10 CFR 50.59
10 CFR 50.90
10 CFR 50.30(b)

Boston Edison

Pilgrim Nuclear Power Station
Rocky Hill Road
Plymouth, Massachusetts 02360

L. J. Olivier
Vice President Nuclear Operations
and Statinn Director

May 14, 1997
BECo Ltr. 2.97.035

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

Docket No. 50-293
License No. DPR-35

Response to Request for Additional Information Concerning Pilgrim Station Crediting Containment Overpressure in the Net Positive Suction Head Analysis for the Emergency Core Cooling Pumps (TAC No. M97789)

References:

1) Boston Edison Letter (BECo letter No. 97.004) to NRC dated January 20, 1997, entitled "Request for Review"
2) Boston Edison Letter (BECo letter No. 97.008) to NRC dated January 30, 1997, entitled "Significant Hazards Evaluation for Pilgrim Nuclear Power Station's Net Positive Suction Head Analyses"
3) Boston Edison Letter (BECo letter No. 97.023) to NRC dated February 27, 1997, entitled "Supplemental Submittal on Pilgrim Station NPSH Analysis"
4) Boston Edison Letter (BECo letter No. 97.042) to NRC dated April 11, 1997, entitled "Revised Request for License Amendment to Credit Containment Pressure in ECCS NPSH LOCA Analyses"
5) Safety Evaluation 2971
6) Safety Evaluation 2983
7) Calculation M662
8) GE Report GE-NE-B13-0185-11
9) NRC Request for Additional Information (RAI) dated March 13, 1997
10) NRC Request for Additional Information (RAI) dated March 31, 1997
11) NRC Request for Additional Information (RAI) dated April 17, 1997

By references 1 through 3, Boston Edison Company (BECo) requested NRC review and approval of a license amendment under 10 CFR 50.90 to credit containment pressure as a component of net positive suction head (NPSH) margin in the PNPS licensing basis. To aid in that review, reference 1 included submittal of NPSH and safety analyses based on the site maximum ultimate heat sink (UHS) temperature (References 5 through 8).

References 9 through 11 requested additional information (RAI) on these submittals. Boston Edison's response to all RAI questions in references 9 through 11 is provided in Attachments 1 through 4 of this letter. Attachment 6 to this letter is a copy of Boston Edison emergency diesel loading calculation (PS-79) submitted at the verbal request of the NRC Project Manager, Mr. Alan Wang.

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Reference 4 informed the NRC staff that BECo had resolved, by increasing the size of the low pressure ECCS pump suction strainers, the unreviewed safety question (USQ) regarding Pilgrim's use of containment pressure higher than atmospheric to evaluate ECCS pump NPSH for the current licensing basis debris-related head loss. However, this resolution was based on an ultimate heat sink temperature limit of 65°F, and reference 4 contained a commitment by BECo to enter the Technical Specification containment cooling limiting condition of operation (LCO) that requires the plant be in cold shutdown within 24 hours if the UHS temperature exceeds 65°F. Pilgrim is currently operating well under this UHS temperature limit, but we forecast with 95% confidence, based on past inlet temperature data, that this UHS temperature limit will be exceeded sometime after the third week of June. Therefore, it is expected that the requested license amendment will be required to allow the continued operation of Pilgrim Station during the summer.

The submittal for the subject license amendment includes an analysis for Pilgrim operation up to a UHS temperature of 75°F, which requires containment pressure higher than atmospheric to meet low pressure ECCS pump NPSH requirements. Specifically, BECo requested that the NRC approve the analysis described in FSAR section 14.5.3.1.3 and illustrated on FSAR Figures 14.5-9 through 10, Figure 14.5-13, and Figures 14.5-18 through 19. The following request supplements the request described above which was communicated in reference 1. Specifically, BECo requests approval to credit the following levels of containment pressure when evaluating ECCS pump NPSH:

Time After Accident	Containment Pressure (psig)
0 to 600 sec.	0
600 to 6000 sec	1.9
6000 sec. to 5 days	2.5

The basis for this specific request is provided in the answer to question 6 in Attachment 2 (corresponding to questions 11 through 16 from Enclosure 2 to the March 13, 1997, NRC RAI).

The clarifying information provided with this letter does not change the no significant hazard consideration determination submitted by reference 2.

This letter contains the following commitments:

- General Electric Report GE-NE-T23-00732-01 will be submitted under separate cover due to its proprietary status.
- Pilgrim will submit a change to its Technical Specifications by the end of the first quarter of 1998 that makes local pool temperature surveillance requirements consistent with the Technical Specification bases proposed in SE2983.
- Pilgrim will submit an ultimate heat sink temperature limit Technical Specification by the end of the first quarter of 1998.
- Pilgrim will complete a revised containment analysis using a decay heat input based on ANS 5.1-1979 including two standard deviations (2σ) added to the fission product decay heat.

Attachment 5 to this letter lists the user defined variables required by ANS 5.1-1979 to calculate the decay heat and standard deviation. BECo plans to utilize the values listed on Attachment 5 for the analysis performed to meet this commitment. Please note that the listed values are different from those used to develop the decay heat curve used in the analysis submitted for this amendment in references 5 through 8; however, the new inputs for the ANS 5.1-1979 user defined variables were selected based on higher fuel enrichments and higher exposures that could be utilized in the future.

This revised analysis will be comprised of the design basis accident events that result in the worst containment conditions (pressure and temperature) and a minimum containment pressure analysis for evaluation of ECCS pump NPSH. Due to the cost of performing this reanalysis, BECo requests the NRC review and approve the decay heat analysis inputs selected for this analysis.

During RFO #11 the drywell spray flowrate was increased to a minimum design value of 1250 gpm from it's previous design value of 720 gpm. This increase in the drywell spray flowrate of greater than 70% will completely offset the drywell temperature increase that would otherwise result from the ANS 5.1-1979 + 2σ decay heat and provide a lower drywell temperature response profile than that currently used for equipment qualification. This plant modification is further discussed in the response to question 1a on Attachment 3.

This analysis will be completed within 180 days of approval of this amendment. The revised analysis will be submitted to the NRC for review and approval upon its completion.

Should you need further information on this issue, please contact P. M. Kahler at (508) 830-7939.

L. J. Olivier

L. J. Olivier

LJO/PJD/avf/npsh-rai

Commonwealth of Massachusetts)
County of Plymouth)

Then personally appeared before me, L. J. Olivier, who being duly sworn, did state that he is Vice President Nuclear Operations and Station Director of Boston Edison Company and that he is duly authorized to execute and file the submittal contained herein in the name and on behalf of Boston Edison Company and that the statements in said submittal are true to the best of his knowledge and belief.

