximately 95,000 homes. The State of New York forecasted an average annual growth rate of 1.3 percent in electricity and peak demand for the period of 2004 through 2013 and estimates that approximately 5,400 MW of additional resources would be needed by 2020 to maintain the 18 percent reserve margin requirement for this period (NYSEPB 2002 and 2005). Reserve margin is defined as the ratio of required excess generation capacity to projected peak load demand. The proposed EPU at Ginna Station would contribute to meeting the goals and recommendations of the New York State Energy Plan for maintaining the reserve margin and reducing greenhouse gas emissions with low cost, efficient, and reliable electrical generation.

The cost of adding the generating capacity associated with the proposed EPU at Ginna Station is roughly equivalent to the cost of constructing two small (50-MWe) combustion turbine units. However, nuclear power generation costs (including the costs of fuel, operations, and maintenance) are approximately one-fifth those of natural gas-powered generation. A comparison to production costs of natural gas is made because as noted in the New York State Energy Plan, almost all of the new generation proposed to be built in the state is to be fired by natural gas (NYSEPB 2002). The proposed EPU would provide increased capacity at a lower production cost than natural gas or other fossil fuel alternatives.

Figure 3-1
50-Mile Region

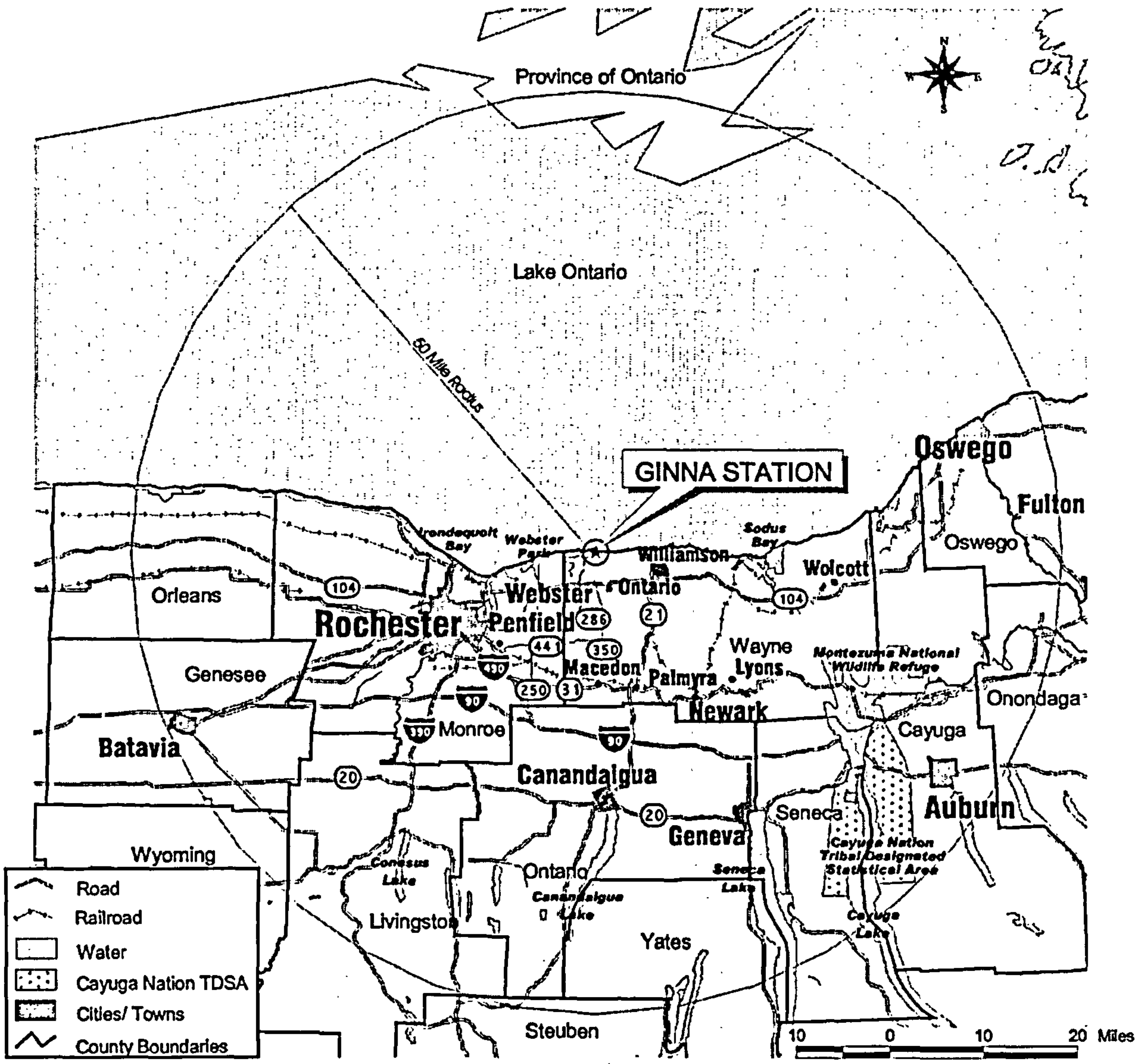


Figure 3-2
6-Mile Region

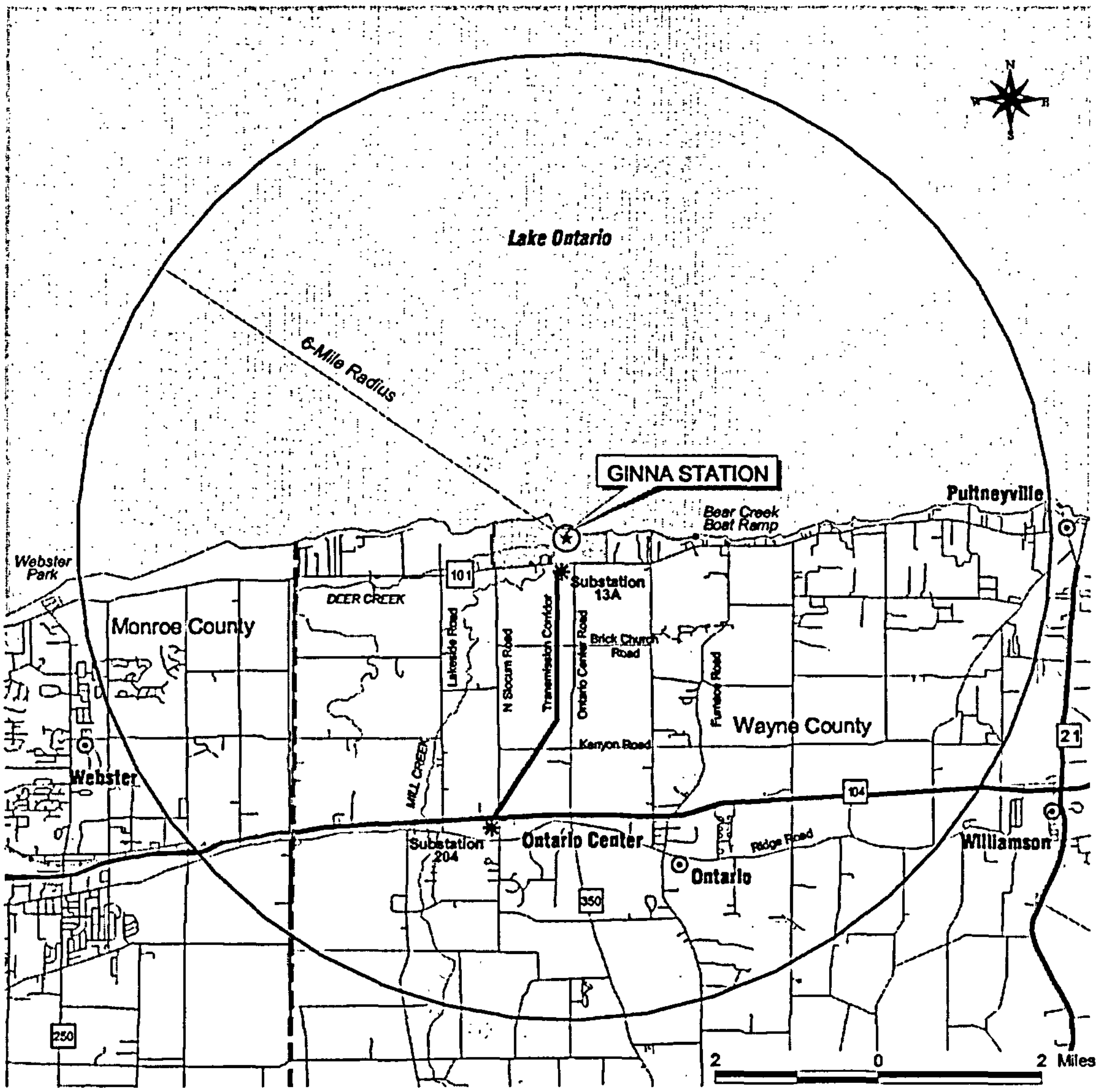
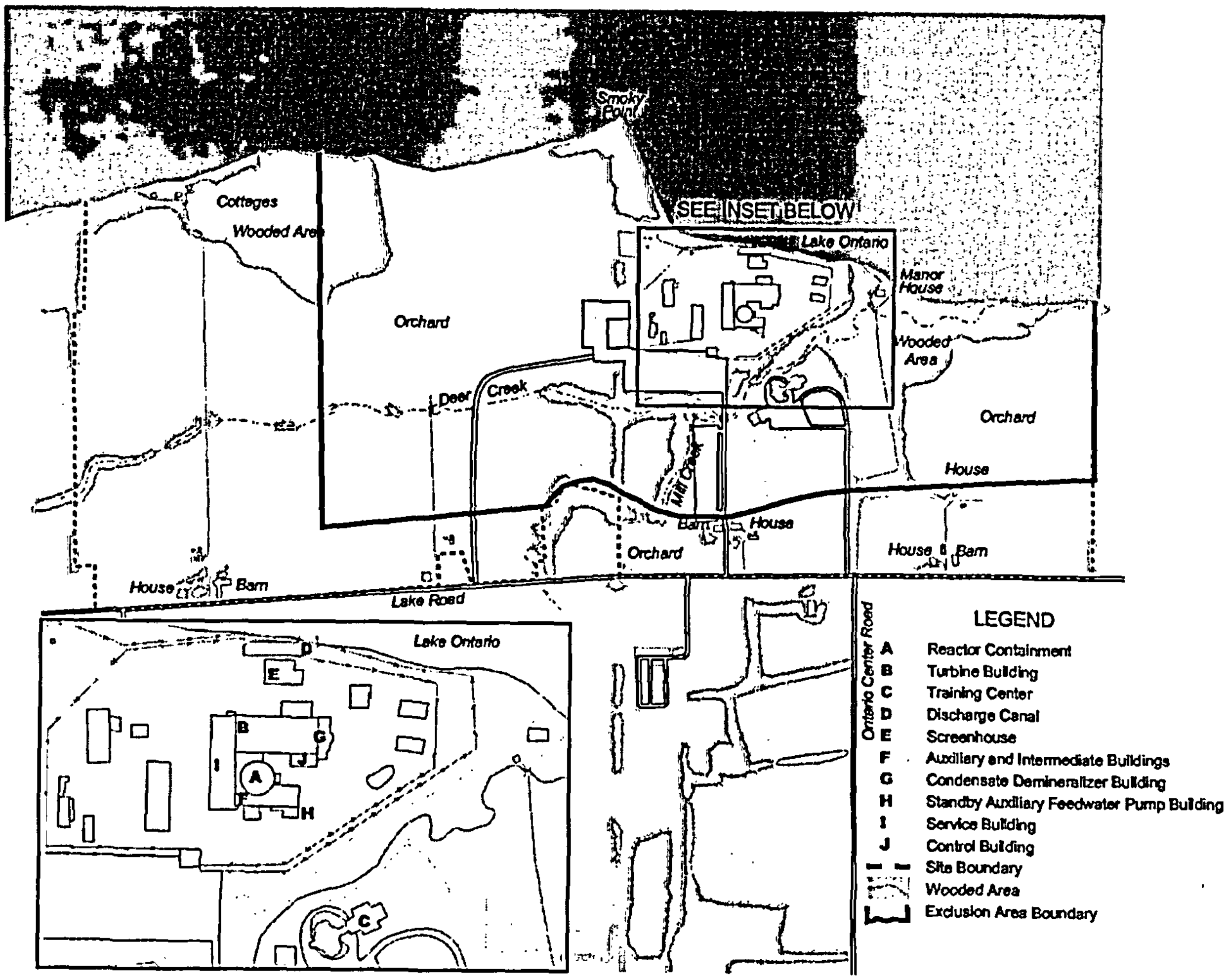


