Exelon Generation
4300 Winfield Road
Warrenville, IL 60555

www.exeloncorp.com

Exelon Nuclear

RS-01-303

December 17, 2001

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

Dresden Nuclear Power Station, Units 2 and 3
Facility Operating License Nos. DPR-19 and DPR-25
NRC Docket Nos. 50-237 and 50-249

Quad Cities Nuclear Power Station, Units 1 and 2
Facility Operating License Nos. DPR-29 and DPR-30
NRC Docket Nos. 50-254 and 50-265

Subject: Revision to Proprietary Designation - Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation, Dresden Nuclear Power Station and Quad Cities Nuclear Power Station

References: (1) Letter from R. M. Krich (Commonwealth Edison Company) to U. S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000

(2) Letter from K. A. Ainger (Exelon Generation Company, LLC) to U. S. NRC, "Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station," dated August 13, 2001

In Reference 1, Commonwealth Edison Company, now Exelon Generation Company (EGC), LLC, submitted a request for changes to the operating licenses and Technical Specifications for Dresden Nuclear Power Station, Units 2 and 3, and Quad Cities Nuclear Power Station, Units 1 and 2, to allow operation at uprated power levels. In Reference 2, we provided additional information regarding these proposed changes. Some of the information in the attachment to Reference 2 was designated as proprietary by the General Electric (GE) Company and we requested that it be withheld from public disclosure in accordance with 10 CFR 2.790(a)(4), "Public Inspections, Exemptions, Requests for Withholding."

In a telephone conference on December 7, 2001, between Mr. G. F. Dick of the NRC and Mr. A. R. Haeger of EGC, the NRC requested that EGC and GE review the proprietary designation of the information in the attachment to Reference 2 and re-submit the

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information with any identified changes to the proprietary designation. Accordingly, GE has revised the proprietary designation of this information. The revised attachment is enclosed as Attachment A to this letter. None of the technical information in Reference 2 has been revised.

Portions of Attachment A contain proprietary information to GE, and EGC requests that it be withheld from public disclosure in accordance with 10 CFR 2.790(a)(4), "Public Inspections, Exemptions, Requests for Withholding." Attachment B contains the affidavit supporting the request for withholding the letter from public disclosure, as required by 10 CFR 2.790(b)(1). Attachment C contains a non-proprietary version of Attachment A.

Should you have any questions related to this letter, please contact Mr. Allan R. Haeger at (630) 657-2807.

Respectfully,

Keith R. Jury

K. R. Jury
Director – Licensing
Mid-West Regional Operating Group

Attachments:

Affidavit
Attachment A: Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation, Dresden Nuclear Power Station, Units 2 and 3, Quad Cities Nuclear Power Station, Units 1 and 2 (Proprietary version)
Attachment B: Affidavit for Withholding Portions of Attachment A from Public Disclosure
Attachment C: Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation, Dresden Nuclear Power Station, Units 2 and 3, Quad Cities Nuclear Power Station, Units 1 and 2 (Non-proprietary version)

cc: Regional Administrator – NRC Region III
NRC Senior Resident Inspector – Dresden Nuclear Power Station
NRC Senior Resident Inspector – Quad Cities Nuclear Power Station
Office of Nuclear Facility Safety – Illinois Department of Nuclear Safety

STATE OF ILLINOIS	**)**	
COUNTY OF DUPAGE	**)**	
IN THE MATTER OF	**)**	
EXELON GENERATION COMPANY, LLC	**)**	**Docket Numbers**
DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3	**)**	**50-237 AND 50-249**
QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2	**)**	**50-254 AND 50-265**

SUBJECT: Revision to Proprietary Designation - Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation, Dresden Nuclear Power Station and Quad Cities Nuclear Power Station

AFFIDAVIT

I affirm that the content of this transmittal is true and correct to the best of my knowledge, information and belief.

Keith R. Jury
K. R. Jury
Director – Licensing
Mid-West Regional Operating Group

Subscribed and sworn to before me, a Notary Public in and

for the State above named, this 17 day of

December, 2001.

Anese L. Grigsby
Notary Public

OFFICIAL SEAL
ANESE L. GRIGSBY
NOTARY PUBLIC, STATE OF ILLINOIS
MY COMMISSION EXPIRES 3-13-2005

Attachment B
Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Affidavit for Withholding Portions of Attachment A from Public Disclosure

General Electric Company

AFFIDAVIT

I, George B. Stramback, being duly sworn, depose and state as follows:

(1) I am Project Manager, Regulatory Services, General Electric Company ("GE") and have been delegated the function of reviewing the information described in paragraph (2) which is sought to be withheld, and have been authorized to apply for its withholding.

(2) The information sought to be withheld is contained in Attachment 1 to letter GE-DQC–EPU-01-492, *Plant Systems RAI 31, Revised Proprietary Bars*, (GE Proprietary Information), dated December 12, 2001. The proprietary information is delineated by bars marked in the margin adjacent to the specific material in the Attachment 1, *GE Response to NRC Plant Systems RAI 31, Revised Proprietary Markings.*

(3) In making this application for withholding of proprietary information of which it is the owner, GE relies upon the exemption from disclosure set forth in the Freedom of Information Act ("FOIA"), 5 USC Sec. 552(b)(4), and the Trade Secrets Act, 18 USC Sec. 1905, and NRC regulations 10 CFR 9.17(a)(4), 2.790(a)(4), and 2.790(d)(1) for "trade secrets and commercial or financial information obtained from a person and privileged or confidential" (Exemption 4). The material for which exemption from disclosure is here sought is all "confidential commercial information", and some portions also qualify under the narrower definition of "trade secret", within the meanings assigned to those terms for purposes of FOIA Exemption 4 in, respectively, Critical Mass Energy Project v. Nuclear Regulatory Commission, 975F2d871 (DC Cir. 1992), and Public Citizen Health Research Group v. FDA, 704F2d1280 (DC Cir. 1983).

(4) Some examples of categories of information which fit into the definition of proprietary information are:

a. Information that discloses a process, method, or apparatus, including supporting data and analyses, where prevention of its use by General Electric's competitors without license from General Electric constitutes a competitive economic advantage over other companies;

b. Information which, if used 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 of a similar product;

c. Information which reveals cost or price information, production capacities, budget levels, or commercial strategies of General Electric, its customers, or its suppliers;

d. Information which reveals aspects of past, present, or future General Electric customer-funded development plans and programs, of potential commercial value to General Electric;

e. Information which discloses patentable subject matter for which it may be desirable to obtain patent protection.

The information sought to be withheld is considered to be proprietary for the reasons set forth in both paragraphs (4)a. and (4)b., above.

(5) The information sought to be withheld is being submitted to NRC in confidence. The information is of a sort customarily held in confidence by GE, and is in fact so held. The information sought to be withheld has, to the best of my knowledge and belief, consistently been held in confidence by GE, no public disclosure has been made, and it is not available in public sources. All disclosures to third parties including any required transmittals to NRC, have been made, or must be made, pursuant to regulatory provisions or proprietary agreements which provide for maintenance of the information in confidence. Its initial designation as proprietary information, and the subsequent steps taken to prevent its unauthorized disclosure, are as set forth in paragraphs (6) and (7) following.

(6) Initial approval of proprietary treatment of a document is made by the manager of the originating component, the person most likely to be acquainted with the value and sensitivity of the information in relation to industry knowledge. Access to such documents within GE is limited on a "need to know" basis.

(7) The procedure for approval of external release of such a document typically requires review by the staff manager, project manager, principal scientist or other equivalent authority, by the manager of the cognizant marketing function (or his delegate), and by the Legal Operation, for technical content, competitive effect, and determination of the accuracy of the proprietary designation. Disclosures outside GE are limited to regulatory bodies, customers, and potential customers, and their agents, suppliers, and licensees, and others with a legitimate need for the information, and then only in accordance with appropriate regulatory provisions or proprietary agreements.

(8) The information identified in paragraph (2), above, is classified as proprietary because it contains further details regarding the GE proprietary report NEDC-32961P, *Safety Analysis Report for Quad Cities 1 & 2 Extended Power Uprate,* Class III (GE Proprietary Information), dated December 2000, and NEDC-32962P, *Safety Analysis Report for Dresden 2 & 3 Extended Power Uprate,* Class III (GE

Proprietary Information), dated December 2000, which contain detailed results of analytical models, methods and processes, including computer codes, which GE has developed, obtained NRC approval of, and applied to perform evaluations of transient and accident events in the GE Boiling Water Reactor ("BWR").