My commission expires: Sept 20, 2002 DATE

Peter M Kahler NOTARY PUBLIC

Attachments:

1) Response to NRC Request for Additional Information (RAI) dated March 13, 1997 (Enclosure 1, questions 1 through 11, Enclosure 2, questions 1 through 10, and Enclosure 3, question 1)
2) Response to NRC Request for Additional Information (RAI) dated March 13, 1997 (Enclosure 2, questions 11 through 16)
3) Response to NRC Request for Additional Information (RAI) dated March 31, 1997 (Enclosure questions 1 through 11)
4) Response to NRC Request for Additional Information (RAI) dated April 17, 1997 (Enclosure questions 1 through 3)
5) User Defined Inputs for ANS 5.1-1979 Decay Heat - Reanalysis Using 2σ Uncertainty
6) Pilgrim Calculation No. PS-79, Revision 4

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Attachment 1

Response to NRC Request for Additional Information (RAI) dated March 13, 1997 (Enclosure 1, questions 1 through 11, Enclosure 2, questions 1 through 10, and Enclosure 3, question 1)

RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION (RAI) DATED MARCH 13, 1997 (ENCLOSURE 1, QUESTIONS 1 THROUGH 11)

Question 1:

By letter dated January 20, 1997, Boston Edison Company (BECo) submitted a request for NRC review. The BECo letter states that "there is a question, from a licensing standpoint, whether credit for containment pressure as part of the NPSH calculation can be taken under the 10CFR50.59 process or whether NRC review is needed..... we are requesting NRC review and approval of this issue prior to March 15, 1997." Additionally, the letter requests "NRC review and approval of the wording currently in FSAR rev. 19 section 15.3.1.3." Credit for containment overpressure can be taken as part of the NPSH calculation if the credited overpressure is specified in the plant's licensing basis. The staff contends that Pilgrim's current licensing basis is that no containment overpressure is required for adequate NPSH of the ECCS pumps with clean strainers. With the changeout of insulation in 1984, BECo cannot assume that their ECCS strainers will be clean following a design basis LOCA; therefore, Pilgrim is outside its current licensing basis. BECo should be proposing a licensing basis change in order to resolve the USQ regarding containment overpressure and debris laden ECCS strainers. Alternatively, submit information including pump manufacturer's test data or other test data to demonstrate that the performance of the ECCS pumps while cavitating (i.e., with inadequate NPSH) would be adequate to fulfill their safety functions for the limiting accident conditions.

Answer:

When the request for a review was submitted to the NRC, Boston Edison Company (BECo) had already concluded credit for containment overpresssure could be taken without incurring an unreviewed safety question (USQ). The original Final Safety Analysis Report (FSAR) defined NPSH margin using a method that is the principal basis for BECo safety evaluation SE 2971 which was prepared in accordance with the requirements of 10CFR50.59. Based on the conclusions and underlying analysis presented in SE 2971, the Updated Final Safety Analysis Report (UFSAR) was changed in accordance with 10CFR50.34(b), specifically the section numbered 14.5.3.1.3 titled "Core Standby Cooling System Pump Net Positive Suction Head". BECo was aware of the NRC concern that Pilgrim's current licensing basis does not specifically credit containment pressure for adequate NPSH of the ECCS pumps with clean or debris laden strainers. BECo, therefore, proposed a licensing basis change to credit containment pressure in calculating pump net positive suction head. Subsequently, the NRC reported its conclusion that operation in a condition that would require the need to credit positive containment pressure to meet NPSH requirements constitutes a USQ.

Question 2:

> *Page 17 of SE 2983 states that the UHS temperature selected for the design rating of safety-related heat removal systems and equipment is 65°F whereas the UHS temperature for the design rating of the main heat sink and associated equipment required for power generation is 75°F. This implies the safety-related heat removal systems and equipment are not designed to perform their intended function during the warmer summer months. Furthermore, a result of the in-depth analysis of the ultimate heat sink temperature indicated that the 75°F salt service water (SSW) inlet temperature could be exceeded on occasion for a limited amount of time. If 75°F is an upper-bound for the UHS, provide an explanation as to why the safety-related heat removal systems are not designed for the upper-bound temperature. Also, page 2 of SE 2983 states that the 75°F SSW injection temperature analysis will supplement rather than replace the current analysis. The staff believes that the uppor-bound 75°F temperature should replace the current 65°F analysis. Provide justification for supplementing the current 65°F analysis rather than replacing it.*

Answer:

During the summer months, seawater temperature at Pilgrim Nuclear Power Station (PNPS) occasionally exceeds 65°F as was noted in the original FSAR. The basis is contained in UFSAR Section 2.4.2 which indicates 65°F is expected to bound the monthly mean of all seawater temperatures recorded in Cape Cod Bay in the month of August. This conclusion was based on temperature data collected during a 32 year period (August having the highest mean seawater temperatures in the PNPS vicinity). This method was used to derive the PNPS design seawater temperature value. Both method and design value as presented in UFSAR Sections 2.4, 4.8, 10.5 and 10.7 were reviewed and approved by the AEC during original plant licensing along with the fact that maximum seawater temperature had at times reached 75°F. In fact, the original FSAR section 2.4.2.3.1 states that the maximum seawater temperature in Boston is 75°F , while Cape Cod Canal is slightly cooler with a maximum of 74°F during the summer. This leads to the conclusion that the PNPS design seawater temperature value for accident analyses was viewed as a risk-averaged value (i.e., 65°F was appropriate for design purposes recognizing this value could be exceeded at certain times during the summer). The design seawater temperature for normal plant operation was 75°F, which was applied to the reactor and turbine building heat exchangers for their normal power operation modes.

The PNPS design seawater temperature value of 65°F was used as an input to the accident analyses (FSAR Section 14.5) which also was reviewed and approved during original plant licensing. Emergency cooling systems for decay heat removal and equipment cooling were rated for accident events using a seawater temperature of 65°F, while the same equipment was rated for 75°F during normal operation.

Use of nominal design values is often considered acceptable when used in conjunction with low probability events. This point is evident in the AEC SER for the PNPS Operating License which states:

> *" We have reviewed... characteristics of the site including meteorology and hydrology to determine that these characteristics had been determined adequately and had been given appropriate consideration in the plant design, and that the site characteristics were in accordance with the Commission's siting criteria (10CFR Part 100) taking into consideration the design of the facility including engineered safety features provided."*

The risk-averaged approach used to establish the design is not unique since this same logic was used to determine the PNPS allowable outage times contained in the Technical Specifications where it is recognized that accidents and single failures are unlikely coincident with a limiting condition of operation.