Figure 3-3
Site Map



4.0 Overview of Operational and Equipment Changes

In general, light water reactors are designed with an as-built equipment capability to increase power up to 7 percent above the original licensed power level. For power uprates beyond this level, more extensive plant modifications are generally required to increase capability. Table 4.1 lists the modifications needed to implement the proposed EPU at Ginna Station. Ginna LLC recognizes the following three major modifications that have been completed in the last 10 years provide the opportunity to increase power at Ginna Station with minimal additional modifications of the reactor and plant safety systems.

- Re-tubing the main condenser (1995)
- Replacing the steam generators with an oversized design (1996)
- Replacing the reactor vessel head (2003)

With exception of the high-pressure turbine rotor, the required modifications are generally of relatively small scope. The required modifications listed in Table 4-1 will be accomplished in two refueling outages, the Spring 2005 Refueling Outage and the Fall 2006 Refueling Outage, prior to the proposed power escalation. Ginna LLC completed many of the modifications listed during the March 2005 Refueling Outage to take advantage of scheduled regular maintenance on the main generator. With the exception of the fast-acting actuator on the main feedwater isolation valves, all of the modifications may be implemented without prior NRC review under 10 CFR 50.59. 10 CFR 50.59 establishes the criteria and record requirements for plant changes, test, and experiments that do not require NRC approval. Therefore, implementation of most of the EPU modifications will proceed in parallel with the NRC review of the EPU license amendment request.

The activities needed to produce thermal power increases are a combination of those that directly produce more power and those that will accommodate the effects of the power increase. The primary means of producing more power are a change in the fuel design, an operational change in reactor thermal-hydraulic parameters, and upgrade of the balance of plant capacity by component replacement or modification. Other changes include replacing the high-pressure turbine, replacing selected feedwater and condensate motors that are already operating at capacity, providing additional cooling for some plant systems, various electrical upgrades to accommodate the higher currents and to improve electrical stability, modifications to accommodate greater steam and condensate flow rates, and instrumentation upgrades that include replacing parts, changing setpoints and modifying software.

Table 4-1
Equipment Modifications to Support the Ginna Station Extended Power Uprate

Spring 2005 Refueling Outage	Fall 2006 Refueling Outage
Main Generator monitoring instrumentation modification	High-pressure turbine and turbine control valves replacement
Condensate booster pump (1) and motor (3) replacement	Fast acting feedwater isolation valve operator installation
New fuel handling equipment installation	First region of upgraded fuel assemblies
Main transformer bushing replacement and cooler modification	Main feedwater pump impellers/motors replacement
Exciter coupling keyway modification	Main feedwater regulating valves
	Condensate booster pump (2) replacement
	Main steam relief safety valves replacement
	Drain and vent piping and valves replacement
	Generator condensate cooler replacement
	Iso-phase bus duct cooling modifications
	Oilstatic cable monitoring instrumentation
	Various main steam supports replacement
	Generator protection and voltage regulator setting changes
	Various instrument replacements
	Standby auxiliary feedwater valve modification
	Condensate storage tank overfill line modification
	Oilstatic cable differential current protection relay modification
	Water solid cooldown spool pieces
	Containment cooler fan motor or cable shielding
	Control rod position indication modification
	Turbine driven auxiliary feedwater pump valve local controller
	Charging pump control power disconnect switch
	Charging pump backup air tank installation
	'B' steam generator level instrument modification
	Main turbine gland sealing steam spillover modification

5.0 Socioeconomic Considerations

The proposed EPU at Ginna Station would provide economic benefits to the surrounding communities through the continuation of tax revenues, local business revenues funded by EPU installation and continued operation, and continued employment of the local population.

5.1 Current Socioeconomic Status

Ginna Station currently employs approximately 436 people on a full-time basis and 167 long- and short-term contractors on a regular basis. This workforce is augmented by an additional 534 persons on average during regularly scheduled refueling outages. Activities to complete the EPU modifications scheduled for the 2006 Refueling Outage will require a somewhat larger outage workforce. Employment at Ginna Station benefits local and regional economies as employee salaries flow through the communities purchasing good and services and contributing income, sales, and personal property taxes. In addition, property taxes paid by Ginna LLC as the owner of Ginna Station are significant. Ginna LLC purchased the plant in June 2004, and has in place a Payment In-Lieu of Taxes Agreement (PILOT) with the Town of Ontario, the Wayne Central School District, and Wayne County. The terms of the agreement went into effect on January 1, 2005 and remain in effect through the 2015 tax year. Under this agreement, Ginna Station's assessed value has been set at $260,000,000. Annual payments in-lieu of taxes will be paid to the tax jurisdictions in an amount equal to the assessed value multiplied by the real property tax rate established by the respective tax jurisdictions for the applicable tax year. Tax payment information including the amount paid in 2004 and estimates of what will be paid through 2009 are displayed in Table 5-1. Communities in the vicinity of Ginna Station will continue to benefit from property taxes paid to the local taxing jurisdictions. Public services such as public education, police and fire protection, roads maintenance, and other municipal services are funded in part through property tax revenues.

Table 5-1
Taxes Paid by Ginna LLC for Ginna Station for Tax Years 2004-2009

Tax Year	Property Tax Paid [a,b] ($)
2004	5,900,000
2005	8,500,000
2006	9,100,000
2007	9,200,200
2008	9,400,000
2009	9,400,000

a. Year 2004 includes taxes paid by Rochester Gas & Electric Corp. prior to Ginna LLC assuming ownership in June 2004.

b. Year 2005 through 2009 payments are based on Ginna LLC's estimate of the tax rates that will be in effect for those respective years.

5.2 Extended Power Uprate Impacts to Socioeconomics

The proposed EPU is not anticipated to affect the size of the regular workforce. Workforce numbers for the 2006 outage, when EPU modifications will be completed, will be somewhat larger than previous outages, but would be of short duration and of such a magnitude as to not adversely affect housing availability, transportation services, or public utilities such as public water supply systems in the plant vicinity. Employee incomes and the purchases of goods and services afforded by those incomes along with the personal property taxes paid would continue to contribute positively to the communities in the vicinity of Ginna Station. Increasing Ginna Station's licensed power level would not affect the assessed value of the plant under the PILOT agreement that is in effect through 2015. The property tax payments made under the terms of the PILOT would continue to represent substantial contributions to the budgets of the taxing jurisdictions. Payments made to engineering and consulting firms, equipment suppliers, and service industries for implementation of the proposed EPU would have a positive, though unsustained impact on local and regional economies. Additionally, there would be the economic benefit to both the regional and local economies of the enhanced viability of Ginna Station's long-term operation resulting from the additional electrical generation.