The development and approval of these system, component, and thermal hydraulic models and computer codes was achieved at a significant cost to GE, on the order of several million dollars.

The development of the evaluation process along with the interpretation and application of the analytical results is derived from the extensive experience database that constitutes a major GE asset.

(9) Public disclosure of the information sought to be withheld is likely to cause substantial harm to GE's competitive position and foreclose or reduce the availability of profit-making opportunities. The information is part of GE's comprehensive BWR safety and technology base, and its commercial value extends beyond the original development cost. The value of the technology base goes beyond the extensive physical database and analytical methodology and includes development of the expertise to determine and apply the appropriate evaluation process. In addition, the technology base includes the value derived from providing analyses done with NRC-approved methods.

The research, development, engineering, analytical and NRC review costs comprise a substantial investment of time and money by GE.

The precise value of the expertise to devise an evaluation process and apply the correct analytical methodology is difficult to quantify, but it clearly is substantial.

GE's competitive advantage will be lost if its competitors are able to use the results of the GE experience to normalize or verify their own process or if they are able to claim an equivalent understanding by demonstrating that they can arrive at the same or similar conclusions.

The value of this information to GE would be lost if the information were disclosed to the public. Making such information available to competitors without their having been required to undertake a similar expenditure of resources would unfairly provide competitors with a windfall, and deprive GE of the opportunity to exercise its competitive advantage to seek an adequate return on its large investment in developing these very valuable analytical tools.

STATE OF CALIFORNIA)
) ss:
COUNTY OF SANTA CLARA)

George B. Stramback, being duly sworn, deposes and says:

That he has read the foregoing affidavit and the matters stated therein are true and correct to the best of his knowledge, information, and belief.

Executed at San Jose, California, this 12th day of December 2001.

George B. Stramback
George B. Stramback
General Electric Company

Subscribed and sworn before me this 12th day of December 2001.

TERRY J. MORGAN
Commission # 1304914
Notary Public - California
Santa Clara County
My Comm. Expires May 18, 2005

Terry J. Morgan
Notary Public, State of California

Attachment C
Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation (Non-Proprietary)
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation (non-proprietary version)

Attachment C
Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation (Non-Proprietary)
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

This attachment contains responses to NRC Questions 9, 10, 11, 13, 14, 16, 17 (Dresden Nuclear Power Station), 31, 32, and 33. Responses to NRC Questions 1 through 8, 12, 15, and 17 through 30 were provided in a previous submittal (Reference 1).

<u>Question</u>
9. Provide the emergency core cooling system (ECCS) pumps net positive suction head (NPSH) calculations to support the requested additional credit for overpressure. Discuss the increased need for containment overpressure for NPSH following a design basis accident. Describe the procedures or equipment in place that will allow continued cooling flow with the drywell potentially depressurized to atmospheric conditions and the suppression chamber at the most conservative pressure associated with vacuum breaker operation (limiting case either torus/drywell or torus/reactor building). Additionally, discuss the methodology for determining the requested containment overpressure, including the headloss across the ECCS suction strainers.

<u>Response</u>
Additional credit for containment overpressure is required because the suppression pool temperature increases at a faster rate and peaks at a higher value compared to the pre-EPU conditions during a loss of coolant accident (LOCA). Because vapor pressure increases as the suppression pool temperature increases, the net positive suction head available (NPSHa) for each ECCS pump is reduced. To offset this reduction in NPSHa, more overpressure credit is required. More overpressure is also available, since the containment and suppression pool pressures also increase at a faster rate and peak at a higher value than before EPU.

<u>Containment Response</u>
The design basis accident (DBA) LOCA containment response for NPSH evaluations is analyzed for two time periods: short term (before 600 seconds), and long term (after 600 seconds). The long term temperature and pressure conditions of the suppression pool are determined based on assumptions that maximize the pool temperature and minimize the overpressure, including operation of containment sprays and vacuum breakers. Specific assumptions include the following.

- The DBA LOCA is an instantaneous double-ended guillotine break of the recirculation suction line at the reactor vessel nozzle safe-end to pipe weld. The effective break area is 4.261 ft^2.

- The reactor is operating at 102% of EPU (i.e., 3016 megawatts thermal (MWt)) with an initial reactor pressure of 1005 pounds per square inch - gauge (psig). Concurrent with occurrence of the break, reactor scram occurs.

- The reactor core power includes fission energy, fuel stored energy, metal-water reaction energy and American Nuclear Society (ANS) Standard 5.1-1979 decay heat with two sigma adder for fuel applicable to GE14 with 24 month fuel cycle.

- The initial suppression pool water volume corresponds to the low water level (LWL) to maximize the suppression pool temperature response.

- Containment cooling is achieved by operating one low pressure coolant injection (LPCI)/ containment cooling (CC) loop at 600 seconds in the containment spray mode (drywell and wetwell sprays). This minimizes the containment pressure response, since cold water sprays will bring down the pressure.

The short term conditions are based on similar assumptions, with the following exceptions.

- There is a single failure of the loop selection logic. Consequently, the flow from all four LPCI pumps goes into the broken recirculation loop and subsequently discharges into the drywell directly. The maximum runout flow rate is assumed.

- Both core spray pumps are operating with the maximum flow rate.

Procedures
Existing plant emergency operating procedures include cautions concerning exceeding ECCS pump NPSH limits. The procedures also contain ECCS pump curves of pump flow versus torus pressure and temperature conditions. The same cautions and NPSH curves are included in the emergency operating procedures that control use of containment sprays. Thus, the operators have sufficient procedural direction to control both ECCS pump flow and containment pressure within limits.

Methodology and Results for DNPS
In discussions with the NRC, it was determined that the requested overpressure credit should be based on the methodology previously approved for DNPS in a 1997 license amendment regarding containment overpressure (Reference 2). This methodology followed the original design basis of one ECCS suction strainer completely blocked, with the remaining three strainers in clean condition. The head loss across the three clean strainers was assumed to be the same as the head loss for the original suction strainers, although those strainers were subsequently replaced with higher capacity strainers. Thus, the assumed headloss is slightly higher than the actual headloss expected with the new strainers. This assumption maintains consistency with the basis for approval of the Reference 2 amendment. EGC also expects that the headloss used to develop the requested overpressure will result in adequate overpressure when compared to the results of future calculations of suction strainer headloss discussed in the paragraph below.

NRC Bulletin 96-03, "Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling-Water Reactors," requested that licensees calculate suction strainer headloss assuming that debris from primary containment is distributed across all of the ECCS suction strainers. In accordance with this request, both DNPS and QCNPS will perform calculations of the suction strainer headloss and will submit a description of the methods and the results to the NRC for DNPS Units 2 and 3 and QCNPS Units 1 and 2.

NPSH calculations have been performed for EPU conditions with the strainer head loss assumptions described above for two short term and two long term flow conditions. The limiting short term ECCS flow case is all four LPCI pumps and both core spray pumps operating at maximum flow conditions. The limiting long term ECCS flow rate is the same as in the 1997 calculations that formed the basis of the currently approved overpressure credit. This limiting flow rate is 19,000 gallons per minute (gpm) distributed as follows: two core spray pumps operating at 4,500 gpm each, one LPCI pump at 5,000 gpm, and two more LPCI pumps at 2,500 gpm each. This flow case is significantly more than the minimum long term flow of 9,750 gpm required to maintain adequate core and containment cooling after EPU. The minimum flow case of one core spray pump operating at 4,750 gpm and one LPCI pump operating at 5,000 gpm is the other case analyzed in the calculations.

The graphs showing the results of the ECCS NPSH calculations for the limiting short term and long term flow cases are provided in Figures 9-1 and 9-2. Core spray flow is the limiting NPSH case in the short term, and LPCI flow is limiting for NPSH in the long term. Figures 9-1 and 9-2 also show NPSH required (NPSHr) for both the old strainer and new strainer cases (e.g., one blocked, three clean). The higher head loss of the old strainers, as indicated above, is the basis for the requested overpressure.

In the short term, there is a period from approximately 290 seconds to 600 seconds during which some ECCS pump cavitation can occur, since the available NPSH is less than the required NPSH. This period is after the time at which the peak cladding temperature (PCT) has been reached at approximately 240 seconds. Prior to 290 seconds, the requested overpressure ensures that adequate NPSH is available to meet the core cooling requirements assumed in the PCT calculations. After 600 seconds, ECCS pump throttling restores adequate NPSH. Pump cavitation for the brief time from 290 seconds to 600 seconds is not of concern due to short duration of the cavitation.