The risk-averaged approach is reasonable since PNPS is an ocean sited plant as opposed to a river, lake, or estuarial location. As such, the PNPS ultimate heat sink is subject to far greater diurnal and tidal temperature variation. This logically leads to the approved method of selecting a design value based on mean temperature. It should also be kept in mind that the PNPS license predates development of the NRC Standard Review Plans (SRP).

With regard to the decision to supplement rather than replace the 65°F analyses, the ultimate heat sink temperature remains below 65°F the vast majority of the time at PNPS, and the results from the 65°F analyses more closely reflect most operational situations. The decision was made to retain all of that information in the UFSAR and licensing basis for use in evaluating conditions that may present themselves in the future. However, when new designs, repairs or replacements are implemented, the maximum ultimate heat sink temperature will be used if the activity is dependent on the ultimate heat sink temperature as a parameter or input to the design. By utilizing the maximum ultimate heat sink temperature for design purposes, plant operation will not be limited so long as the ultimate heat sink temperature remains at or below 75°F .

Question 3:

> *Pilgrim does not have a TS limit on the UHS temperature, and thus no LCO actions need to be taken if the UHS temperature exceeds the safety-related heat removal systems design rating (65°F) or the main heat sink design rating (75°F). Describe Pilgrim's current procedures that are in place for UHS temperatures greater than 65°F and 75°F. Has Pilgrim considered adopting a technical specification limit on UHS temperature?*

Answer:

Based on the interim safety evaluation (SE3088) submitted April 11, 1997, prior to startup from RFO # 11, BECo informed the NRC that the USQ on crediting containment pressure for NPSH had been resolved by increasing the size of the low pressure ECCS pump suction strainers. However, this resolution was based on an ultimate heat sink (UHS) temperature limit of 65°F, and BECo committed to enter the Technical Specification containment cooling limiting condition of operation (LCO) that requires the plant be in cold shutdown within 24 hours if the

UHS temperature exceeds 65°F. Upon NRC approval of this license amendment, the administrative limit will be raised to 75°F. The UHS temperature administrative limit is implemented by continuous monitoring of the seawater temperature at the inlet of both reactor building closed cooling water (RBCCW) system heat exchangers with an accompanying alarm that will sound in the control room if prescribed limits are exceeded.

The alarm set point is set low enough to allow detection of an increasing inlet temperature before the administrative limit is exceeded. Procedures require frequent trending of inlet temperature and tide level after an alarm is received, investigation into the cause of the alarm (e.g., high temperature, instrument trouble, backwash), discontinuance of any activities (as necessary) to avoid exceeding the administrative limit on inlet temperature (e.g., backwash), and declaration of containment cooling system inoperability when the administrative limit is exceeded. This administrative limiting condition for operation is exited when temperature is declining and below the administrative limit. Furthermore, BECo plans to submit a Technical Specification ultimate heat sink temperature limit no later than the first calendar quarter of 1998 as part of the conversion to Standard Technical Specifications.

Question 4:

> *Page 20 discusses removing the reference to local pool temperature limits and the reference to the associated 160°F bulk suppression pool temperature limit from Technical Specification Bases 3/4.7.A. However, TS Surveillance Requirements 3/4.7.A.c still references the 160°F bulk suppression pool temperature. Will a TS amendment be requested to make the TS surveillance requirements consistent with the TS bases?*

Answer:

BECo plans to submit a Technical Specification change to the suppression pool temperature surveillance requirements prior to changing the associated bases.

Question 5:

> *Page 21 of SE 2983 states that the Chapter 14 design basis LOCA analysis based on a 65°F SSW inlet temperature assumed that at 600 seconds, one RHR pump is shutoff and the RHR loop is placed in suppression pool cooling (with or without spray). However, the design basis LOCA analysis performed using a 75°F SSW inlet temperature assumed that at 600 seconds, LPCI with heat rejection mode, with two RHR pumps in operation is placed in service and the heat exchanger bypass valve in its full open normal position. This continues until two hours post-LOCA when transition to LPCI with heat removal using one RHR occurs. Based on this description, the 75°F design basis LOCA is more limiting than the 65°F design basis LOCA. Do the Emergency Operating Procedures accommodate the differences in pump operation for the two SSW temperature cases?*

Answer:

The current EOP's at PNPS are based on EPG Rev. 4 which prioritize core cooling over containment cooling when reactor water level is less than top-of-active-fuel (TAF) and containment limits are not threatened. This protocol represents a change from that used in original licensing containment analysis which assumes containment cooling commencement 10 minutes after the accident regardless of the indicated reactor water level.

Assumptions made in the original licensing containment analysis with regard to pump sequencing were predicated on achieving adequate core cooling before 10 minutes, removal of the RHR system pumps from the LPCI mode, and the start of containment cooling at 10 minutes. The reactor vessel arrangement, jet pump height, core spray pump flow capability, and level instrumentation are designed to provide two-thirds core coverage and indication of two-thirds core coverage after the design basis accident. The original licensing containment cooling analysis assumed that after 10 minutes no RHR pumps were required for core cooling, and therefore, the system was removed from LPCI mode. The analysis assumed a single core spray pump would continue to operate and maintain two-thirds core coverage. The RHR system was transferred to containment cooling and spray could be used if containment conditions threatened the containment pressure or temperature limits. The reactor water level instruments variable leg is tapped into the base of the jet pump and will indicate at least two-thirds core coverage when the reactor annulus is drained and one core spray pump is operating. After a DBA LOCA, indicated level will be less than TAF conditions and somewhat above two-thirds core coverage.

Removal of RHR pumps from core cooling (i.e., LPCI mode) when reactor water level is below the normal range is a significant operational step, more so in a situation where the containment limits are not challenged and indicated level is less than TAF. Adherence to the EOPs would result in operators staying in the LPCI mode with all available RHR pumps plus Core Spray. After 10 minutes, it is assumed that cooling water is applied to the RHR heat exchanger and the LPCI with Heat Rejection mode is entered. Recognizing the difficulty of deciding when to shutoff one RHR pump to maximize heat transfer, Boston Edison Company chose to delay the transition until two hours after the event and to maintain a minimum of two ECCS pumps in the injection mode throughout the accident response. The assumptions made in the 75°F design basis LOCA analysis with regard to pump sequencing are superior to those in the original licensing basis analysis, since they more accurately reflect the expected response to the event.

The following approach was used by Boston Edison Company to evaluate the spectrum of pipe breaks with an UHS temperature of 75°F.