5.3 Conclusion

The socioeconomic impacts of implementing the proposed EPU at Ginna Station include the positive contribution to the local and regional economies of payments for goods and services associated with the proposed action. Additionally, the continuation of employment of the local population with the associated expenditures for goods and services and contributions to income, sales, and property taxes along with the continuation of property tax payments by Ginna LLC for Ginna Station would both positively impact local and regional economies.

6.0 Cost – Benefit Analysis

The largest direct benefit resulting from the proposed EPU to Ginna Station's current capacity is the additional supply of more than 85 megawatts of reliable electrical power for residential and commercial customers. A national comparison of power-producing alternatives indicates that nuclear power generation production costs are approximately 85 percent of coal-fired power, and 27 percent of oil-fired power, and 19 percent of natural gas-fired power production. Power production costs represent a combination of fuel, operations, and maintenance costs.

A quantitative evaluation of environmental costs of alternatives would not be necessary to recognize that significant environmental impacts would be avoided by implementing an EPU at Ginna Station versus other options for additional capacity. Unlike fossil fuel plants, an EPU would not result in significant source of nitrogen oxides, carbon dioxide, or other atmospheric pollutants during normal operations. Routine operation of Ginna Station at EPU conditions would not contribute to greenhouse gases or acid rain. The radiological effects of the uranium fuel cycle are described in 10 CFR 51.51 and 51.52 and are classified as small. The tables in 10 CFR 51.52 bound that associated with the Ginna Station EPU. While the proposed action would produce additional spent nuclear fuel, the additional amount would represent less than a 5-percent increase in the number of spent fuel assemblies generated over of the remaining life of the plant and would be accommodated by Ginna Station's current spent fuel storage strategy.

Based upon these considerations, it is reasonable to conclude the proposed Ginna Station EPU would provide an economic advantage over other generation alternatives. The proposed EPU involves a cost-effective utilization of an existing asset, with relatively minor environmental impact, making it the preferred means of securing additional generating capacity.

7.0 Non-Radiological Environmental Impacts

7.1 Terrestrial Impacts

7.1.1 Land Use

The proposed EPU for Ginna Station would not affect land use at the 426-acre site. The current site acreage is less than that reported in NUREG-1437, Supplement 14 (488 acres) due to the fact that the land associated with Substation 13A was not included in the purchase of the plant from Rochester Gas & Electric in 2004. No new construction is planned outside of existing facilities and no expansion of buildings, roads, parking lots, equipment storage areas, or transmission facilities would be required to support the proposed EPU. The proposed EPU is not expected to involve substantial additional volumes of industrial chemicals, fuels, or lubricants, and as a result, would not require additional space for above- or below-ground storage tanks.

As discussed in Section 5.2, the proposed EPU would not affect the size of the workforce at Ginna Station. Because no land disturbance would be required and because there would be no expansion of the existing workforce, impacts to aesthetic resources and historical/archeological resources would be negligible. The conclusions of the FES and NUREG-1437, Supplement 14 with respect to land use, aesthetics, and historical/archeological resources remain valid for the proposed EPU.

7.1.2 Transmission Facilities

The proposed EPU would not require any new transmission lines and would not require changes in the maintenance and operation of existing transmission lines, switchyards, or substations. Right-of-way maintenance practices including vegetation management would not be affected by the proposed EPU. The only change to transmission facilities would be an increase in current. Voltage would be unchanged.

The proposed EPU would not increase the probability of shock from primary or secondary currents. The increase in electrical power output would cause a corresponding current rise on the transmission system. However, the increase is within the design margin of the lines. As noted in NUREG-1437, Supplement 14, the four 115-kV transmission lines at Ginna Station are below the size of concern for induced shock and field measurements demonstrate the electric-field-induced currents from these transmission lines are well below the NESC recommendations for preventing shock from induced currents (NRC 2004).

The increase in electrical power output would cause a corresponding current rise on the transmission system, and this would result in an increased magnetic field. Ginna LLC adopts by reference the NRC conclusion that chronic effects of EMF on humans are not quantified at this time and no significant impacts to terrestrial biota have been identified (NRC 1996).

7.1.3 Miscellaneous Waste

Ginna LLC reviewed a number of plant systems and associated (non-radiological) discharges for potential effects from the proposed EPU. Chemical discharge limits for primary and secondary outfall systems such as roof drains, yard drains, low volume waste, and metal cleaning waste are set in the Ginna Station State Pollutant Discharge Elimination System

(SPDES) permit. Discharges from these systems are not expected to change under the proposed EPU conditions; therefore, the impact on the environment would not change. Nonradiological parameters affected by the proposed EPU would remain within the bounding conditions established in the SPDES permit, and as a consequence no significant impacts would result from the operations of Ginna Station under proposed EPU conditions.

7.1.4 Noise

The proposed EPU would not produce measurable changes in the character, sources, or intensity of noises generated at Ginna Station. New equipment necessary to implement the proposed EPU would be installed within existing buildings at Ginna Station. No significant increase in ambient noise levels is expected inside or outside the plant.

7.1.5 Terrestrial Biota

The Ginna Station site can be characterized by habitat types typical of Central and Western New York State. These consist of mature woodlands, meadows, and early- and late-stage old fields. These areas are not presently being actively managed by Ginna LLC and are undergoing natural succession. In addition, significant acreage is farmed for grains or is in use as apple orchards. The Station property that is farmed is leased to local residents. The FES (AEC 1973) contains detailed descriptions of these plant communities and the animals that are typically associated with them. As noted in NUREG-1437, Supplement 14, these descriptions remain representative for these communities. There are no state or federally regulated wetlands occurring at the Ginna Station site.

Two state-listed protected species, the endangered peregrine falcon (*Falco peregrinus*) and the threatened species northern harrier (*Circus cyaneus*), use the shoreline during spring migration. Bald eagles (*Haliaeetus leucocephalus*), which are listed as federally threatened, are also known to use the shoreline during spring migration. However, there is no habitat at the Ginna Station site that is considered to be a critical habitat for these or any other protected species. There are no known occurrences of other state- or federally listed terrestrial species on or in the vicinity of the Ginna Station site. As the proposed action would not involve any land disturbance, increases in noise levels outside the plant, or increases in the Ginna Station workforce, there would be no significant impacts to terrestrial biota, including state- or federally-listed protected species.

7.2 Aquatic Impacts

7.2.1 Lake Ontario

Lake Ontario is the smallest of the Great Lakes and measures approximately 190 miles long by 50 miles wide. It has a surface area of 7,340 square miles. The maximum depth is 802 feet. Its mean depth, 283 feet, is greater than that of the other Great Lakes, except Superior, and it is the eleventh largest lake in the world in volume. The mean surface elevation of Lake Ontario is about 246 feet above mean sea level (msl). Depths of 40 to 100 feet occur within one to two miles off the southern shoreline in the vicinity of the Ginna Station. The major source of water, approximately 86 percent, to Lake Ontario is the outflow from Lake Erie via the Niagara River, located about 90 miles to the west of Ginna Station. The outflow from Lake Ontario is via the St. Lawrence River, about 60 miles east of Ginna Station, to the Atlantic Ocean. The predominant surface currents along Lake Ontario's southern shoreline are from west to east, and they tend to swing toward the south shore. This water movement would be expected due to the effect of prevailing winds and the Earth's rotation.

The lake bottom off the Ginna Station is characterized by the presence of exposed bedrock in the form of a series of shelves with the long axis lying east-west. While this lake bottom has a fairly even overall slope of about 1:100, numerous irregularities are found scattered throughout this area, such as hollows three to four feet in depth, or areas of mixed boulder and cobble. These irregularities provide potential areas of inhabitation and refuge for fish and invertebrates.

In the near shore area, the overburden is predominantly smaller cobble and rubble, with the size of the material gradually increasing with depth into boulder-sized rocks. Further lakeward there is a general tendency for the flat bedrock to be exposed. Frequently, a thin layer of fine sediment will cover the bottom substrates. Stable beds of cobble or boulders, and areas of exposed bedrock, are substrates that provide good habitat for the growth of *Cladophora*, which is the principal periphyton of the Lake and grows profusely in the area. Historically, *Cladophora* growth was generally limited to lake depths of 20 feet or less, due to poor water clarity and associated light limitations. With increased water clarity in recent years, however, *Cladophora* growth at depths up to 30 feet have been reported.

To the west of the Plant, Smoky Point juts out into the Lake for about 1,000 feet. The strong long-shore current carries suspended material around the tip of Smoky Point, where it gradually settles out as a long, tongue-shaped area extending eastward for almost 5,000 feet. This area of deposition lies at a depth of between 10 to 15 feet and curves shoreward beginning about 1,000 feet east of the point and then stretches eastward. The shoreline of Lake Ontario, within the Ginna Station protected area, is covered by a revetment composed of large stones and is designed to provide surge flooding protection.

The FES and NUREG-1437, Supplement 14 provide a detailed characterization of the Lake Ontario fisheries and the changes experienced by this ecosystem. A number of other factors—such as the salmonid stocking program, the introduction of non-native invasive aquatic species, on-going anthropogenic impacts, and natural climatic variabilities—have been major contributors to substantially altering the water quality and ecological communities within Lake Ontario over the past 25 to 30 years. The synergy of these factors has caused the state of relatively reduced productivity that currently exists in the Lake.