The long term overpressure curves are plotted out to 200,000 seconds. From this point, NPSHa and NPSHr both vary directly as a function of the vapor pressure. The result is that both decrease in parallel fashion, maintaining a margin between available and required NPSH. The use of the described assumptions result in a need for overpressure credit as follows.

Period	Requested Credit (psi)
0 – 290 sec	9.5
290 - 5,000 sec	4.8
5,000 – 30,000 sec	6.6
30,001 - 40,000 sec	6.0
40,001 - 45,500 sec	5.4
45,501 - 52,500 sec	4.9
52,501 - 60,500 sec	4.4
60,501 - 70,000 sec	3.8
70,001 - 84,000 sec	3.2
84,001 - 104,000 sec	2.5
104,001 - 136,000 sec	1.8
136,001 sec – accident end	1.1

A revised proposed containment overpressure for DNPS Unit 3 will be addressed in a future submittal and will use the results of the suction strainer headloss calculations in accordance with NRC Bulletin 96-03 discussed above.

QCNPS

The overpressure credit requested for QCNPS will be addressed in a future submittal, which will use the results of ECCS suction strainer headloss calculations in accordance with NRC Bulletin 96-03 discussed above. These will be performed in support of both the Reference 3 proposed changes and the changes that were proposed in Reference 4 and discussed in the NRC response noted in Reference 5.

Figure 9-1
DNPS Short Term Core Spray NPSH

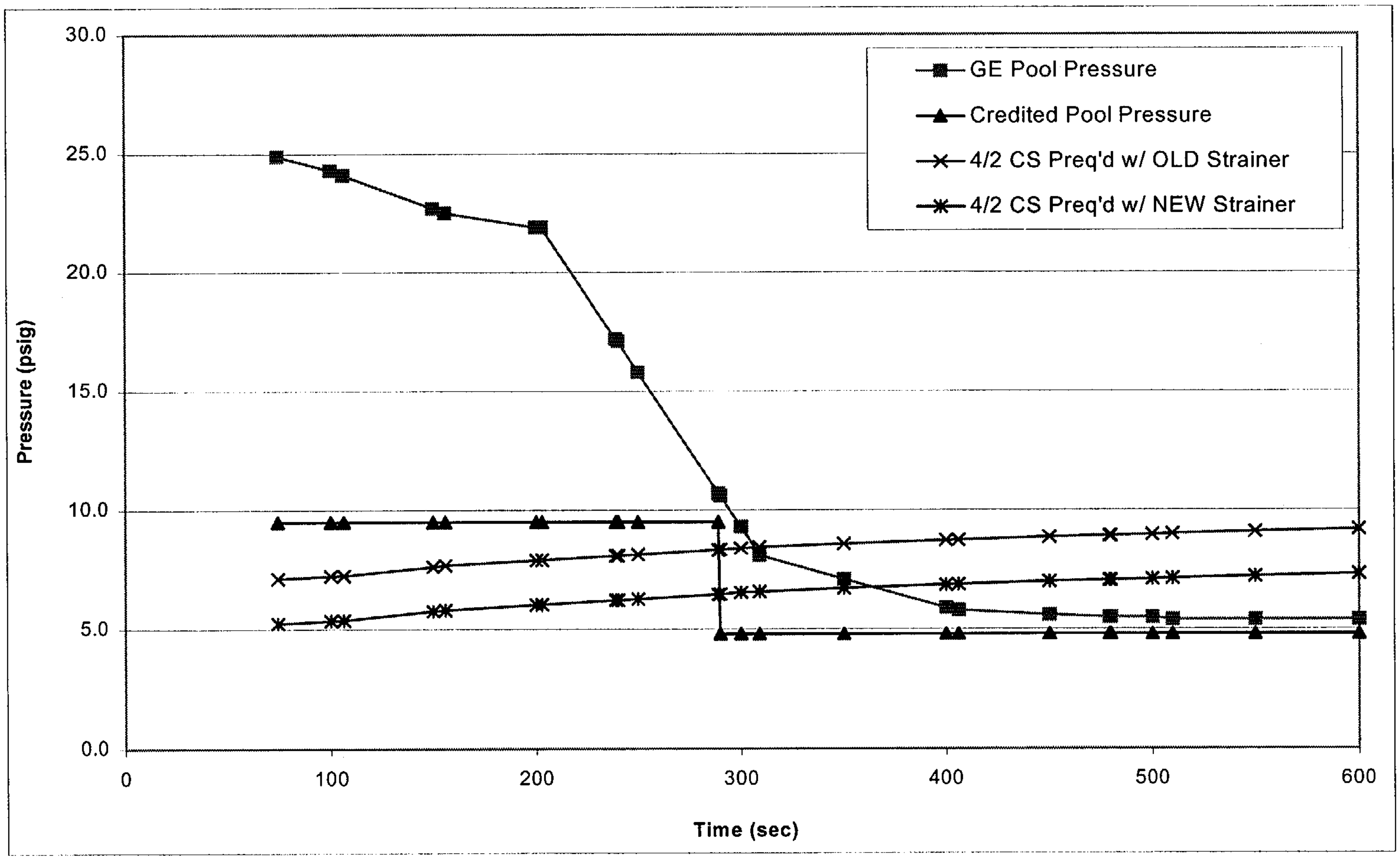
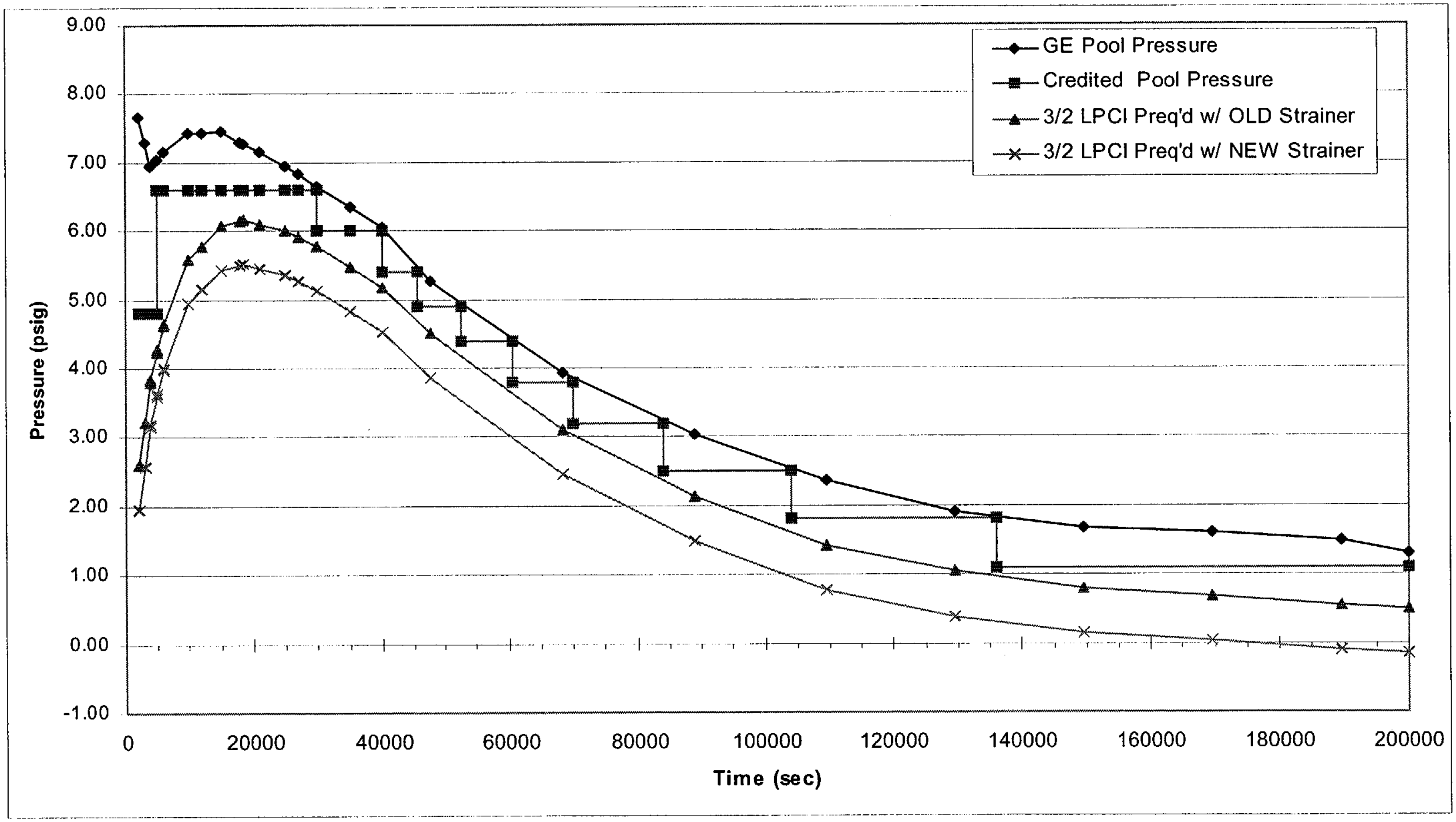