Containment cooling is initiated after reactor vessel level is stabilized, meaning reflood is complete. The mode of containment cooling used in analysis and the assumed time of containment cooling initiation differ depending on the type of line break. The symptom used to direct the containment cooling method is reactor water level. The following table outlines the approach used in the containment analysis which is consistent with EOP's. For liquid line breaks where indicated level is less than TAF, EOP-01 "RPV Control" instructions would direct

the operators to use available makeup systems to recover indicated level above TAF and to provide maximum cooling to LPCI flow. Coincident with this instruction, EOP-03 "Primary Containment Control" directs operators to commence containment cooling but not at the expense of core cooling. The symptom which is relied on to alert operators to the need to initiate containment cooling is suppression pool temperature greater than 80°F which is an EOP-03 "Containment Control" entry condition. The suppression pool temperature is exceeded almost immediately after the event occurs because the initial pool temperature is assumed to equal the Technical Specification 3.7.A.1.a maximum allowable of 80°F.

The LPCI with Heat Rejection mode as utilized in the 75°F design basis LOCA analysis provides core and containment cooling consistent with the EOP's.

Break Type	Expected Sustainable Reactor Water Level After Reflood	Initiation Time(s)	Containment Cooling Mode
Liquid Line Breaks	$^2/_3$ < Indicated < TAF Level	10 minutes	LPCI with Heat Rejection [2 pumps, heat exchanger bypass valve full open]
		2 hours	LPCI with Heat Rejection [1 pump, heat exchanger bypass valve full closed]
Steam Line Breaks	Indicated Level > TAF	10 min.	Suppression Pool Cooling
		30 min.	Containment Spray

<u>Steam Line Breaks</u>

All postulated steam line breaks are in piping that penetrate the reactor vessel above the TAF. After reflood has restored indicated vessel level to the normal range, a single core spray pump is capable of maintaining vessel level, and RHR pumps operating in LPCI mode are not needed for core cooling. Therefore, it is reasonable to assume that at 10 minutes, the RHR system is entirely dedicated to containment cooling via the suppression pool cooling and/or containment spray mode. Since containment spray is required for steam line breaks to prevent the drywell shell from exceeding the design temperature of 281°F, it is the mode of containment cooling used in steam line break analysis. Rated flow through the RHR heat exchanger is assumed upon commencement of containment cooling.

<u>Liquid Line Breaks</u>

All but the smallest liquid line break sizes are sufficiently large that the break flow from the downcomer region of the vessel exceeds makeup capability, and the downcomer region of the vessel will drain below the top of the jet pump. With downcomer level below the top of the jet pump, indicated reactor vessel level is function of injection rate into the shroud and bottom head versus leakage rate out the jet pump nozzles.

Immediately following a LOCA, the first priority is adequate core cooling which is achieved when <u>indicated</u> reactor vessel water level is maintained above top of active fuel (TAF). A single core spray pump is capable of maintaining level at or above $^2/_3$ core coverage by design. A core spray pump and LPCI pump will maintain a higher level inside the shroud, but may not sustain an indicated level above TAF. Therefore, since indicated level after reflood (for the

analyzed range of liquid line break sizes) will read above $^{2}/_{3}$ core coverage but could read less than TAF and certainly below the normal level, containment cooling for a liquid break will be handled differently than a steam line break.

Containment Cooling for liquid line breaks is performed in two steps:

1. It is assumed that at 10 minutes, RBCCW cooling water flow is applied to the RHR heat exchanger. The RHR heat exchanger bypass valve is in it's normal full open position. No disruption of LPCI is required to enter this mode of suppression pool cooling. The heat removal achieved by this mode of "LPCI with Heat Rejection [2 pumps, heat exchanger bypass valve full open]" are based on ~40% of the flow from the two RHR pumps passing through the RHR heat exchanger. This mode does not give rated heat removal because it does not provide rated flow through the heat exchanger.
2. At 2 hours it is assumed that a transition is made which will give rated heat removal by increasing the flow rate through the RHR heat exchanger to rated flow. Two hours gives a reasonable amount of time for operators to observe and decide that vessel level probably cannot be recovered above TAF (the level which provides adequate core cooling per EOP-01) and to begin primary containment flooding per EOP-09 "Primary Containment Flooding". Anytime after the commencement of primary containment flooding, the operator can establish "LPCI with Heat Rejection [1 pump, heat exchanger bypass valve closed]". The heat removal achieved by this mode of "LPCI with Heat Rejection [1 pump, heat exchanger bypass valve full closed]" is based on 100% of the flow from a single RHR pump passing through the RHR heat exchanger. This mode gives rated heat removal.

   The transition to the second step of suppression pool cooling requires:

   A. Removal of one RHR pump from service.

   B. Closure of the heat exchanger bypass valve.

   C. Necessary valve position adjustments to maintain rated flow through the RHR heat exchanger.

Although the lineup will be different, the effectiveness of containment cooling will not be compromised, and the overall plant response to the event will remain within equipment capability.

Question 6:

> *Provide reference 22, GE-NE-T23-00732-01, "Pilgrim Nuclear Power Station Containment Heat Removal Analysis," March 1996, (SUDDS/RF96-05, Rev. 0), which performs the design basis LOCA analysis using 75°F SSW inlet temperature.*

Answer:

GE considers GE-NE-T23-00732-01 as General Electric Proprietary information, as described in 10 CFR 2.790(a)(4). We will submit this report under separate cover with the appropriate proprietary information affidavit.

Question 7:

Pages 26 and 27 of SE 2983 discuss the ECCS NPSH calculations for the two design basis LOCAs. FSAR Figures 14.5-10 and 13 and Figures 14.5-18 and 19 depict the NPSH availability for RHR and core spray pumps with leakage effects included for the 65°F and 75°F SSW inlet temperatures, respectively. The licensee evaluated the potential effect of insulation debris accumulating on the ECCS strainers and concluded that the increased suction head loss from the debris is within the margin for NPSH available to the ECCS pumps. The staff notes that the FSAR figures depict the licensee's calculated NPSH margin based on clean strainers. Debris on the ECCS strainers reduces the NPSH available, and this fact should be depicted on the FSAR figures. Additionally, the staff notes that the margin depicted on the FSAR figures are not the licensing basis margin. Credit for the margin above atmospheric pressure entails changing the licensing basis margin.