The Lake Ontario offshore pelagic community is dominated by alewife (*Alosa pseudoharengus*), smelt (*Osmerus m. mordax*), and the salmonids that prey on them. In recent years the extreme predatory pressure from the salmonids, reduced food supply due to reduced zooplankton populations, and susceptibility to cold winters have reduced the alewife population. The invasion of the exotic species *Driessena* spp. (zebra and quagga mussels), have further impacted the ecosystem. Driessenids are filter feeders, gaining nourishment from phytoplankton in the water column and coagulating and depositing other water-borne detrital material on the lake bottom in the form of pseudofeces. With driessenid numbers of greater than 20,000 per square meter often found on the bottom of the Lake, and filtering rates of 1 to 2 liters per day per mussel, the impact of these species on water clarity and phytoplankton numbers is not insignificant. With the removal of organic material from the water column and deposition on the lake bottom, there is a transfer of production from the pelagic to the benthic communities; however, the driessenid impacts on the benthic community are not yet understood (Haynes et al. 1999).

Other exotic species have recently invaded Lake Ontario, though none are credited with having impacts comparable to driessenids. These include the relatively large zooplankters *Cercopagis pengoi* and *Bythrotrephes cederstroemi*, commonly called the fish hook water flea and spiny water flea, respectively. While their ecological impacts may not be currently defined, the fish hook water flea has gained a reputation as a nuisance due to its tendency to clump and foul fishing lines. At Ginna Station, it has occasionally been found within various strainers of the circulating cooling water system, but has not posed any particular operational problems. At the fishery level, the round goby (*Neogobius melonostomus*) has been reported on occasion within Lake Ontario (Hoyle et al. 2001), and it has been collected in Ginna Station impingement sampling in 2003, 2004, and 2005 (Ginna 2005a). This species is known to have rapid population growth in new areas and has shown the ability to out-compete native fish for food and habitat (Jude 1997).

The primary data set available to provide insight on this and the current fishery status is that of the Ginna Station Impingement Program (Ginna 2004b, 2005a, RGE 2002a). The Ginna Station Impingement Program has been conducted weekly throughout each year since its inception in 1973. The primary purpose of this program is to monitor the fishery community in the area of the Lake near Ginna Station. The Ginna Station Impingement Program's nearly 30-year monitoring data record is one of the longest consistent fishery databases on the Great Lakes. A list of aquatic species impinged at Ginna Station over the past five years is presented in Table 7-1. Regarding abundance, the Ginna Station data show relatively high numbers impinged during the mid-1970s (reflecting the large populations of alewife and smelt in the Lake at that time) followed by an overall continual decline in numbers over the years to the present (Ginna 2004b, 2005a).

Ichthyoplankton (fish eggs and larvae) studies, conducted at the Ginna Station site in 1977 and 1978, characterize the site with respect to utilization of the Lake Ontario shoreline adjacent to the Ginna Station site for fish spawning and as a nursery area (BSR 1978, 1979). More than 90 percent of the fish larvae found during both years were alewives. Also found both years, in the 1 percent to 5 percent range, were carp/goldfish (*Cyprinus carpio/Carrassius aurtus*), smelt, and johnny darters (*Etheostoma nigrum*).

Table 7-1
Species Collected During R.E. Ginna Nuclear Plant Annual Impingement Studies, 2000 - 2004

Genus	Species	Common Name	2000	2002	2001	2003	2004
Anguilla	*rostrata*	American Eel	X	X	X	X	
Moxostoma	*erythrurum*	Golden Redhorse				X	
Moxostoma	*macrolepidotum*	Shorthead Redhorse					X
Catostomus	*commersoni*	White Sucker	X	X	X	X	X
Ambloplites	*rupestris*	Rock Bass	X	X	X	X	X
Lepomis	*gibbosus*	Pumpkinseed	X		X	X	X
Lepomis	*macrochirus*	Bluegill	X	X	X	X	X
Lepomis	*sp.*	Unidentified Sunfish			X		
Micropterus	*dolomieu*	Smallmouth Bass	X	X	X	X	X
Micropterus	*salmoides*	Largemouth Bass			X	X	X
Alosa	*pseudoharengus*	Alewife	X	X	X	X	X
Dorosoma	*cepedianum*	Gizzard Shad	X	X	X	X	X
Cottus	*spp.*	Sculpin	X	X	X	X	X
Carassius	*auratus*	Goldfish		X			
Couesius	*plumbeus*	Lake Chub	X	X	X	X	X
Notropis	*atherinoides*	Emerald Shiner	X	X	X	X	X
Notropis	*heterodon*	Blackchin Shiner					X
Notropis	*hudsonius*	Spottail Shiner	X	X	X	X	X
Pimephales	*promelas*	Fathead Minnow		X			
Rhinichthys	*cataractae*	Longnose Dace		X			X
Fundulus	*diaphanus*	Banded Killifish				X	
Lota	*iota*	Burbot		X	X	X	
Culaea	*inconstans*	Brook Stickleback				X	X
Gasterosteus	*aculeatus*	Threespine Stickleback	X	X	X	X	X
Neogobius	*melanostomus*	Round Goby				X	X
Ameiurus	*nebulosus*	Brown Bullhead			X	X	
Noturus	*flavus*	Stonecat	X	X	X	X	X
Lepisosteus	*osseus*	Longnose Gar			X		
Osmerus	*mordax*	Rainbow Smelt	X	X	X	X	X
Morone	*chrysops*	White Bass	X	X	X	X	
Morone	*americana*	White Perch	X	X	X	X	X

Table 7-1 (continued)
Species Collected During R.E. Ginna Nuclear Plant
Annual Impingement Studies, 2000 - 2004

Genus	Species	Common Name	2000	2002	2001	2003	2004
Etheostoma	*flabellare*	Fantail Darter		X			X
Etheostoma	*nigrum*	Johnny Darter		X			X
Etheostoma	*olmstedi*	Tessellated Darter	X	X	X	X	X
Perca	*flavescens*	Yellow Perch	X	X	X	X	X
Percina	*caprodes*	Logperch					X
Stizostedion	*vitreum*	Walleye		X	X	X	X
Percopsis	*omiscomaycus*	Trout Perch	X		X	X	X
Petromyzon	*marinus*	Sea Lamprey		X	X	X	X
Oncorhynchus	*tshawytscha*	Chinook Salmon				X	X
Oncorhynchus	*kisutch*	Coho Salmon		X	X	X	
Oncorhynchus	*mykiss*	Rainbow Trout	X	X		X	
Salmo	*salar*	Atlantic Salmon	X				
Salmo	*trutta*	Brown Trout	X	X	X	X	X
Salvelinus	*namaycush*	Lake Trout	X	X	X	X	X
Aplodinotus	*grunniens*	Freshwater Drum			X	X	X
Umbra	*limi*	Central Mudminnow			X	X	

Source: Ginna 2005a.

Entrainment sampling was conducted at Ginna Station in 2004 per SPDES Permit requirements. The study resulted in the collection and identification of three fish taxa in a variety of life history stages and in relatively low abundance. Alewife was the most abundant species accounting for 97.25 percent of the total fish catch. Smallmouth bass (*Micropterus dolomieui*) and threespine stickleback (*Gasterosteus aculeatus*) accounted for the remaining 2.75 percent of the fish collected. The 2004 entrainment sample analysis also resulted in the identification of six species of zooplankton. The fishhook water flea was the most abundant species accounting for 55 percent of the total zooplankton collection. *Holopedium gibberum* and *Daphnia retrocurva* combined accounted for 40 percent of the zooplankton collected. The last 5 percent included species such as *Dipoeria hoyi*, *Limnocalanus macrurus*, *Bryozoa*, *Hydracarina sp.*, and zooplankton individuals unidentified due to physical disfigurement (Ginna 2005b).

All of these species are common components of the local fish community, and typical of the fish communities found along the nearshore areas of Lake Ontario's southern shoreline. Studies conducted within Lake Ontario near Chaumont, Sodus, and Irondequoit Bays, during 1997 and 1998, show that alewife continues to dominate the ichthyoplankton population and that alewife spawning locations are ubiquitous (Klumb et al. undated).

7.2.2 Ginna Station Cooling Water Systems

Circulating Water System (CWS): Ginna Station utilizes a once-through condenser cooling system with a submerged offshore intake and a surface shoreline discharge. The total nominal flow of water circulating through the turbine condenser and service water systems is about 354,600 gallons per minute (gpm). A flow of approximately 340,000 gpm is used in the turbine condenser system and the rest is available for use in the service water system and fire protection systems. The CWS system is a completely separate system from the closed-cycle secondary cooling system. The CWS also contains a condensate cooler that is used to cool condensate to the hydrogen coolers and air ejectors.

The function of the CWS is to provide a reliable supply of water to condense the steam exhausted from the low-pressure turbines. The water source and heat sink for the circulating water system is Lake Ontario. The CWS functions to remove heat from the steam cycle via the main condensers and is designed to do so regardless of weather or Lake conditions. The system consists of an offshore intake structure designed specifically to minimize the possibility of clogging, an intake tunnel, four traveling screens, two circulating water pumps, and shoreline discharge via a short discharge canal.

The intake structure is located 3,100 feet out from shore at a depth of about 33 feet of water at mean lake level, 244.7 feet msl. In order to meet the high reliability requirements, the intake is completely submerged below the surface of the Lake. Even an occurrence of historical low water level will result in no less than 15 feet of water covering the intake structure. From the intake, a 10-foot diameter reinforced concrete-lined tunnel slopes downward over its 3,100-foot length for a total elevation decrease of 10 feet. From underneath the screenhouse, the tunnel rises vertically and connects to a reinforced-concrete inlet plenum, or forebay, in the screenhouse. Warm water recirculation from the discharge canal is provided in the screenhouse inlet forebay, when intake water temperature is below 45°F (winter operating mode). Recirculation of the heated discharge is used to maintain the inlet water temperature within an approximate range of 43-45°F, which optimizes condenser efficiency and melts any ice that might reach or form at this point.