Figure 9-2
DNPS Long Term LPCI NPSH



Attachment C
Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation (Non-Proprietary)
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Question

10. ELTR2 section 4.1.8.5 notes that the higher vapor pressure associated with increased suppression pool temperatures will reduce the NPSH available to the RHR and LPCS pumps and as a result the adequacy of the RHR and LPCS pumps will be evaluated at these increased temperature conditions. Were alternatives other than increased credit for overpressure considered, such as other means to enhance suction pressure, pump replacement or modification?

Response

The significant factors that determine the NPSHa for the ECCS pumps are as follows.

- The relative position and configuration of the associated piping and equipment, which controls suction elevation head and pressure flow losses
- Torus water temperature, which controls vapor pressure
- Torus overpressure, which contributes to suction pressure
- Pump flow rate, which relates to suction pressure losses
- Pump replacement

As discussed in Question 9, minimum pump flow, maximum water temperature and minimum overpressure were used in the NPSHr evaluation.

Changes to piping and equipment configuration and type were not considered as viable alternatives. To improve NPSHa, changes such as suction piping replacement or lowering of the pumps relative to the suppression pool would be required. Such changes are very difficult, require lengthy outages, and are very expensive, and are, therefore, considered impractical.

Question

11. The application is unclear or inconsistent regarding some of the requested changes for the license condition on containment overpressure. Clarify your request for these changes as noted in comment column of the following tables for Dresden and Quad Cities;

Dresden Containment Overpressure Credit (psi)				
Time (seconds)	*Current license condition*	*Requested condition*	*NEDC-32962P Safety Analyses Report*	*Comment*
0-240	*9.5*			
0-290		*9.5*	*9.5*	
240-480	*2.9*			
290-5000		*4.8*	*4.8*	

Dresden Containment Overpressure Credit (psi)				
480-6000	*1.9*			
5000-30000		*~~4.25~~ 5.2*	*~~5.3~~ 5.2*	*Clarify - April 13, 2001 submittal supplement revised to 5.2 psi - however difference column remains 0.8 psi*
6000-end	*2.5*			
30000-end		*NA*	*From 30000 seconds to the end of the accident, the available pressure and require pressure decrease in parallel fashion. Minimum margin between available pressure and required pressure during this period is 2.4 psi.*	*Was this an omission or is no credit being requested? If no credit explain how long term NPSH availability has been achieved; considering the previous need of 2.5 psi and proposed need for 5.2 psi at 5000-30000 seconds.*

Quad Cities Containment Overpressure Credit (psi)				
Time (seconds)	*Current amendment request*	*EPU Requested condition*	*NEDC-32961P Safety Analyses Report*	*Comment*
0-210	*8.0*			
0-290		*9.5*	*8*	*clarify/correct*
210-600	*2.5*			
290-5000		*4.8*	*4.8*	
600-10000	*3.0*			

Quad Cities Containment Overpressure Credit (psi)				
5000-30000		*4.25*	*6.75*	*Clarify/correct*
10000-end	*3.5*			
30000-end		*NA*	*From 30000 seconds to the end of the accident, the available pressure and require pressure decrease in parallel fashion. Minimum margin between available pressure and required pressure during this period is 1.6 psi.*	*Was this an omission or is no credit being requested? If no credit, explain how long term NPSH availability has been achieved; considering the previous need of 3.5 psi and proposed need for 4.25 (6.75) psi at 5000-30000 seconds.*

Response
The inconsistencies between the Reference 3 Power Uprate Safety Analysis Report (PUSAR) Table 4-2 and the license amendment request will be resolved in a revised PUSAR that will be submitted separately.

Question
13. *In many places, the bases for changing a Technical Specification relating to the extended power uprate increased power level is not provided. Selected parameters, such as the revised power level for applicability of the turbine stop valve and turbine control valve fast closure reactor trips (38.5% versus 45% currently) have stayed the same, as measured by thermal power, to maintain the same analyses power level. Selected other changes have been addressed as acceptable at the increased thermal power associated with the existing stated percentage of reactor thermal power (RTP). For example in several places the safety analyses report NEDC-32926P notes that the technical specification surveillance applicability threshold for the rod block monitor remains with a value of 30% RTP. In other places no basis is provided for the 17% increase in requirement resulting from the EPU. For example, TS SR 3.3.1.1.2 to Channel check APRMs above 25 (21.4)% RTP to verify the absolute difference is less than 2 (1.7)% RTP; the feedwater system and main turbine high water level trips required to be operable above 25 (21.4)% RTP; among others. If these changes have been addressed, provide a comprehensive cross reference to the basis for all Technical Specifications which reference RTP. If not, either provide the basis for these changes or propose changes which maintain the existing thermal power for the associated Technical Specification.*

Response

The following table provides a listing of all the DNPS and QCNPS TS references to % rated thermal power (RTP) that are not being proposed for change in Reference 3. The table provides either a basis for the TS value following EPU, or a reference to the PUSAR section that discusses the basis.

TS Reference	Page	RTP	Basis
Safety Limit 2.1.1 (Reactor Core SLs)	2.0-1	≤ 25%	PUSAR Section 9.1 paragraph 8
3.1.3 Condition D (Control Rod Operability)	3.1.3-3	> 10%	PUSAR Section 5.3.12
Surveillance Requirement (SR) 3.1.4.1 (Control Rod Scram Time)	3.1.4-1	40%	See Note 4
SR 3.1.4.4 (Control Rod Scram Time)	3.1.4- 2	40%	See Note 4
LCO 3.1.6 (Rod Pattern Control)	3.1.6-1	≤ 10%	PUSAR Section 5.3.12
Section 3.2 (Power Distribution Limits)	3.2.1-1 thru 3.2.4-1	≥ 25%	PUSAR Section 9.1 paragraph 8
SR 3.3.1.1.2 (APRM Gain)	3.3.1.1-4	≥ 25%	PUSAR Section 9.1 paragraph 8
SR 3.3.2.1.2 (Control Rod Block)	3.3.2.1-4	≤ 10%	PUSAR Section 5.3.12
SR 3.3.2.1.3 (Control Rod Block)	3.3.2.1-4	≤ 10%	PUSAR Section 5.3.12
SR 3.3.2.1.5 (RBM not bypassed)	3.3.2.1-5	≥ 30%	PUSAR Section 9.2.1.2, paragraph 4
SR 3.3.2.1.6 (RWM not bypassed)	3.3.2.1-5	≤ 10%	PUSAR Section 5.3.12
Table 3.3.2.1-1 Note a (RBM)	3.3.2.1-6	≥ 30%	PUSAR Section 9.2.1.2, paragraph 4
Table 3.3.2.1-1 Note b (RWM)	3.3.2.1-6	≤ 10%	PUSAR Section 5.3.12
LCO 3.3.2.2 Applicability and Action C.2 (Feedwater / Main Turbine High Level Trip)	3.3.2.2-1 3.3.2.2-2	25%	PUSAR Section 9.1 paragraph 8
SR 3.4.2.1 (Jet Pumps)	3.4.2-1	> 25%	PUSAR Section 9.1 paragraph 8
Section 3.6.2.1 (Suppression Pool Temp)	3.6.2.1-1 3.6.2.1-2	≤ 1%	See Note 1
Section 3.6.2.5.(Drywell–Suppression DP)	3.6.2.5-1	15%	See Note 2
LCO 3.6.3.1 and Action B.1 (Primary Containment O_2)	3.6.3.1-1	15%	See Note 3
LCO 3.7.7 Applicability and Condition B (Main Turbine Bypass System)	3.7.7-1	≥ 25%	PUSAR Section 9.1 paragraph 8

Notes:

1. According to the bases for Technical Specification (TS) 3.6.2.1, the 1% RTP value is approximately equal to normal system heat losses, such that the reactor is effectively shutdown. This number was based on engineering judgment and would still apply to EPU. It should be noted that the containment analyses which are used to confirm that containment pressure and temperature limits are not exceeded consider reactor thermal powers up to 102% RTP. It is therefore expected that the increase in the RTP with EPU would not result in exceeding the design basis maximum allowable values for primary containment pressure or temperature if an accident or transient event with pool heatup were to occur at 1% RTP. Therefore, the reference to a 1% RTP is retained for TS 3.6.2.1.