Answer:

The design condition for the ECCS pumps is the nominally clean strainer and undegraded suction condition. Numerous safe shutdown events add energy to the suppression pool through the safety relief valves or steam-driven turbine exhaust and are bounded by the design basis LOCA suppression pool temperature response and NPSH analysis. However, events such as these do not involve any insulation destruction and no additional debris head loss. Oftentimes, the design basis LOCA NPSH analysis results are referenced or used as the basis for adequacy of NPSH following these other events that do not involve head loss from debris. Therefore, Boston Edison chose to present the NPSH analysis results for the design condition and compare the available NPSH margin under clean conditions against estimated debris head losses to verify design adequacy.

The NPSH margin indicated on the UFSAR figures represents a lower bound prediction of the margin available if containment integrity remains. Minimal NPSH margin is available if the containment pressure above atmospheric is not part of the licensing basis margin. In fact, the NPSH margin below one atmosphere does not even meet ordinary engineering guidelines for desired NPSH margin for a centrifugal pump. When single stage ECCS pumps were selected for PNPS, it was well known that the NPSH requirements were moderate and that at the maximum suppression pool temperature minimal NPSH margin would remain at if an atmospheric pressure limit was used. However, the containment system, being a closed sump, provides NPSH margin that inherently increases with pool temperature as described in SE 2971. It is our conclusion that the designers could only have considered this total margin, as presented in the original FSAR, for the design to have been considered adequate.

In the event containment integrity is not sufficient to provide the necessary containment pressure above atmospheric and cavitation degrades the performance of the RHR or core spray pumps, salt service water (SSW) pumps can be used to inject seawater into the reactor vessel or primary containment through the SSW intertie to the RHR system. The SSW pumps are located outside the reactor building in the Class I portion of the intake structure and are mechanically independent from the RHR and core spray pumps. This intertie is described in

UFSAR section 4.8 which states the piping connection is sized to provide 5,000 gpm at 0 psig reactor pressure. All piping and equipment in the SSW system and the piping connection are designed to Class I seismic requirements.

Once implemented, use of the SSW system in this manner would provide immediate benefits by providing core cooling, significantly lowering the suppression pool temperature, increase the elevation head provided at the RHR and core spray pump suctions, and eventually provide complete core coverage. Primary containment flooding, which may use additional sources of water such as condensate transfer and firewater systems is preferred over long term recirculation and is called for by Emergency Operating Procedures when reactor level cannot be restored above TAF. Therefore, the SSW intertie provides an independent means of accomplishing core and containment cooling functions in the event the containment conditions degrade in an unanticipated manner such that RHR or core spray pumps are unable to achieve their rated performance.

Question 8:

> *Page 2 of letter dated January 20, 1997, E. T. Boulette to the NRC, states that with the maximum debris loading, a torus airspace pressure of approximately 4.1 psig is required at the peak suppression pool temperature of 178°F to provide the required NPSH for both the RHR and CS pumps. Using Pilgrim's calculation M-662, the staff calculated that 3.6 psig is required for the 8.6 feet of head loss due to the maximum debris loading. Provide the details of the calculation for the required containment overpressure for adequate NPSH at the peak suppression pool temperature of 178°F.*

Answer:

The following information is excerpted from calculation M662, and the equations are modified to include the debris head loss term.

NPSHA is defined by the following terms:

Eq. 1 $$NPSHA = (Pc - Pvp)\frac{\left(144\frac{in^2}{ft^2}\right)}{\rho} + H_z - H_{sl} - Hdebris$$

Where:

Hz	*Elevation of suppression pool water surface above the pump inlet, ft*
Hsl	*Suction line losses, ft*
Hdebris	*Head loss from debris, ft*
NPSHA	*Net positive suction head available, feet*
NPSHR	*Net positive suction head required, feet*
Pc	*Pressure of primary containment, psia*
Pc Req'd	*Pressure of primary containment required to provide NPSHR, psia*
Pvp	*Vapor pressure at pool temperature, psia*
ρ	*Density of water in pool, lb/ft^3*

The containment pressure required to provide adequate NPSH is derived using Equation 1 by letting NPSHA equal NPSHR and solving for the containment pressure *Pc*. When NPSHA equals NPSHR, the containment pressure is by definition equal to the required containment pressure *Pc Req'd*.

Eq. 2 $$Pc\ Req'd = Pvp + (NPSHR - Hz + Hsl + Hdebris)\frac{\rho}{\left(144\frac{in^2}{ft^2}\right)}$$

The following input parameters are used in Eq. 2 to calculate the pressure required to provide adequate NPSH of 4.1 psig.

Input Parameter	RHR Pump	Core Spray Pump
Hz (ft)	12.5	12.5
Hsl (ft)	2.63	2.40
Hdebris (ft)	14.5	8.6
NPSHR (ft)	23	29
Pvp (psia) @ 178°F	7.184	7.184
ρ of pumped fluid (lb/ft3) @ 178°F	60.625	60.625

	RHR Pump	Core Spray Pump
Pc Req'd for pump with maximum debris on suction strainer (psig)	4.11 Rounded to 4.1 psig	4.06 Rounded to 4.1 psig

Based on the above equations and calculation, 4.1 psig is required* to provide adequate NPSH at the peak suppression pool temperature of 178°F.

Question 9:

Upon review of the Pilgrim FSAR, the staff noted that there are two sections 14.5.3.1.3, Core Standby Cooling System Pump Net Positive Suction Head; one which begins on page 14.5-10 and one on page 14.5-11. It appears that the first section 14.5.3.1.3 was for the 65°F salt service water case; however, the 75°F salt service water case is discussed in the last three paragraphs of this section. The second section 14.5.3.1.3 discusses both the 65°F and the 75°F SSW injection temperature cases. Which section 14.5.3.1.3 is the applicable section for the design basis net positive suction head calculation? Provide an explanation as to why the 75°F SSW injection case does not bound the 65°F SSW case.

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* Large capacity stacked disk strainers were installed prior to startup from RFO #11. The larger surface area of these strainers, reduces the pressure required to meet pump NPSH requirements. Please refer to the response for question 6 on Attachment 2 for additional information on containment pressure requirements.

Answer:

Revision 19 to the UFSAR contained purely editorial errors that were made incorporating SE 2971 and SE 2983 into UFSAR Section 14.5.3.1.3. Revision 20, issued on February 19, 1997, (BECo letter 2.97.019) corrected the inadvertent incorporation of a draft page 14.5-10 into the final package. Please refer to the newest version of section 14.5.3.13.

Question 10:

Page 14.5-12b of the FSAR, part of the second section 14.5.3.1.3, discusses NPSH available under RCIC operation. Based on the model assumptions and the NPSH required, (i.e., 28 ft), this part of the FSAR is not consistent with the new 65°F and 75°F NPSH analyses. Was NPSH reanalyzed for these two cases under RCIC operation?