Before the cooling water reaches the two circulating water pumps that send it through the condensers, the water passes through one of four parallel traveling screens. The four originally installed traveling screens are now fitted with 3/16-inch by 1-inch rectangular, stainless steel crimped-fit mesh, and are similar in concept to vertical conveyor belts. The screens, which remove fish and debris from the cooling water system, are operated sequentially, each being washed for 15-20 minutes. There is at least one traveling screen in operation at all times when at least one of the circulating cooling water pumps is operating. The screens can operate at two speeds, slow and fast, and in two modes, automatic and manual. Service water is typically used to flush the debris off the screens into a 1.3-foot wide and up to 2.0-foot deep concrete trough, or screen washwater discharge fish/debris sluice. It runs from the four traveling screens to the discharge canal and has four turns, all greater than 145° and more than 17 feet apart. Currently, water travels through the sluice at a flow rate of 40 gallons per minute while the screens are in operation. All fish and debris, excluding collections during the impingement studies, are returned to Lake Ontario via this sluice.

Water leaves the condensers and discharges into two condenser discharge tunnels, which are each 8-feet wide and 7-feet high and are rectangular in shape. They run west 95 feet and then north towards the discharge canal. Just north of the Turbine Building the two tunnels direct flow into two 96-inch pre-stressed reinforced-concrete pipes. These two pipes run 160 feet and enter the discharge canal at the bottom of a seal well. The purpose of a seal well is to provide a water seal and prevent air from entering the condensers via the discharge lines. The floor rises gradually from the seal well (231.5 feet msl) to an elevation of 238 feet msl. This elevation is maintained throughout the rest of the canal. The discharge canal is on the north side of the screen house and is 40-feet wide. The canal is rectangular and is constructed of reinforced concrete. At a lake elevation of 246 feet msl, the discharge canal has an average water depth of 8 feet and the discharge flow velocity is 2.34 feet per second. The canal has a recirculation weir that can direct warm discharge water into the screenhouse inlet forebay. The canal then turns north and extends another 35 feet, where it enters Lake Ontario at the shoreline. This last 35 feet is lined with armour stones. The discharge canal is protected from large debris by a submarine net placed inside the canal near the shoreline. The fish/debris sluice enters the discharge canal near its centerline, about 100 feet from the point where the canal outfalls to the Lake. Discharge velocity in the canal at the sluice discharge ranges from 2-5 feet per second.

Service Water (SW) System: The SW system consists of four service water pumps located in the screen house. They are two-stage, vertical turbine pumps (specified rating of 5,300 gpm). The SW circulates Lake Ontario water from the screenhouse to various heat exchangers and systems inside the containment and the auxiliary, intermediate, turbine, and diesel generator buildings. The SW system supplies cooling water to various turbine, as well as auxiliary reactor, plant loads. It provides multiple water source flow paths to ensure the availability of the ultimate heat sink. Typically, three SW pumps run during the summer months, and during the winter months two pumps are in operation.

Treated Water System: The treated water system comprises the following secondary plant subsystems: demineralized water production; domestic (potable) water; secondary water chemical treatment; and non-radioactive liquid waste disposal (floor drains, secondary sample effluents, etc.). The treated water subsystems are non-safety related auxiliary systems that support the functionality of other process systems. The principal components of the treated water system are pumps, tanks, ion exchange vessels, and the essential piping, hoses, and valves necessary for the subsystems to function. Domestic-quality water, at a flow of about 287,000 gallons per day, purchased from the Ontario Water District, Town of Ontario provides the source water for these systems. An underground retention tank is the collection point for the various building floor and equipment drains, and provides retention of these effluents for sampling and treatment prior to discharging into the circulating water discharge. All sanitary waste from Ginna Station is discharged into the Town of Ontario waste water treatment system.

7.2.3 Entrainment and Impingement Impacts

The Ginna Station SPDES permit currently allows the withdrawal from Lake Ontario of 520 million gallons per day (MGD). Ginna Station is equipped with 2 CWS pumps and 4 SW pumps. Under normal operations, Ginna Station withdraws 511 MGD (both CWS pumps and 3 SW pumps operating) during summer months and only 350 MGD (both CWS pumps and 2 SW pumps operating) during winter months. The lower cooling water flows during the winter months are due to recirculation of the CWS discharge back to the screenhouse. The permitted limit of 520 MGD bounds the unlikely scenario where lake levels drop below 244 feet msl, which would require the operation of the fourth SW pump.

No changes to the cooling water intake flow rate would occur as a result of the proposed EPU; therefore, there would be no associated increase in entrainment of planktonic organisms or in the impingement of fish or shellfish.

7.2.4 Thermal Discharge Effects

The Plant's discharges are defined and limited by the provisions of the Ginna Station SPDES Permit (number NY-0000493), effective on February 1, 2003 and expiring February 1, 2008, issued by the New York State Department of Environmental Conservation (NYSDEC).

The SPDES Permit requires monitoring of primary and secondary discharges including the CWS, SW, House Service Boiler Blowdown, the High Conductivity Water Tank and the Radiation Waste Holdup and Treatment System. Discharge limitations exist on flow, maximum and Delta T (ΔT) temperature, chlorine, boron, oil and grease, suspended solids pH, iron, copper, zinc, arsenic and chromium. The plant CWS and SW systems both use chlorine to control biofouling and zebra mussel buildup.

The preferred service water discharge flow path is to the discharge canal, then Lake Ontario. An alternate service water discharge flow path exists via a discharge structure to Deer Creek. This path is infrequently used, primarily during surveillance testing or when maintenance work is required in the preferred service water discharge path. When in use, flows are documented in the monthly Discharge Monitoring Report submitted to the NYSDEC. The only special limitation imposed on use of the alternate discharge flow path is that chlorine injection is not allowed, since this would be an unmonitored release point.

Under proposed EPU operating conditions, the heat rejected at the main condensers would increase, resulting in higher discharge temperatures and increased heat loads at the outfall, consequently increasing the affected thermal discharge plume area to Lake Ontario. The discharge temperature would increase 3°F over the existing SPDES permit limit of 102°F. Under current operating conditions, the normal temperature increase over ambient water (ΔT) at the point of discharge is about 20°F during summer months and can reach 28°F during winter months. The higher ΔT during the winter months is primarily due to recirculation of heated water from the discharge canal (described earlier). The current SPDES permit allows a ΔT of 28°F. As a result of implementing the proposed EPU, the ΔT would be about 25°F during the summer months and would reach as high as 35°F during the winter months.

Ginna LLC commissioned studies in 2004 to analyze the effect of the proposed EPU on water temperatures and the temperature distribution in the near- and far-field areas associated with the discharge, and to assess those increases on selected aquatic species. The affected thermal discharge plume area is described as the size of the mixing zone, which is the area where surface water temperatures may exceed 3°F above ambient temperature before the addition of artificial heat. The thermal discharge plume study evaluated the thermal discharge, under existing and proposed EPU conditions, using a state of the art, far-field hydrodynamic and thermal model (ECOM) and a near-field plume model (CORMIX) to determine the near- and far-field temperature rise. The thermal plume modeling studies utilized historical data (intake temperatures, discharge temperatures, plant operating conditions, and meteorological conditions) and data collected from in-situ studies to statistically map the thermal discharge.

The model confirmed that during both summer and winter months, the thermal discharge plume is less than 300 acres under current operating conditions, which is below the SPDES Permit mixing zone limit of 320 acres. The thermal model demonstrates that the thermal discharge plume under the proposed EPU operating conditions would not exceed the current permit limit of 320 acres, except for a couple of days (cumulative) under the most extreme lake and meteorological conditions. Under these extreme conditions, the model predicted the average size of the thermal discharge plume may reach 360 acres. Details of the thermal plume modeling studies are provided in the *R.E. Ginna Station Demonstration Submittal for the SPDES Permit Modification Request in Support of the Ginna Station Extended Power Uprate* to be submitted to NYSDEC concurrent with the EPU License Amendment Request to NRC. In the NYSDEC submittal, Ginna LLC will request a SPDES permit modification to accommodate the increase in discharge temperature, the increase in ΔT, and the increase in the allowable mixing zone to support operations under the proposed EPU.

7.2.5 Thermal Impacts on Aquatic Biota

Increased cooling water temperature is the only environmental impact initiator associated with the proposed Ginna Station EPU that is of particular concern with respect to the aquatic biota. The proposed EPU would not involve any other notable changes to the aquatic environment and, as noted above, no change in cooling water flow or impingement/entrainment rates are associated with the proposed EPU. NRC's generic evaluation of environmental impacts from continued operation of U.S. nuclear generating stations (NUREG-1437) indicates that adverse thermal impacts on aquatic organisms other than fish (and shellfish at some plants), e.g., phytoplankton, zooplankton, and benthic macroinvertebrates, are not expected to be significant at any operating nuclear plant. The NRC confirmed this generic conclusion with respect to continued operation of Ginna Station in NUREG-1437, Supplement 14.