2. According to the bases for TS 3.6.2.5, the drywell-to-wetwell pressure difference must be controlled when the primary containment is inert. The 15% RTP value is related to the TS requirements to inert the containment within 24 hours after the reactor is greater than 15% RTP during startup and to de-inert the containment within the last 24 hours prior to reaching 15% RTP during a plant shutdown (see TS 3.6.3.1-1, "Primary Containment O_2"). As stated in the response for TS 3.6.3.1-1 in note 3 below, the current basis and applicability of the ≤15% RTP is valid for EPU with respect to containment inerting requirements.

3. The current basis and applicability of the <15% RTP window for relaxation of the inerting requirement during startup and shutdown is valid for EPU. As described in bases for TS 3.6.3.1, the probability of an event that generates hydrogen during these windows is low.

4. For EPU, the requirement remains unchanged at 40% RTP. This power level is not a critical value and is chosen for convenience. The 40% RTP maximum is above the low power setpoint that allows control rod drives to be withdrawn for scram testing. It also allows scram testing to be performed sufficiently early in the startup mode when the power level is low.

<u>Question</u>
14. Section 6.4.1.1 Safety-related loads for service water system notes that increased heat load imposed on the containment cooling water system is within the existing system capacity following the most demanding design basis event. What is the increase in the heat load for the CCSW system and what is the system capacity?

<u>Response</u>
The containment cooling service water (CCSW) system is used at the DNPS Units 2 and 3 to remove heat from the suppression pool. QCNPS Units 1 and 2 use the residual heat removal service water (RHRSW) system, which serves the same function as the CCSW system at DNPS.

The heat removal rate at design conditions for the DNPS Units 2 and 3 CCSW Systems is 71 MBTU/hr with 165°F suppression pool temperature and 95°F service water temperature. As the suppression pool temperature increases, the heat load (i.e., heat removal rate) will also increase and the heat load will be the maximum at the peak suppression pool temperature. For the pre-EPU power level, an analysis was performed using the same methodology as for the EPU power level. This analysis determined that, for the pre-EPU power level, the peak suppression pool temperature is determined to be 188°F for the limiting design basis event, and the heat load at this suppression pool temperature based on the design system capability is 94 MBTU/hr. At EPU conditions, using the same methodology, the peak suppression pool temperature with the same design system capability increases to 196°F for the same limiting design basis event. The maximum heat load at this peak temperature is 102 MBTU/hr. This means that the EPU results in an increase of 8 MBTU/hr in the maximum heat load for the DNPS Units 2 and 3 CCSW Systems.

The heat removal rate at design conditions for the QCNPS Units 1 and 2 RHR Systems is 66 MBTU/hr with 165°F suppression pool temperature and 95°F service water temperature. For the pre-EPU power level, an analysis was performed using the same methodology as for the EPU power level. This analysis determined that the peak suppression pool temperature is 190°F for the limiting design basis event, and that the heat load at this suppression pool temperature based on the design system capability is 90 MBTU/hr. At EPU conditions, using this same methodology, the peak suppression pool temperature with the same design system capability increases to 199°F, and the heat load at this peak temperature is 98 MBTU/hr. Thus, an increase of 8 MBTU/hr in the maximum heat load occurs for the QCNPS Units 1 and 2 RHR Systems due to EPU.

Since the CCSW and RHRSW systems maintain the suppression pool temperatures at acceptable levels, the increased heat load on these systems is acceptable.

<u>Question</u>
16. Section 6.4.3. The safety analyses report states that reactor building closed cooling water system heat loads do not increase significantly following EPU. Provide the pre- and post- peak EPU heat loads for the shutdown cooling heat exchanger; spent fuel pool heat exchangers; reactor recirculation pumps; the design RBBCW heat removal capability and total peak heat load post-EPU. Include consideration of the limiting single failure or no failure if this is a more limiting case. Also include an evaluation of the maximum heat removal capability of the system.

<u>Response</u>
The pre- and post-EPU heat loads are provided in Tables 16-1 through 16-4. Although several individual heat loads have increased as a result of EPU, the total system heat load has not increased significantly.

Single failure of a component in the RBCCW system is accommodated by a swing heat exchanger and pump shared between the two units at each site.

To maximize the heat load delivered to the RBCCW system, the system was evaluated assuming three RBCCW heat exchangers on-line with three RBCCW pumps, three shutdown cooling heat exchangers on-line for DNPS Units 2 and 3, and two fuel pool heat exchangers on-line for DNPS Units 2 and 3 and QCNPS Units 1 and 2. This is not a normal operating configuration since a full core offload is assumed with an initial reactor coolant temperature of 339°F. The following results were obtained.

<u>DNPS Unit 2</u>

Heat Removed by RBCCW System:	281.2 MBTU/hr
RBCCW Heat Exchanger Cold Temperature:	107.6°F
RBCCW Heat Exchanger Hot Temperature:	133.7°F

<u>DNPS Unit 3</u>

Heat Removed by RBCCW System:	269.6 MBTU/hr
RBCCW Heat Exchanger Cold Temperature:	107.0°F
RBCCW Heat Exchanger Hot Temperature:	132.1°F

<u>QCNPS Units 1 & 2</u>

Heat Removed by RBCCW System:	38.4 MBTU/hr
RBCCW Heat Exchanger Cold Temperature:	104.1°F
RBCCW Heat Exchanger Hot Temperature:	114.0°F

Since the resulting heat exchanger hot temperatures remain acceptable, the evaluation results shown above demonstrate that the RBCCW System is capable of removing the maximum EPU calculated heat loads for each of the modes of operation.

<u>Question</u>

17. Section 6.4.5 addresses the adequacy of the ultimate heat sink (UHS). In the event of downstream dam losses, the water trapped in the intake and discharge bay becomes the UHS for Quad Cities 1&2 and the water trapped in the intake canal becomes the UHS for Dresden 2&3. Considering the increased decay heat associated with the EPU, provide details of the analyses of the available water supply trapped in these UHSs for safe shutdown for all units; addressing conformance with Regulatory Guide 1.27. Include any revised timing of required operator actions to maintain the UHS; if any.

<u>Response</u>

The design basis for the DNPS and QCNPS Cities UHS was established prior to the issuance of Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Power Plants." The design bases for the DNPS and QCNPS UHS are provided in UFSAR Section 9.2.5, "Ultimate Heat Sink," for each plant.

The capability of the UHS for operation at EPU conditions was evaluated within the context of the UHS design bases as stated above. The results are provided as follows.

<u>Dresden UHS Evaluation:</u>

Dresden takes credit for the isolation condenser to bring the reactor temperature to 212°F. For pre-EPU design basis conditions, the amount of water required by each unit to remove decay through the isolation condenser is 2.5 million gallons over a 30 day period. For operation at EPU, 30 days requirements were calculated to be 2.9 million gallons of water per unit, which is below the 6 million gallons of water available.

As a result of the slight increase in the usage of water at EPU conditions, manual actions to place portable pumps to provide make-up water from the river to the UHS would have to be performed sooner, but this is a negligible impact, given the small increase in volume required.

Question

31. The impact of the increased heat load on the spent fuel pool (SFP) cooling is information we need to be able to fully evaluate your request for an extended power uprate for DNPS Units 2 and 3 and Quad Cities Units 1 and 2. The use of the terminology "planned" and "unplanned" has been used by the staff for the review of SFP heat load changes since questions arose in the mid-1990's regarding refueling practices at Millstone Unit 1. A planned offload is the offload of fuel assemblies to the SFP for any expected (or planned) reason. An unplanned offload is the offload of fuel assemblies to the SFP due to an unforeseen condition (e.g., unexpected shutdown that includes an offload). This difference in terminology was made to ensure SFP temperature evaluations accurately reflected actual licensee practices.