Answer:

The RCIC NPSH analysis presented in Section 14.5.3.1.3, which used an ultimate heat sink temperature of 65°F, was not repeated using a ultimate heat sink temperature of 75°F. However, as stated in Section 14.5.3.1.3, the peak suppression pool temperature for this scenario is 163°F, and using a 75°F ultimate heat sink temperature should be no greater than 173°F which is less than the peak suppression pool temperature associated with the design basis LOCA. Furthermore, the scenario analyzed for RCIC is a safe shutdown scenario rather than a pipe break accident. Therefore, no debris related head loss from insulation is involved for any of the pumps used during the safe shutdown. Based on these facts, reanalysis of this scenario was not performed since the design basis LOCA NPSH analysis is more limiting.

Question 11:

SE 2983 evaluates the changes to the local pool temperature limits, design basis LOCA analysis, FSAR steam line break analysis, Appendix R fire events, ATWS, station blackout, containment metal-water reaction capability, ECCS NPSH, suppression pool temperature, component cooling, building compartment cooling, environmental qualification, standby gas treatment, standby AC power sources, and piping design due to the increased SSW inlet temperature of 75°F. According to SE 2983, new analyses were performed to verify that the increase of SSW inlet temperature is within the design basis of the affected systems. It is not clear to the staff that the increase of SSW inlet temperature is within the design basis of the affected systems and that the increase in temperature will not increase the consequences of an accident previously evaluated in the FSAR. Provide a discussion as to why the increase of service water temperature is not an unreviewed safety question.

Answer:

The site maximum SSW inlet temperature of 75°F from UFSAR section 2.4.2 does not change or influence factors that might cause an accident evaluated in the FSAR to occur and, therefore, will not increase the probability of occurrence of an accident previously evaluated in the FSAR.

Furthermore, the plant was designed to operate normally with a seawater temperature of 75°F. Therefore, operation at 75°F seawater temperature will not increase the probability of occurrence of transients (e.g., loss of condenser vacuum) that might challenge safety-related systems.

With regard to the potential for the proposed change to increase the consequences of an accident previously evaluated in the FSAR, at the site maximum SSW inlet temperature, the core, containment, component, and building compartment cooling systems are capable of meeting all performance requirements necessary to ensure physical barriers against the release of radioactive materials perform as intended to limit offsite dose consequences to those previously evaluated in the FSAR.

With regard to the possibility that the proposed change could increase the probability of occurrence of a malfunction of equipment important to safety previously evaluated in the FSAR, although the site maximum SSW inlet temperature of 75°F results in higher temperatures in the plant than would be seen at the design value of 65°F, systems, structures and components important to safety can reliably perform as intended during each of the design basis events.

With regard to the possibility that the proposed change increases the consequences of a malfunction of equipment important to safety previously evaluated in the Final Safety Analysis Report, at the site maximum SSW inlet temperature, the core, containment, component, and building compartment cooling systems are capable of meeting all performance requirements necessary to ensure physical barriers against the release of radioactive materials perform as intended to limit offsite dose consequences to those previously evaluated in the FSAR.

With regard to the possibility that the proposed activity creates the possibility of an accident of a different type than any previously evaluated in the Final Safety Analysis Report, there are no new accident initiators or failures resulting from a SSW inlet temperature of 75°F versus 65°F. The types and basic nature of accidents associated with the station design is unchanged.

With regard to the possibility that the proposed activity creates the possibility of a different type of malfunction of equipment important to safety than any previously evaluated in the Final Safety Analysis Report, although the site maximum SSW inlet temperature of 75°F results in higher temperatures and pressures in the plant than would be seen at the design value of 65°F, there are no new or different types of equipment malfunction caused by these changes.

With regard to the potential to reduce the margin of safety as defined in the basis for any Technical Specification, Technical Specification Bases 3.5.B "Containment Cooling" states that "Each system has the capability to perform its function; (i.e., removing 64 x 10^6 Btu/hr (Ref. Amendment 18), even with some system degradation." This heat removal capability refers to the containment cooling heat load from the RHR heat exchanger and is based on the SSW inlet temperature design value of 65°F. In addition to the containment heat load, the closed cooling water loop also removes approximately 1 x 10^6 Btu/hr from other essential equipment during a design basis LOCA. Using the FSAR site maximum ultimate heat sink temperature of 75°F for the SSW inlet temperature, each system has the capability to remove 65.1 x 10^6 Btu/hr with some degradation. In addition to the containment heat load, the closed cooling water loop also removes approximately 1 x 10^6 Btu/hr from other essential equipment during a design basis LOCA. Based on the above information this change does not reduce the margin of safety in the basis for any technical specification.

RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION (RAI) DATED
MARCH 13, 1997
(ENCLOSURE 2, QUESTIONS 1 THROUGH 10)

Question 1:

SE 2971: How was the suppression pool temperature profile, used to determine the containment pressure, calculated? Specify what code was used.

Answer:

The suppression pool temperature profile in SE 2971 is from the Pilgrim UFSAR (Fig. 14.5-7) and is unchanged from the original SAR. The basic principles and equations used for the original short term and long term containment accident response are explained in UFSAR Appendix R Section R.5.4 which includes a statement that the equations described were programmed for computer solution. Time derivatives were integrated using numerical methods, and thermodynamic properties were found by tabular interpolation. The analytical tools and computer codes used by General Electric for the original Pilgrim analyses are not available to BECo. For the time frame and vintage of these original analyses (1967), GE no longer maintains the actual codes used in these calculations; rather, they are used as a benchmark for their current analytical models when a new calculation is required. It is assumed that that the earlier methods were fundamentally similar in that they were finite time increment mass and energy balance models as described below.

For the new analyses performed with a 75°F ultimate heat sink (UHS) included in SE 2983, the temperature and pressure profiles for the drywell and wetwell and the suppression pool temperature profile were calculated by GE [Ref. 1 to this attachment] as part of the containment heat removal analysis. The calculation utilized the GE computer code SHEX, which is a coupled pressure vessel and containment model for the first day into the event. The code performs fluid mass and energy balances on the reactor primary system , the suppression pool, and the drywell and wetwell airspaces. These mass and energy balances are updated in finite time increments starting at the initial conditions and proceeding based on the decay heat profile as an energy input and with heat rejection to the ultimate heat sink via the RHR system and, for the NPSH analysis only, to passive heat sinks in the drywell and wetwell. For the period from 1 to 35 days into the event, a simpler thermal-hydraulic model was used. This model performed the mass and energy balances for the suppression pool and the drywell and wetwell airspaces, including the effects of containment sprays.