In light of these observations, adverse impacts on aquatic biota of potential concern from the proposed Ginna Station EPU are those related to the effects of increased cooling water discharge temperature on Lake Ontario fishes. This concern is addressed in a biological assessment included in the SPDES permit modification demonstration submittal cited in Section 7.2.4 of this report. The assessment includes a review of thermal tolerance literature for the following ten RIS identified by NYSDEC that occur in Lake Ontario in the vicinity of Ginna Station:

- <u>Warmwater Species</u> - smallmouth bass, spottail shiner, American eel

- <u>Coolwater Species</u> - alewife, yellow perch, threespine stickleback
- <u>Coldwater Species</u> - brown trout, rainbow smelt, lake trout, rainbow trout

The assessment also considers results of fish impingement and entrainment studies at Ginna Station, referenced in Section 7.2.1 of this report, which provide an indication of the seasonal presence and abundance of fish species in the vicinity of the station and thus potential for exposure to increased water temperatures resulting from the proposed EPU. The assessment concludes that there would be no significant adverse impact on fish populations in the vicinity of Ginna Station from increased thermal input resulting from the proposed EPU. Considerations relevant to this conclusion include the following:

- Results of Ginna Station impingement and entrainment monitoring studies in comparison to results of other studies indicate that fish species that occur in Lake Ontario in the vicinity of the station are common components of the local fish community and typical of fish communities found along the nearshore areas of Lake Ontario's southern shoreline. Ichthyoplankton collected in Lake Ontario near the site and other nearshore habitats in the lake consist predominantly of alewife larvae, indicating that alewife spawning locations are ubiquitous in the nearshore zone. Ginna Station is not adjacent to any significant bays or other habitat features that may provide unique or important spawning or nursery areas.
- Thermal mapping and modeling studies reported in the SPDES permit modification demonstration show that cooling water discharge temperatures drop rapidly in the near-field portion of the thermal plume (i.e., within 500 feet of the discharge canal outfall to the lake) and that the plume tends to remain on the lake surface as it extends into the lake. Field measurements and mapping indicates that significantly lower temperatures occur at a depth of 5 feet and on either side of the plume centerline within 75 feet of the canal outfall. Therefore, cooler areas for refuge are readily available to fish that occur in the cooling water discharge.
- Modeling studies indicate that the thermal plume configuration is affected by a variety of factors, including wind speed and direction, and is thus dynamic. Although the plume (as defined by the 3°F above ambient isotherm) under proposed EPU conditions may occupy an area of as much as 320 acres (up to 360 acres for an equivalent of a couple of days – during extreme summer conditions), it generally extends no more than 1 to a few feet below the surface in the far-field area, providing a zone of passage for fish.
- Comparison of thermal preferenda for the ten RIS in relation to cooling water discharge temperatures indicates that all of these species may be attracted to the discharge canal or thermal plume in the winter months. However, potential for cold shock is minimized by station procedures that call for gradual shutdown and reductions in cooling water temperature. In addition, no cold shock incidents are known to have occurred at Ginna Station.
- Fish tend to avoid temperatures exceeding their thermal preferenda and, as noted above, adequate avenues are available for fish in the ambient lake to avoid or escape those areas at the discharge canal outfall and plume that are at or above their thermal preferenda. Therefore, individuals with swimming capability are expected to avoid the discharge canal and areas of the thermal plume that have potential for heat shock.
- Increased mortality from heat shock is a potential concern for impinged fish that are returned to the discharge canal and, therefore, subject to cooling water discharge temperatures at the proposed EPU conditions. However, an examination of upper

thermal tolerance limits for the 10 RIS in relation to cooling water discharge temperatures under winter and summer EPU conditions (at 100 percent of authorized power level), monthly impingement data, and the short duration of potential exposure to these elevated temperatures (i.e., 20-50 seconds transit time in the discharge canal) indicates that EPU-induced increases in mortality of these returned fish would not be significant. In particular:

- Warmwater RIS - Cooling water temperatures in the discharge canal under proposed EPU operating conditions generally would be below upper incipient lethal limits (i.e, temperatures at which 50 percent of the population are not expected to survive for an extended period of time) and within the thermal tolerance zone for all three warmwater RIS (spottail shiner, smallmouth bass, and American eel) throughout the year. In addition, impingement rates for all three species are relatively low in that they each constitute less than 2 percent of total individuals impinged at the station annually.

- Coolwater RIS - Cooling water temperatures in the discharge canal under proposed EPU conditions generally would be below upper incipient lethal limits and within the thermal tolerance zone for alewife and yellow perch throughout the year. This is also the case for threespine stickleback except at intake temperatures (i.e., ambient lake or acclimation temperatures) above approximately 55°F, typically corresponding to the period June – October. However, impingement rates are typically low throughout this warmer period, and most impingement occurs in November-April, when water temperatures are cooler. In 2004, for example, approximately 75 percent of threespine sticklebacks were impinged when intake water temperature was less than 40°F, and few or none were impinged when intake temperature was greater than 60°F.

- Coldwater RIS – As is the case for current station operating conditions, cooling water temperatures in the discharge canal under proposed EPU conditions generally would be above upper incipient lethal limits for three of the four coldwater RIS (brown trout, rainbow trout, lake trout) during part of the year. This would be the case when intake water is in the range of 35-45°F during winter operating conditions, and periods when intake temperatures are above approximately 50°F during summer operating conditions. However, based on data from 2000-2004, impingement rates for these three species are relatively low (less than 2 percent of total individuals impinged at the station annually), and an average of less than 15 individuals each of brown trout and rainbow trout are impinged annually.

  Under current operating conditions, discharge canal temperatures are above the upper incipient lethal temperature for rainbow smelt except when intake water temperature is below approximately 40°F. Under proposed EPU conditions, the upper incipient lethal temperature for this species would be exceeded in the canal throughout the year.

  Lake trout and rainbow smelt differ from the other two coldwater RIS considered in that both are impinged at relatively higher rates and have relatively lower thermal preferenda. A projected average of approximately 560 lake trout and 2,600 rainbow smelt have been impinged annually during 2000-2004. However, relatively few individuals of these two species are impinged at intake temperatures greater than approximately 60°F, the approximate upper limit of their thermal preferenda, indicating these species seek cooler, deeper parts of the lake during those periods.

In 2004, for example, over 80 percent of rainbow smelt were impinged when intake water temperature was less than 40°F, and negligible impingement was noted when intake water temperature was greater than 60°F. Similarly, over 95 percent of lake trout impinged in 2004 were impinged in November and December, months in which average daily intake temperature was less than 50°F. An examination of relevant thermal tolerance data for these two species indicates that the potential to exceed short-term lethal limits for these two species is substantially less during periods when impingement is high compared to those periods when impingement rates are low, particularly when intake temperatures are greater than 60°F.

- Impinged fish that may be introduced to the discharge canal when cooling water discharge temperature exceeds their upper incipient lethal temperatures would be exposed to these temperatures for only a brief period (i.e., 20-50 seconds), reducing potential for associated mortality.
- Finally, potential for significant adverse impact on Lake Ontario fish populations from any EPU-related increase in mortality of fish impinged at Ginna Station is remote considering the very small fraction of these populations that could be lost. As noted in Supplement 14 to NUREG-1437, historical data indicates that Ginna Station impinges an average of only 0.001 percent and 0.0008 percent, respectively, of the lakewide alewife and smelt populations in the lake. Impact determinations for other impinged species are limited to qualitative evaluations due to lack of population estimates. However, impingement rates for these other species have been consistent with lakewide population trends, indicating that population levels are determined by factors other than impingement (see Section 7.2.1 of this report).

- As indicated in Supplement 14 of NUREG-1437 and Section 7.2.1 of this report, alewife is by far the predominant fish larval species present in Lake Ontario in the station vicinity and entrained by the station cooling water system. Additional mortality of alewife larvae resulting from increased cooling water temperatures under proposed EPU conditions is not expected to result in significant adverse impact to the Lake Ontario alewife population, considering the high fecundity of this species, abundance of alewife larvae and ubiquity of spawning in nearshore areas of the lake, and the fact that environmental factors other than entrainment are operative in determining the population levels of this species (see Section 2.2.5 in Supplement 14 of NUREG-1437 and Section 7.2.1 of this report).

7.2.6 Sensitive Aquatic Species

No sensitive aquatic species are known to inhabit or frequent the site. Ginna Station is not adjacent to any significant bays or other habitat features that may provide unique or important spawning or nursery areas. There are no aquatic species Federally listed as threatened or endangered under the Endangered Species Act in the vicinity of the Ginna Station site. As noted by NRC in NUREG-1437, Supplement 14, there are two State-listed aquatic species known to occur within Wayne County, the pugnose shiner (*Notropis anogenus*) and the lake sturgeon (*Acipenser fulvescens*). However, no threatened or endangered aquatic species, including State-listed species, have been reported during the 35 years of impingement monitoring at the Station. Therefore, the proposed EPU would not affect any New York State-listed or Federally listed aquatic threatened or endangered species.

8.0 Radiological Environmental Impacts

8.1 Radiological Waste Streams

The radioactive waste systems at Ginna Station are designed to collect, process, and dispose of radioactive wastes in a controlled and safe manner. The design basis for these systems during normal operations is to limit discharges in accordance with 10 CFR 50, Appendix I. Adherence to these limits and objectives would continue under the proposed EPU.

Operation at the proposed EPU conditions would not result in any physical changes to the solid waste, liquid waste, or gaseous waste systems. The safety and reliability of these systems would be unaffected by the proposed EPU. Also, the proposed action would not affect the environmental monitoring of any of these waste streams or the radiological monitoring requirements of the Ginna Station Radiation Protection Program. Under normal operating conditions, the proposed action would not introduce any new or different radiological release pathways and would not increase the probability of an operator error or equipment malfunction that would result in an uncontrolled radioactive release from the radioactive waste streams. LR Section 2.5.6, "Waste Management Systems" provides a detailed evaluation of effects that the proposed EPU may have on the solid, liquid and gaseous radioactive waste systems. The following subsections summarize the conclusions of these sections and compare the results against the impacts of the radiological waste system documented in the FES.