Section 6.3.1 of the safety analyses report notes that the EPU increases heat load on the spent fuel pool cooling system; and discusses analysis confirming the capability of the system to maintain adequate fuel pool cooling. Table 6-2 contains design conditions which are unchanged between pre- and post-uprate except using a 24 month fuel cycle for Quad Cities Units 1 and 2. The table additionally notes that the bulk pool temperature is less than 150°F for a full core off-load, with fuel pool with maximum capacity and with shutdown cooling in fuel pool assist mode. Additional staff review of the UFSAR indicates that both DNPS and Quad Cities were using different guidelines for evaluation of SFP cooling than the current staff practice noted above. These methods include evaluations of partial core offloads (normal) and full core offloads (abnormal); and additionally allow cycle-specific analyses of offloads in lieu of the bounding analyses described in the UFSAR. It is not clear to the staff what assumptions were used to support the EPU safety analyses report.

Please submit the results of additional evaluations on the impact of the increased EPU heat load on the SFP and supporting systems. Your evaluation of the spent fuel cooling system should address both the planned and unplanned offload conditions. The staff will accept either (1) bounding or (2) cycle-specific analyses, or both can be used.

Response

The QCNPS and DNPS fuel pool cooling and cleanup system (FPCCS) evaluation includes an assessment of the impact of uprated conditions on system operation, using partial core offloads (i.e., up to approximately 42% of a full core), which are the normal condition and full core offloads, which are the abnormal condition.

The current licensing basis for these plants is described in Updated Final Safety Analysis Report (UFSAR) Section 9.1.3, "Spent Fuel Pool Cooling and Cleanup System," which states that the SFP analyses are performed with the following conditions.

- Partial core offload requires that the fuel pool temperature must remain less than 141°F at DNPS and 140°F at QCNPS, with the single failure of a cooling train.
- Full core offload requires that temperatures remain below 145°F at DNPS and 150°F at QCNPS without assuming a single failure.

Future refueling outages at DNPS and QCNPS are planned for partial core offloads. However, in a discussion between representatives of EGC and members of the NRC regarding this topic on August 2, 2001, the NRC stated that NRC policy for power uprates was to require that licensees demonstrate the capability to accommodate a planned full-core offload with a single failure of a cooling train. Accordingly, if DNPS and QCNPS should plan for a full core offload during future refueling outages, EGC will perform an analysis of the capability of the spent fuel pool cooling system and the spent fuel pool to perform their function assuming a single failure of a cooling train.

The EPU analysis for both QCNPS and DNPS, as discussed below, was performed to bound the various cases analyzed previously in the respective UFSARs. The EPU analysis for both the normal and abnormal conditions considers that the SFP is already filled with fuel assemblies discharged from previous refueling outages (i.e., 2867 bundles) with the exception of one batch offload to be analyzed for the current cycle (i.e. 306 bundles), with room for a full core offload (i.e., 724 bundles). Also, it is assumed that all previous batches of fuel assemblies have been exposed to a 24 month fuel cycle at the power uprated condition. Additional guidelines used for evaluation of SFP cooling are discussed below.

Each of the FPCCS primary system components was evaluated. These are defined as those flow-affected components that affect system operation due to power uprate, such as heat exchangers, pumps, and filter/demineralizers.

The following methodology and acceptance criteria for the SFP temperature have been used for the power uprate evaluation.

Methodology
The decay heat load is calculated for the two bounding scenarios, "normal" condition, and "abnormal" condition, as a function of time. The SFP temperature is calculated as a function of time, considering the following major elements of heat sources and heat sinks.

- Heat load from the fuel bundles discharged from previous refueling outages
- Heat load from the fuel bundles discharged during the current refueling outage
- Cooling by the FPCCS for QCNPS; FPCCS and shutdown cooling (SDC) for DNPS
- Cooling by evaporation from the pool surface

The ANSI/ANS Standard 5.1-1979 with two sigma uncertainty methodology is used to calculate decay heat in the SFP for both QCNPS and DNPS

QCNPS Assumptions and Acceptance Criteria
SFP bulk temperature shall remain at or below 140°F for a "normal" offload into an almost full

pool. For single failure considerations, three pumps and four heat exchangers of FPCCS out of a total of four pumps and four heat exchangers are assumed to be available. Since four trains of fuel pool cooling are available at QCNPS, and since these are adequate to maintain fuel pool temperature, the failure of one pump is considered the bounding single failure. An initial fuel pool temperature of 110°F was used, which is the normal temperature when there is no refueling activity.

SFP bulk temperature shall be at or below 150°F for an "abnormal" off-load (full core) into a "full" pool that contains the batch just offloaded (i.e., 3173 bundles transferred to the spent fuel pool from previous off loads). Single failure need not be assumed, and four trains of FPCCS (four pumps, four heat exchangers) are assumed to be available.

The required makeup flow for the partial core offload is below the existing system capacity of 51 gpm for each unit. When the two SFPs are inter-tied, the makeup flow capacity doubles to 102 gpm, which is greater than the required makeup flow of 78.5 gpm.

DNPS Assumptions and Acceptance Criteria
SFP bulk temperature shall remain at or below 141°F for a "normal" off-load. An initial fuel pool temperature of 110°F was used, which is the normal temperature when there is no refueling activity.

For single failure considerations, only one train of FPCCS (one pump, two heat exchangers) out of the two pumps and two heat exchangers was assumed to be available. One of the three SDC system loops is aligned to the fuel pool in alternate decay heat removal (ADHR) mode. In ADHR mode, this train of SDC is aligned to the SFP and provides cooling to the fuel in both the SFP and the reactor vessel. ADHR mode is initiated only after a cycle specific determination of the time following reactor shutdown at which the heat removal capability of this mode is adequate. In ADHR mode, the single failure of one train of the FPCCS is considered the bounding single failure because, during refueling outages, DNPS retains the ability to line up an additional train of SDC to the fuel pool within eight hours of the loss of the operating SDC train. The management of this SDC availability is governed by DNPS shutdown safety management procedures.

SFP bulk temperature shall be at or below 150°F for an "abnormal" off-load (full core) into a "full" pool that contains the batch just offloaded (i.e., 3173 bundles transferred to the spent fuel pool from previous offloads). Single failure need not be assumed for this case, so this is accomplished with both trains of FPCCS (two pumps, two heat exchangers) and one SDC system loop in fuel pool cooling assist mode.

The required makeup flow of about 30 gpm for the partial core offload case is below the existing system capability of 54 gpm. For the full core offload case the makeup requirement is 70 gpm. There are several fire hoses that are also available to provide makeup water for the full core offload case or for the pool in the event of loss of fuel pool cooling. There are three sources for water: contaminated demineralization system, clean demineralization system and the fire protection system. Each fire hose is capable of delivering over 90 gpm. Therefore the makeup flow is much greater than the 70 gpm water loss calculated due to EPU.

Normal Condition - Batch Offload
A heat sink temperature of 95°F is assumed to be available for cooling the FPCCS heat exchangers (including SDC heat exchanger for DNPS) and the SFP is assumed to be initially at 110°F for these conditions.

The heat load from the previous cycles is based on 2867 bundles in the SFP. These bundles are assumed to consist of ten offloads, the first offload of 113 bundles and nine subsequent offloads, each with 306 bundles. Each batch is discharged at 24 month intervals, having seen 2957 MWt (EPU condition). When added to the 306 offloaded bundles, 3173 cells are loaded for normal condition.

The fuel transfer from the RPV to the SFP is initiated at 100 hours after reactor shutdown and with fuel transfer rate of ten fuel bundles per hour. When the fuel transfer is initiated, the fuel pool gate is assumed to open, and stay open until the end of the fuel transfer. At the end of fuel transfer, the fuel pool gate is assumed to be closed, and the heat load in the RPV is assumed to be cooled by the RHR system (QCNPS) or the SDC system (DNPS). While the fuel pool gate is open, the surface area of the reactor cavity is added for additional evaporation and the water mass in the reactor cavity is also used for additional heat absorption.

With these assumptions, the SFP temperature versus time is calculated, as is the evaporative loss from the pool surface. Assuming all fuel pool cooling is lost for the above batch offload scenario, at the time of peak SFP temperature, the time to reach the boiling point and the boiloff rate is calculated. The acceptance criterion for the SFP temperature is to be at or below 140°F for QCNPS and 141°F for DNPS.