The analytical models performed air mass balances in the drywell and wetwell, incorporated the effects of containment leakage, and determined the temperature and pressure response in the drywell and wetwell. Since in a DBA-LOCA the containment sprays are not activated and results from SHEX show that at the end of 2 days the drywell has essentially reached equilibrium with the suppression pool, the drywell temperature is set equal to the suppression pool in the DBA-LOCA calculations after 2 days into the event.

Question 2:

2. *SE 2971: Why wasn't SHEX used to compute the pressure for SE 2971? Explain why you believe the ideal gas formulation for the noncondensables is adequate, versus use of a computer code. Discuss the conservatism/nonconservatism of the method you have used, as well as any other differences between the two methods.*

Answer:

The purpose of SE 2971 was to supersede SE 1638 (issued in 1984) which was found to erroneously conclude that the Pilgrim ECCS pumps had adequate NPSH with the suppression pool at maximum temperature, with maximum LOCA-generated debris, and no containment overpressure. SE 2971 was intended to correct the record from 1984 regarding ECCS pump NPSH and the Pilgrim design basis NPSH analysis methods. As such, SE 2971 utilized the original FSAR suppression pool temperature profile for the single RHR loop cooling modes. The same profile applied to both the suppression pool cooling and containment spray modes, with a peak temperature at 166°F occurring approximately 5.5 hours into the event.

The 75°F UHS analysis for Pilgrim was performed by GE [Ref. 1 to this attachment] subsequent to SE 2971. As part of this work, the SHEX computer code was used to perform the NPSH analyses of the steam line break (SLB) events. The GE analysis generated a new DBA-LOCA suppression pool temperature profile that was used as the basis for updating NPSH Calculation M-662 Rev. E1 [Ref. 3 to this attachment] to include the 75°F UHS case. The NPSH calculations performed by GE using the SHEX code demonstrated that the SLB events are not more limiting with regard to NPSH when compared to the Calculation M-662 equilibrium method for the DBA-LOCA. This is a fundamental premise of the Pilgrim NPSH analysis method and is consistent with the original design basis calculations. The calculation method described in SE 2971 and embodied in Calculation M-662 is based on the following conclusion that is applicable to Pilgrim:

> *NPSH calculations that assume the containment atmosphere is in equilibrium with the suppression pool, and which utilize the design basis accident pool temperature profile with sufficient accounting for the initial drywell and wetwell conditions and containment leakage, represent the bounding case for determining the minimum margin for NPSH available to the ECCS pumps. More complex mechanistic analyses utilizing containment spray for steam line breaks demonstrate greater NPSH margins than that obtained from the assumption of equilibrium conditions for the design basis loss-of-coolant accident.*

The GE analysis using the SHEX code included the most limiting large steam line break (1.0 ft^2) with reactor flooding and containment spray assumed which reduces the drywell pressure to its minimum value. Large steam line breaks (greater than 0.35 ft^2) immediately depressurize the reactor vessel which is reflooded by the LPCI and core spray systems. Since normal reactor water level is reestablished after a steam line break, the RHR pumps are removed from LPCI and one core spray pump maintains water level by intermittent additions as needed to makeup for boiloff. For the steam line break (SLB) with reactor flooding assumption, the core

spray pump is assumed to continuously flood the core and flow out of the vessel while one RHR pump operates in the containment spray mode. The SLB with reactor flooding is the most limiting containment spray case for NPSH analysis since it minimizes containment pressure. All other steam line break cases are based on the reactor vessel being maintained at normal water level with core steam generation as the means for heat transfer to the containment.

For a large steam line break, it is more limiting to assume continuous reactor flooding because it results in a subcooled core without steam generation, similar to the DBA-LOCA response. The steam line break cases are consistent with the BWR Emergency Procedure Guidelines and the Pilgrim EOP's in that these procedures would allow operators to initiate containment sprays because there is adequate reactor water level at all times following the reactor reflood after a steam line break. A comparison of Calculation M-662 and the SHEX model NPSH margins for design basis line breaks are as follows:

DBA-LOCA versus 1.0 ft^2 SLB NPSH Margin

Core Spray Pump NPSH Margin:

Calc M-662 Rev. E1	SHEX Model GE Table 5-7	
16.5 ft	19.5 ft	@ Peak Pool Temperature
10.8 ft	12.7 ft	@ Minimum NPSH Margin

RHR Pump NPSH Margin:

Calc M-662 Rev. E1	SHEX Model GE Table 5-7	
22.3 ft	25.2 ft	@ Peak Pool Temperature
16.6 ft	18.4 ft	@ Minimum NPSH Margin

There is also the case of very small (0.01 ft^2) steam line breaks, which produce lower NPSH margin at the peak pool temperature, but not at the point of minimum NPSH margin as shown in the following comparison:

DBA-LOCA versus 0.01 ft^2 SLB NPSH Margin

Core Spray Pump NPSH Margin:

Calc M-662 Rev. E1	SHEX Model GE Table 5-6	
16.5 ft	13.0 ft	@ Peak Pool Temperature
10.8 ft	11.7 ft	@ Minimum NPSH Margin

RHR Pump NPSH Margin: Calc M-662 Rev. E1	SHEX Model GE Table 5-6	
22.3 ft	18.8 ft	@ Peak Pool Temperature
16.6 ft	17.5 ft	@ Minimum NPSH Margin

Although the small steam line break produces a lower NPSH margin at the peak pool temperature, it is not more limiting than the DBA-LOCA overall. The reason for the lower NPSH at peak pool temperature is simply because the containment spray is able to completely condense the small amount of steam released and to further subcool the drywell atmosphere below the temperature of the suppression pool. A small steam line break is an inherently less limiting accident mode than the DBA-LOCA or large steam line break from the standpoints of core cooling, NPSH, and containment cooling.

It is concluded that the NPSH analysis of the DBA-LOCA in Calculation M-662 together with the GE SHEX analysis of steam line break events represent a complete and appropriate evaluation of NPSH margins available to the ECCS pumps and that this comprises the Pilgrim design basis for ECCS pump NPSH.