8.1.1 Solid Waste

Solid radioactive wastes include solids recovered from the reactor-coolant systems, solids in contact with the reactor process system liquids or gases, and solids used in the reactor-coolant system operation. LR Section 2.5.6.3, "Solid Waste Management System" provides a detailed evaluation of effects the proposed EPU may have on the solid waste management system. The largest volume of solid radioactive waste at Ginna Station is low-level radioactive waste (LLRW). The types of LLRW at Ginna Station include sludge, oily waste, bead resin, spent filters, and dry active waste (DAW) from outages and routine maintenance. DAW includes paper, plastic, wood, rubber, glass, floor sweepings, cloth, metal, and other types of waste routinely generated during site maintenance and outages. Table 8-1 presents the annual volume of LLRW generated at Ginna Station for the most recent five-year period.

Table 8-1
Low-Level Radioactive Waste Generated at Ginna Station, 2000 – 2004

Year	Volume Generated (ft^3)
2000	4,130
2001	1,499
2002	3,978
2003	7,233
2004	12,709

ft^3 = cubic feet.

The 9-year average annual amount of low-level waste generation during a non-outage year is 2,500 cubic feet, and during an outage year, it is approximately 5,000 cubic feet. The higher volumes indicated in Table 8-1 for year 2003 is due to waste generated as a result of the Auxiliary Building and Intermediated Building roof replacements and the reactor head replacement project. In addition, in year 2004 continued roof replacements and mandated security upgrades yielded an annual volume of LLRW significantly above the normal levels.

The results of the evaluation presented in LR Section 2.5.6.3 indicate that the proposed EPU has no significant effect on the generation of solid waste volume from the primary and secondary side systems since the systems functions are not changing and the volume inputs remain the same. As noted in Table 8-1 and discussed above, the generation volumes are well below the annual generation rate of 16,000 cubic feet used in the FES (AEC 1973, page 3-27). The proposed EPU would result in a small increase in the equilibrium radioactivity in the reactor coolant which in turn would impact the concentrations of radioactive nuclides in the waste disposal systems. Section 8.2 addresses the impact of the increase in activity on dose.

8.1.2 Liquid Waste

Liquid radioactive wastes include liquids from the reactor process systems and liquids that have become contaminated with process system liquids. Table 8-2 presents liquid releases from Ginna Station for the most recent five-year period. As noted in Table 8-2, 23.8 million gallons and 2.13 millicuries of fission and activation products were released in the year 2003. Ginna LLC assumes the volume to be valid for future normal operations, because as indicated in LR Section 2.5.6.2, "Liquid Waste Management System" the proposed EPU implementation would not significantly increase the inventory of liquid normally processed by the liquid waste management system. This conclusion is based on the fact that system functions are not changing and the volume inputs remain the same. The proposed EPU would result in a small increase in the equilibrium radioactivity in the reactor coolant which in turn would impact the concentrations of radioactive nuclides in the waste disposal systems. However, the releases would remain bounded by the FES (AEC 1973), which estimated liquid effluent releases, excluding tritium, of about 0.9 curies per year. The FES estimated about 350 curies of tritium per year would be released from the Ginna Station. Section 8.2 addresses the impact of increase activity on dose.

Table 8-2
Liquid Effluent Releases from Ginna Station, 1999 – 2003

Year	Volume Released (gallons)	Activity Released (Ci)	Tritium (Ci)
1999	26,300,000	2.29E-02	195
2000	28,200,000	4.75E-03	390
2001	31,900,000	1.04E-03	202
2002	48,600,000	1.57E-02	241
2003	23,800,000	2.13E-03	339

Sources: RGE 1999, 2000, 2001, 2002b, 2003.
Ci = curies.

8.1.3 Gaseous Waste

Gaseous radioactive wastes principally include activation gases and fission product radioactive noble gases resulting from process operations, gases used for tank cover gas, gases collected during venting, and gases generated in the radiochemistry laboratory. Table 8-3 presents gaseous releases from Ginna Station for the most recent five-year period. The evaluation presented in LR Section 2.5.6.1, "Gaseous Waste Management Systems" indicates that implementation of the proposed EPU does not significantly increase the inventory of gas normally processed in the gaseous waste management system since plant system functions are not changing and the volume inputs remain the same. However, the proposed EPU would result in an increase in the equilibrium radioactivity in the reactor coolant, which in turn increases the activity in the waste disposal systems. The year 2003 release values are assumed to be a valid representation of future normal operations, and remain bounded by the FES (AEC 1973), which estimated gaseous effluent releases of about 2,350 curies per year for noble gases and 0.162 curies per year for iodines. Section 8.2 addresses the offsite radiation dose consequences of these effluent releases.

Table 8-3
Gaseous Effluent Releases from Ginna Station, 1999 – 2003

Year	Noble Gases (Ci)	Particulates and Iodines (Ci)	Tritium (Ci)
1999	121	1.79E-04	44
2000	532	3.84E-04	42
2001	35	4.91E-05	32
2002	32	7.70E-05	54
2003	35	1.13E-04	49

Sources: RGE 1999, 2000, 2001, 2002b, 2003.
Ci = curries.

8.2 Radiation Levels and Offsite Dose

8.2.1 Operating and Shutdown In-Plant Levels

In-plant radiation levels and associated doses are controlled by the Ginna Station Radiation Protection Program to ensure that internal and external radiation exposures to station personnel, contractor personnel, and the general population will be as low as reasonably achievable (ALARA), as required by 10 CFR 20. Ginna LLC has a policy of maintaining occupational dose equivalents to the individual and the sum of dose equivalents received by all exposed workers to ALARA levels.

LR Section 2.10.1.2.1, "Normal Operation Radiation Levels and Shielding Adequacy" provides a detailed analysis of the impact of the proposed EPU on radiation levels and shielding adequacy and the resulting occupational dose. The analysis considered the impact of increasing the core power level on neutron flux and gamma flux in and around the core, fission product and actinide activity inventory in the core and spent fuels, N-16 source in the reactor coolant, neutron activation source in the vicinity of the reactor core, and fission/corrosion products activity in the reactor coolant and downstream systems. The results indicate that in-plant radiation sources are anticipated to increase linearly with the increase in core power level. Shielding is used throughout the Plant to protect personnel against radiation emanating from the reactor and their auxiliary systems, and to limit radiation damage to operating equipment. Ginna LLC has determined that the current shielding designs would be adequate for the increase in radiation levels that may occur after the proposed EPU. The increase is offset by:

a. conservative analytical techniques typically used to establish shielding requirements,
b. conservatism in the original "design basis" reactor coolant source terms used to establish the radiation zones, and
c. plant Technical Specifications that limit the reactor coolant concentrations to levels below or equal to the original design basis source terms.

For the proposed EPU, normal operation radiation levels would increase by no more than the percentage increase of EPU. For conservatism, many aspects of the Plant were originally designed for higher-than-expected radiation sources. Thus, the increase in radiation levels would not affect radiation zoning or shielding in the various areas of the Plant because it is offset by conservatism in the original design, source terms used, and analytical techniques. Therefore, no new dose reduction programs are planned and the ALARA program would continue in its current form.

8.2.2 Offsite Doses at Power Uprate Conditions

LR Section 2.10.1.2.4, "Normal Operation Radwaste Effluents and Annual Dose to the Public," provides a detailed analysis of the impact of the proposed EPU on offsite doses using scaling techniques based on NUREG-0017, Revision 1 methodology (NRC). This analysis conservatively projects maximum doses from normal operation under the proposed EPU conditions using the following:

- plant core power operating history during years 1999 through 2003,
- the reported gaseous and liquid effluent and dose data during that period,
- NUREG-0017 equations and assumptions, and
- conservative methodology.

Base case doses were calculated by taking the average five-year doses (organ and whole body) coupled with annual core power levels and extrapolating the doses to that equivalent to 100 percent capacity. To predict doses under the proposed EPU conditions, the analysis assumes that the maximum increase in radioactivity content of the liquid and gaseous releases is proportional to the uprate percentage increase.

Offsite doses from liquid effluents are summarized and averaged for 1999 through 2003 (Table 8-4), according to 10 CFR 50, Appendix I. For the five-year period, average annual whole body dose extrapolated to 100 percent capacity was 3.16E-03 mrem, and average annual dose to the critical organ (thyroid) was 3.37E-03 mrem. Assuming the increase in radioactivity content as a result of the proposed EPU is linear, Ginna LLC predicts the maximum annual total body and organ doses (all pathways) from liquid effluent releases are 3.77E-03 mrem and

Table 8-4
Radiation Doses from Liquid Effluent Pathways, 1999-2003
(Maximum Adult Individual Dose, mrem)

	1999[a]	2000[a]	2001	2002	2003	Base Case Average Dose[b] (limit)
Organ (thyroid)	1.29E-03	2.59E-03	1.21E-03	1.86E-03	2.22E-03	3.37E-03 (10)
Whole Body	1.32E-03	2.60E-03	1.21E-03	1.86E-03	2.22E-03	3.16E-03 (3)

Sources: RGE 1999, 2000, 2001, 2002b, and 2003.

a. Doses for 1999 and 2000 have been recalculated from values reported in RGE 1999 and 2000 following revision of the Ginna Station Offsite Dose Calculation Manual guidelines to meet NUREG-1301.

b. Base Case Average Dose represents the annual average dose for the period 1999 through 2003 extrapolated to 100 percent plant operating capacity.

mrem = millirem.