Abnormal Condition - Full Core Offload
The batch offload for normal condition is accomplished following one complete 2-year cycle. Following normal condition, the plant completes another 2-year cycle, and an "emergency" requires that the full core be offloaded into the SFP. This "emergency" scenario defines abnormal condition.

A heat sink temperature of 95°F is assumed for cooling the heat exchangers for FPCCS (and SDC heat exchanger for DNPS).

The fuel transfer from the RPV to the SFP is initiated at 100 hours after reactor shutdown and with fuel transfer rate of ten fuel bundles an hour.

The SFP temperature and the evaporative loss are calculated for this case. Then, assuming all fuel pool cooling is lost for the above core offload scenario at the time of peak SFP temperature, the time before the pool reaches the boiling point is calculated, and the boiloff rate is calculated.

The abnormal condition acceptance criterion for the SFP temperature is to be at or below 150°F.

<u>Results</u>
The results of evaluations on the impact of the increased EPU heat load on the SFP and supporting systems are included in Tables 33-1 and 33-2. These evaluations indicate that the current requirements for SFP temperature can be maintained under EPU conditions.

<u>Question</u>
31.1 Bounding Analysis - Your response for a bounding analysis should include two scenarios planned and unplanned offloads.

A)Planned Offload Calculation - Planned offload is the offload of fuel assemblies to the SFP for any expected (or planned) reason.
Analysis conditions:
1) decay heat load is from spent fuel that is "planned" to be offloaded, either full or partial core plus heat load from an SFP with all other storage locations filled
2) bulk SFP temperature must remain below 150°F
3) worst single active failure, including common cause failures (not just one train)
4) initial conditions highest ultimate heat sink temperature; fouled heat exchangers.
If the resultant temperature is above 150°F, you should perform and submit an analysis to demonstrate that the SFP structure can withstand the new high temperature for long periods of time.

B) Unplanned Offload Calculation - An unplanned offload is the offload of fuel assemblies to the SFP due to an unforeseen condition (e.g., unexpected shutdown that includes an offload).
Analysis conditions:
1) decay heat load is based on a full core offload plus refueling load that has decayed for 36 days plus heat load from an SFP with all other storage locations filled
2) bulk SFP temperature must remain below boiling
3) no single failure needs to be considered

<u>Response</u>
For a discussion of planned and unplanned offloads, see the response to Question 31 above.

Regarding the assumptions used for the emergency offload, the decay heat load is based on a full core offload that has been operating for a full 24 month cycle, plus a refueling load that has decayed for 24 months plus the heat load from the SFP with all other storage locations filled. This bounds the emergency offload after 36 days of operation as described below. The maximum peak decay heat load for a full core offload into the SFP (completed 173 hours after shutdown) is 37.8 MBTU/hr after 36 days of operation and 37.9 MBTU/hr after 2 years of operation.

<u>Question</u>
31.2 Cycle-specific Analysis - You can alternately opt to perform a calculation prior to every planned offload using the actual conditions at the time of the offload. The wait time for offload can be adjusted, as long as the time is not shorter than what is assumed for the fuel handling accident. For unplanned offload, you can either commit to performing the same calculation prior

to offload or have a bounding calculation for unplanned offloads only, using the same guidelines as in Section 31.1 B) above.
Cycle-specific analysis conditions
1) decay heat load based on actual number of fuel assemblies planned to be offloaded plus heat load from actual assemblies in the previously loaded into pool
2) use actual system conditions ultimate heat sink temperature; heat exchanger fouling
3) worse active single failure, including common cause failures (not just one train)
4) bulk SFP temperature must remain below 150°F
5) include temporary modifications, if any

Response
The calculations performed for EPU are expected to be bounding for partial core offloads. As discussed in the response to Question 31 above, if DNPS and QCNPS should plan for a full core offload during future refueling outages, EGC will perform an analysis of the capability of the spent fuel pool cooling system and the spent fuel pool to perform their function assuming a single failure of a cooling train.

The calculations performed for EPU are expected to be bounding for unplanned offloads.

Question
32. Ability to supply adequate make-up source in event of loss of SFP cooling
Considering any analyses changes, re-confirm time to boil-off is sufficient to allow mitigative actions and the make up water required is within the system capacity in case of a complete loss of cooling to the SFP. Provide time to boil-off and boil-off rate.

Response
Time to boil and boil-off rates are given in the attached Tables 31-1 and 31-2. The makeup water capability is discussed in the response to Question 31.

Question
33. Section 4.7 on post-LOCA combustible gas control notes margin changes in various parameters associated with the EPU and additional impact of GE14 fuel introduction on metal-water hydrogen production. The 5% oxygen limit is reached in 19 hours, versus 25 hours pre-EPU. The minimum stored volume of nitrogen to maintain containment atmosphere below the 5% flammability limit for seven days will be 141,000 scf following EPU. Considering the increased nitrogen storage requirement and the reduced time to reach oxygen flammability concentrations following a design basis accident, address why technical specifications should not be added for the operability and surveillance of the containment atmosphere dilution system, including nitrogen storage (Reference BWR/4 STS 3.6.3.4, in accordance with 10 CFR 50.36(c)(2)(ii) criterion 3 - A system that is part of the primary success path and which functions to mitigate a design basis accident that presents a challenge to the integrity of a fission product barrier).

Response

The DNPS and QCNPS TS were recently revised to reflect the BWR Improved Standard Technical Specifications as noted in Reference 6. NUREG-1433, Specification 3.6.3.4, "Containment Atmosphere Dilution (CAD) System," was not included in the DNPS and QCNPS Improved Technical Specifications since the current licensing basis did not include requirements for a CAD system. In Reference 7, the NRC approved the deletion of the technical specification (TS) requirement for the primary containment nitrogen system based upon relocating these requirements to the UFSAR. The nitrogen system supports the requirements for primary containment oxygen concentration specified in TS 3.6.3.1. The nitrogen system also performs the CAD system function to maintain post-accident combustible gas concentrations within the primary containment at or below the flammability limits by purging the containment atmosphere with nitrogen. Since the NRC had previously determined that licensee controlled procedures and administrative controls were adequate to ensure nitrogen system operability, no new TS requirements associated with the EPU were deemed to be necessary. The nitrogen system continues to maintain the containment in an inerted condition as required by TS 3.6.3.1 and remain capable of purging the containment with nitrogen as necessary under accident conditions. Therefore, consistent with the current licensing basis, CAD requirements are not included in the TS for EPU.

Table 16-1
Pre-EPU RBCCW System Heat Loads (x 10^6 BTU/HR) – DNPS Unit 2 or 3

SERVICE	Mode of Service				
	Normal Operation	Cooldown	Shutdown (> 48 hrs)	Startup	A.C Power Failure
Reactor Recirculation Pump and Motors	0.9	0.9	0.5	0.9	0.9
Fuel Pool Coolers	7.3	7.3	7.3	7.3	-
Shutdown Heat Exchanger	-	90	48.5	-	-

Post-EPU RBCCW System Heat Loads (x 10^6 BTU/HR) – DNPS Unit 2 or 3

SERVICE	Mode of Service				
	Normal Operation	Cooldown	Shutdown (> 48 hrs)	Startup	A.C Power Failure
Reactor Recirculation Pump and Motors	1.01	1.01	0.56	1.01	1.01
Fuel Pool Coolers	13[(1)]	13[(1)]	17[(2)]	13[(1)]	-
Shutdown Heat Exchanger	-	374.1[(3)]	48.5	-	-

Footnotes:
(1) At 17 days, heat load is 13 x 10^6 BTU/hr
(2) For emergency, full core offload, heat load will be 39.0 x 10^6 BTU/hr. However, the shutdown heat exchanger heat load will be 0 BTU/hr. (At 6 days, heat load is 17 x 10^6 BTU/hr)
(3) For commercial reasons, it is desirable to cool down the reactor within 24 hours for a refueling outage. The ability of the RBCCW system to achieve refueling temperature (140°F) within 24 hours was evaluated as part of the EPU evaluation. For this operating mode, an initial heat transfer from the shutdown heat exchangers of 374.1 x 10^6 BTU/hr and a total system heat transfer rate of 435.78 x 10^6 BTU/hr will be required. Although the design heat transfer rate with two RBCCW heat exchangers is 156 x 10^6 BTU/hr, and the design heat transfer rate with three RBCCW heat exchangers is 234 x 10^6 BTU/hr, the required heat transfer rate of 435.78 x 10^6 BTU/hr can be achieved at service water temperatures below the design value of 95°F. There are no safety concerns associated with achieving shutdown within 24 hours, so if the service water temperature is too high or if only two RBCCW heat exchangers are used, it will simply take longer to achieve cold shutdown.