4.01E-03 mrem, respectively, which are well below the regulatory standards contained in 10 CFR 50, Appendix I. These doses would also be bounded by the FES (AEC 1973), which predicted a maximum offsite whole body dose from all pathways of 7.08E-02 mrem per year and a maximum organ dose (thyroid) of 5.3E-02 mrem per year.

Does to individuals from gaseous releases are summarized and averaged for 1999 through 2003 (Table 8-5) according to 10 CFR 50, Appendix I. For the five-year period, average annual whole body dose at the site boundary extrapolated to 100 percent capacity was 7.06E-03 mrem and average annual dose to the critical organ (skin) was 9.25E-03 mrem. Assuming the increase in radioactivity content as a result of the proposed EPU is linear, Ginna LLC predicts the maximum annual total body and organ doses (all pathways) from gaseous effluent releases are 8.41E-03 mrem and 1.10E-02 mrem, respectively, which are well below the regulatory standards contained in 10 CFR 50, Appendix I. These doses would also be bounded by the FES (AEC 1973), which predicted an maximum offsite whole body dose from all pathways of 3.6E-01 mrem per year and a maximum organ dose (skin) of 1.4E+00 mrem per year.

Table 8-5
Radiation Doses from Gaseous Effluent Pathways, 1999-2003
(Maximum Adult Individual Dose, mrem)

	1999	2000	2001	2002	2003	Base Case Average Dose[a] (limit)
Organ (skin)	4.01E-03	3.80E-03	2.34E-02	4.31E-03	3.85E-04	9.25E-03 (15)
Whole Body	5.60E-03	2.45E-03	1.30E-02	2.93E-03	2.36E-04	7.06E-03 (5)

Sources: RGE 1999, 2000, 2001, 2002b, and 2003.

a. Base Case Average Dose represents the annual average dose for the period 1999 through 2003 extrapolated to 100 percent plant operating capacity.

mrem = millirem

9.0 Environmental Effects of Uranium Fuel Cycle Activities and Fuel and Radioactive Waste Transport

NRC regulations 10 CFR 51.51 (Table S-3) provide the basis for evaluating the contribution of the environmental effects of the uranium fuel cycle to the environmental impacts of licensing a nuclear power plant. NRC regulations 10 CFR 51.52 (Table S-4) describe the environmental impacts of transporting nuclear fuel and radioactive wastes. The tables were developed in the 1970s. Since that time, most plants have increased both their uranium-235 enrichment and the fuel's burnup limits.

In 1988, NRC generically evaluated the impacts of extended burnup fuel and increased enrichment on the uranium fuel cycle, including transportation of nuclear fuel and wastes, to determine whether higher burnup and enrichment could result in environmental impacts greater than those derived in Tables S-3 and S-4. The environmental assessment and finding of no significant impact (53 FR 6040, February 29, 1988) concluded that burnup limits of up to 50,000 megawatt-days per metric ton of uranium (MWd/MTU) or higher (as long as the maximum rod average burnup level of any fuel rod is no greater than 60,000 MWd/MTU) and uranium-235 enrichment up to 5 weight percent would have no significant adverse environmental effects on the uranium fuel cycle or the transport of nuclear fuel and wastes, and would not change the impacts presented in Tables S-3 and S-4.

In 1999, in connection with the Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants, NRC reviewed transporting higher enrichment and higher burnup fuel to a geologic repository (NRC 1999). The conclusion of that evaluation was that Table S-4 applies to spent fuel enriched up to 5 percent uranium-235 with average burnup for the peak rod to current levels approved by NRC up to 62,000MWd/MTU, provided higher burnup fuel is cooled for at least 5 years before being shipped.

Ginna Station is currently licensed to use uranium-dioxide fuel that has a maximum enrichment of 5.0 percent by weight of uranium-235. The typical average enrichment for a fuel reload has increased over the life of the station as cycle lengths have increased and is now approximately 4.8 percent. For the proposed action, the uprate core design would use a marginally higher average fuel enrichment (up to 4.95 percent), which is bounded by the licensed maximum enrichment.

The current core design is composed of fuel rods fabricated with cylindrical, uranium dioxide ceramic pellets enclosed in approximately 142-inch-long cylindrical, Zircaloy or ZIRLO tubes with welded end plugs. The 179 fuels rods are fabricated into 14 x 14 array fuel assemblies with end fittings and grids to support and limit motion of the tubes. There are 121 of these fuel assemblies in the reactor core. The uprate core design also involves a modified fuel assembly very similar to that in use for the past several operating cycles at Point Beach and Kewaunee nuclear power plants, Westinghouse "sister" plants to Ginna Station. The modified fuel assembly would contain longer and larger diameter fuel rods to allow the use of more uranium to produce the higher power. As a result of the longer fuel rod, a new and shorter top nozzle would be used that would also necessitate modification of the fuel handling equipment. The modified assembly also includes a new grid design that has lower flow resistance that allows for greater coolant flow and thermal margin.

Ginna LLC replaces about one-third (44) of the fuel assemblies in the reactor core at approximately 18-month intervals. The refueling schedule would remain the same under the proposed action. During the Fall 2006 refueling outage, the new core design for the uprate would be loaded for about one third of the core. The average fuel assembly discharge burnup would be approximately 52,000 MWd/MTU with no fuel pins exceeding the maximum fuel rod limit of 62,000 MWd/MTU. Reload design goals would maintain the Ginna Station fuel cycles within the limits bounded by the impacts analyzed in Tables S-3 and S-4. Therefore, Ginna LLC concludes that impacts to the uranium cycle and transport of nuclear fuel from the proposed action would be insignificant and not require mitigation.

10.0 Effects of Decommissioning

The FES for Ginna Station did not evaluate the environmental effects of decommissioning. In 1988, NRC published the Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities (NUREG-0586; NRC 1988) that discusses decommissioning of nuclear power plants. Procedures for decommissioning a nuclear power plant are found in NRC regulations at 10 CFR 50.75, 50.82, 51.23, and 51.95. In addition, NRC is considering new rulemaking to address certain aspects of decommissioning.

Prior to any decommissioning activity at Ginna Station, Ginna LLC would submit a post-shutdown decommissioning activities report to describe planned decommissioning activities, any environmental impacts of those activities, a schedule, and estimated costs. Implementation of an EPU does not affect Ginna LLC's ability to maintain financial reserves for decommissioning.

The potential environmental impacts on decommissioning associated with the proposed EPU would be due to the increased neutron fluence. As a result, the amount of activated corrosion products could increase, and consequently, the post-shutdown radiation levels could increase. Ginna LLC expects the increases in radiation levels as a result of operations under the proposed EPU conditions to be insignificant, and would be addressed in the post-shutdown decommissioning activities report.

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Attachment 9

R.E. Ginna Nuclear Power Plant

Regulatory Commitments

REGULATORY COMMITMENTS

The following table identifies those actions committed to by R.E. Ginna Nuclear Power Plant, LLC in this document. Any other statements in this submittal are provided for information purposes and are not considered to be regulatory commitments. Please direct questions regarding these commitments to George Wrobel, Nuclear Safety and Licensing at (585) 771-3535.

REGULATORY COMMITMENT	DUE DATE
Update flow-accelerated/erosion-corrosion program to account for higher EPU flowrates. (Licensing Report Section 2.1.8)	Prior to startup from the fall 2006 refueling outage.
Modify fatigue monitoring program to incorporate EPU conditions. (Licensing Report Section 2.2.2)	Prior to startup from the fall 2006 refueling outage.
Modify inservice inspection and inservice testing programs to account for new SSCs and conditions. (Licensing Report Section 2.2.4 and 2.5.5.1)	Prior to startup from the fall 2006 refueling outage.
Implement modifications and procedure changes to incorporate App. R mitigation strategies. (Licensing Report Section 2.5.1.4)	Prior to startup from the fall 2006 refueling outage.
Revise environmental qualification files to document modified EQ parameters. Include continuation of local temperature monitoring program in containment for qualified life assessments. Resolve the impact of localized containment fan cooler HEPA filter dose. (Licensing Report Section 2.3.1)	Prior to startup from the fall 2006 refueling outage.
Provide training (especially for operator timeline changes) and make procedure changes as needed to account for higher decay heat levels, especially as related to RHR, CCW, SFPC, AFW, SW systems. (Licensing Report Section 2.8.7.3 and 2.11)	Prior to startup from the fall 2006 refueling outage.
Provide simulator changes and training to account for increased power level and resultant plant changes. (Licensing Report Section 2.11)	Prior to startup from the fall 2006 refueling outage.

Modify licensing basis for Service Water train operability from 1 to 2 pumps. (Licensing Report Section 2.5.4)	Prior to startup from the fall 2006 refueling outage.
Implement risk-beneficial modifications to Charging, SI, and RHR systems. (Licensing Report Section 2.13)	Prior to startup from the fall 2006 refueling outage.
Modify control and indication setpoints as needed for operation at EPU conditions. (Licensing Report Section 2.4.2, 2.8.4.1, and 2.8.5)	Prior to startup from the fall 2006 refueling outage.
Maintain vibration monitoring program during power ascension testing. (Licensing Report Section 2.5.5.1)	Prior to startup from the fall 2006 refueling outage.
Perform a detailed evaluation of additional large plant transient tests beyond those described in Licensing Report Section 2.12.	Prior to September 30, 2005