Table 16-2
Pre-EPU RBCCW System Heat Loads (x 10^6 BTU/HR) – QCNPS Unit 1 or 2

SERVICE	Mode of Service				
	Normal Operation	Cooldown	Shutdown (> 48 hrs)	Startup	A.C Power Failure
Fuel Pool Coolers	8.8	8.8	8.8	8.8	-
Reactor Recirculation Pump and Motors	0.9	0.5	-	0.5	0.5

Post-EPU RBCCW System Heat Loads (x 10^6 BTU/HR) – QCNPS Unit 1 or 2

SERVICE	Mode of Service				
	Normal Operation	Cooldown	Shutdown (> 48 hrs)	Startup	A.C Power Failure
Fuel Pool Coolers	18[(1)]	18[(1)]	45[(2)]	18[(1)]	-
Reactor Recirculation Pump and Motors	1.01	1.01	-	1.01	1.01

Footnotes:

(1) For normal refueling, at 17 days heat load is 18 x 10^6 BTU/hr.
(2) For emergency, full core offload, heat load will be 45.0 x 10^6 BTU/hr. at 7.1 days after shutdown. (At 17 days, heat load is 35 x 10^6 BTU/hr.)

Table 16-3
Total System Heat Loads Cooled By RBCCW
DNPS Total RBCCW System Heat Loads (x 10^6 BTU/HR)

SERVICE	Mode of Service				
	Normal Operation	Cooldown	Shutdown (> 48 hrs)	Startup	A.C Power Failure
Heat removal rate at original design conditions	156	234[3]	156	156	78
Pre-EPU heat removal rate (DNPS Unit 2)	61.04	145.87	69.65	54.87	5.4
Post-EPU heat removal rate (DNPS Unit 2[1])	66.85	435.78[2]	79.41	60.68	5.51

Footnotes:

(1) Heat loads at DNPS Unit 2 are most conservative
(2) For commercial reasons, it is desirable to cool down the reactor within 24 hours for a refueling outage. The ability of the RBCCW system to achieve refueling temperature (140°F) within 24 hours was evaluated as part of the EPU evaluation. For this operating mode, an initial heat transfer from the shutdown heat exchangers of 374.1 x 10^6 BTU/hr and a total system heat transfer rate of 435.78 x 10^6 BTU/hr will be required. Although the design heat transfer rate with two RBCCW heat exchangers is 156 x 10^6 BTU/hr, and the design heat transfer rate with three RBCCW heat exchangers is 234 x 10^6 BTU/hr, the required heat transfer rate of 435.78 x 10^6 BTU/hr can be achieved at service water temperatures below the design value of 95°F. There are no safety concerns associated with achieving shutdown within 24 hours, so if the service water temperature is too high or if only two RBCCW heat exchangers are used, it will simply take longer to achieve cold shutdown. The heat removal rate required to reach the TS cold shutdown temperature of 212°F is within the capability of the system.
(3) The third RBCCW heat exchanger is used during cooldown, to minimize outage time for refueling.

Table 16-4
QCNPS Total RBCCW System Heat Loads (x 10^6 BTU/HR)

SERVICE	Mode of Service				
	Normal Operation	Cooldown	Shutdown (> 48 hrs)	Startup	A.C Power Failure
Heat removal rate at original design conditions	27.64 (3)	27.64 (3)	41.46 (1) (3)	27.64 (3)	13.82 (3)
Pre-EPU heat removal rate	29.64	29.24	13.89	29.24	5.30
Post-EPU heat removal rate	38.95 (2)	38.95 (2)	50.09 (2)	38.95 (2)	5.81

Footnotes:

(1) The third RBCCW heat exchanger is used during emergency full core off-load.
(2) The heat exchangers are able to dissipate the higher heat loads without exceeding the current design basis cold RBCCW temperature of 105°F, based on a new maximum service water temperature of 90°F. The original design service water temperature from manufacturer data sheets was 95°F, but operating experience has shown that service water temperatures have never exceeded 90°F in the history of operation of QCNPS. It is concluded that with two RBCCW heat exchangers aligned to each QCNPS Unit and a maximum service water temperature of 90°F, the cold RBCCW temperature will not exceed 104°F for all operating modes except the emergency full core offload event. For the emergency full core offload event, the swing heat exchanger will need to be aligned to the unit with the emergency full core offload. All other operating parameters of the RBCCW system (flows, pressures, temperatures) will remain the same as before EPU.
(3) RBCCW heat exchanger design heat transfer values are based on manufacturer data sheets using 95°F as the inlet service water temperature. The design basis maximum service water temperature has been changed to 90°F, which results in heat transfer capability exceeding required load for all operating modes.

TABLE 31-1
QCNPS SPENT FUEL POOL DECAY HEAT LOAD PARAMETERS

SFP Case	Peak Heat Loads	Time to Boil[1] (from peak pool temperature)	Boiloff Rate at 212°F	Peak SFP Temperature with FPCCS	Remarks
Normal Condition: Batch offload of 306 bundles 100 hours after shutdown	22.3×10^6 BTU/hr	40 hrs	43 gpm	128°F at 157 hours after shutdown	Pool almost full (2867 cells filled) with uprate bundles. SFP contains 3173 bundles after offload. Three FPCCS pumps and four heat exchangers operating.
Abnormal Condition: batch offload of 724 bundles 100 hours after shutdown	44.3×10^6 BTU/hr	13.5 hours	78.5 gpm	150°F at 190 hours after shutdown	Pool almost full (3173 cells filled) with uprate bundles. SFP contains 3897 bundles after offload. Four FPCCS pumps and heat exchangers operating. Two years of operation after above batch offload. QCNPS has 102 gpm makeup water capability from two units.

(1) To 211°F

TABLE 31-2
DNPS SPENT FUEL POOL DECAY HEAT LOAD PARAMETERS

SFP Case	Peak Heat Loads	Time to Boil (from peak pool Temperature)	Boiloff Rate at 212°F	Peak SFP Temperature with FPCCS	Remarks
Normal Condition: Batch offload of 306 bundles 100 hours after shutdown	17.4×10^6 BTU/hr	29 hours	30 gpm	125°F at 146 hours after shutdown	Pool almost full (2867 cells filled) with uprate bundles. SFP contains 3173 bundles after offload. One FPCCS pump and two heat exchangers and SDC in FPC assist mode operating.
Abnormal Condition: Batch offload of 724 bundles 100 hours after shutdown	39.1×10^6 BTU/hr	8 hours	70 gpm	150°F at 183 hours after shutdown	Pool almost full (3173 cells filled) w/ uprate bundles. SFP contains 3897 bundles after offload. Two FPCCS pumps and heat exchangers operating along with one SDC at 1500 gpm. Two years of operation after above batch offload.

Attachment C
Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation (Non-Proprietary)
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

<u>References</u>

1. Letter from K. A. Ainger (Exelon Generation Company, LLC) to U. S. NRC, "Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station," dated August 7, 2001

2. Letter from U. S. NRC to I. Johnson (Commonwealth Edison Company), "Issuance of Amendments," dated April 30, 1997

3. Letter from R. M. Krich (Commonwealth Edison Company) to U. S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000

4. Letter from J. P. Dimmette, Jr. (Commonwealth Edison Company) to U.S. NRC, "Request for License Amendment Pursuant to 10 CFR 50.90 Credit for Overpressure," dated January 29, 1999

5. Letter from U. S. NRC to O. D. Kingsley (Commonwealth Edison Company), "Quad Cities – Contractor Review of Head Loss Calculations Associated with Request for License Amendment," dated September 8, 2000

6. Letter from U. S. NRC to O. D. Kingsley (Exelon Generation Company, LLC), "Issuance of Amendments", dated March 30, 2001

7. U. S. NRC, "Safety Evaluation By The Office Of Nuclear Reactor Regulation Related to Amendment No. 150 to Facility Operating License No. DPR-19, Amendment No. 145 to Facility Operating License No. DPR-25, Amendment No. 171 to Facility Operating License No. DPR-29, and Amendment No. 167 to Facility Operating License No. DPR-30, Commonwealth Edison Company and MidAmerican Energy Company," dated June 28, 1996