Question 3:

> *SE 2971: Does SE 2971 describe the current design basis for ECCS pump NPSH? If not, what is the current design basis? In particular, does it assume 65°F seawater temperature or 75°F seawater temperature and strainer clogging? How much overpressure is needed? The staff needs to know explicitly the design basis regarding NPSH for the RHR and CS pumps, including the codes and assumptions used to calculate the containment pressure for NPSH purposes. State how calculation M662 ties in with SE 2971 and 2983.*

Answer:

The current design basis for ECCS pump NPSH is calculation M-662, Rev. E1* , which includes the design basis analysis performed for a 75°F seawater temperature. The Safety Evaluation that adopted this analysis for a 75°F UHS and updated the UFSAR is SE 2983. The current analysis for ECCS suction strainer head loss due to LOCA generated debris is a GE analysis [Ref. 2 to this attachment] that was performed in accordance with NRC Regulatory Guide 1.82 Rev. 1. As discussed above, SE 2971 was issued to supersede SE 1638 (issued in 1984) and to correct the record on NPSH calculations using the original design basis accident analyses performed with a 65°F UHS. Calculation M-662, Rev. E0, supported SE 2971 and was subsequently superseded by M-662, Rev. E1, that added the 75°F UHS analysis for NPSH margin in support of SE 2983. The suction strainer debris loading is the same in calculation M-662, Rev. E0, and E1. It is intended that the strainer debris loading will

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* Calculation M-662, Rev. E1, was revised to support the interim safety evaluation (SE3088) submitted April 11, 1997 prior to restart from RFO # 11. The current M-662, Rev. E2, retains the information referred to in this response.

be further revised as part of BECo's response to NRC Bulletin 96-03 and calculation M-662 will be revised again to include the new debris analysis in support of a license amendment request to credit more containment pressure for NPSH margin.

The basic approach of the SE 2971 and Calculation M-662 method is consistent with the NPSH analysis method included in the original Pilgrim FSAR. During the Pilgrim licensing process, Amendment 9 to the SAR was issued in 1968 to describe the NPSH analysis method for the ECCS pumps. This method calculates the NPSH margin available versus time for the DBA-LOCA using the suppression pool temperature profile and an appropriate set of initial conditions and including the effect from containment leakage. This NPSH margin is a conservative lower bound value based on the containment atmosphere being in equilibrium with the suppression pool. The NPSH margin varies with time, tending to increase as pool temperature rises, then decreasing after the pool temperature peaks, with the minimum margin occurring at the point when the containment pressure has dropped to equal atmospheric pressure. The point of minimum margin is heavily influenced by the cooldown of the pool, containment leakage, and the temperature at which atmospheric pressure is reached.

In calculation M-662, the NPSH margin, in feet versus time, is plotted directly. These figures were added to the Pilgrim UFSAR by SE 2971 (Fig. 14.5-13 for 65°F UHS) and SE 2983 (Fig. 14.5-19 for 75°F UHS). Pilgrim proposes these NPSH margin curves represent the design basis for the ECCS pump NPSH. It should be noted that the NPSH margin shown in these figures is the total available margin with the suction conditions at their design values; that is, the strainer is nominally clean and the suction path unrestricted and undegraded. The usefulness of this approach becomes apparent when evaluation of strainer clogging must be included. Since strainer clogging is event-specific, the debris can be calculated and used to determine the resulting strainer head loss, in feet, at the appropriate flow rate. The debris head loss can then be compared to the NPSH available margin, both expressed in feet, to determine the adequacy of the strainer.

Although overpressure requirements can be expressed in terms of psig containment pressure, the above discussion shows that the NPSH margin is the most fundamental parameter for describing the adequacy of ECCS pump suction conditions. The results in calculation M-662, Rev. E1, show the peak containment equilibrium pressure determined for the DBA-LOCA is 7.4 psig when the suppression pool peaks at 178°F. The total NPSH margin at the peak pool temperature is 16.5 ft for the core spray pumps and 22.3 ft for the RHR Pumps. At the point of minimum NPSH margin, the containment pressure is 0 psig at 126°F, and the margin is 10.8 ft for the core spray pumps and 16.6 ft for the RHR pumps.

Question 4:

> *Calculation M662: In calculation M662, initial wetwell airspace pressure is given as 0.5 psig on sheet 6 of 84, whereas it is given as 0 psig on sheet 15 of 84. Which value is actually used?*

Answer:

The value of 0.5 psig is used as the initial condition for containment in calculation M-662. The initial wetwell pressure (Section 3.C.5) of 0 psig referred to is the actual wetwell pressure (at 80°F, 100% RH) while 1.30 psig is the drywell pressure (at 150°F, 80% RH) prior to the DBA-LOCA. The equilibrium method used in this calculation treats the post-accident containment as one volume. The calculation, therefore, converts the initial conditions in the drywell and wetwell into the equivalent condition if the two air masses were mixed since the initial vessel blowdown effectively equalizes the drywell and wetwell airspaces. This equivalent pressure is 0.55 psig as shown in Section 3.C.5 of M-662.

Question 5:

> *Calculation M662: In Table 8 of calculation M662, the wetwell free volume in the Amendment 9 column is given as 120,000 cu. ft.; whereas in the more recent analyses given in the other columns, it is given as 124,500 cu. ft. Why are these different?*

Answer:

The value of 120,000 ft^3 is the nominal wetwell airspace volume at the normal water level. The value of 124,500 ft^3 is the calculated value [Ref. 4 to this attachment] for the minimum allowed water volume of 84,000 ft^3 (Tech. Spec. 3.7.A.1.a). The NPSH analysis uses minimum torus water volume as the initial condition.

Question 6:

> *Calculation M662: In Table 8 of calculation M662, in the 65 and 75 deg F columns for initial drywell relative humidity, the relative humidity is given as 80%, versus 100% in the Amendment 9 column. 80% seems less conservative from a minimum pressure perspective, since it tends to increase noncondensables in containment, resulting in a higher, not minimum, containment pressure.*
> *Discuss why this apparently non-conservative change was made in the relative humidity.*

Answer:

The change in the drywell initial relative humidity from 100% to 80% was as a result of a complete reassessment of all input assumptions as summarized in Table 8 of calculation M-662. As a result, changes were made to the SSW flow rate, the RHR and core spray pump flows and NPSH required, wetwell volumes, suction line head losses, and containment initial conditions.

The change in the drywell relative humidity (RH) was based on the conclusion that the original assumptions, although more conservative, were outside the bounds of possible conditions. The drywell is inerted with dry nitrogen for normal plant operation, and bulk temperatures are generally below 130°F. It is also required (Tech. Spec. 3.7.A.1.i) that a differential pressure of 1.17 psid minimum be maintained between the drywell and wetwell. There is a scram setpoint for high drywell pressure at 2.2 psig. Therefore, there is only a 1.03 psi increase in drywell

pressure that is allowed before the reactor is automatically shutdown. If the normal condition were 150°F at 20% RH at 1.17 psig drywell pressure, then the 2.2 psig maximum would be reached simply by the change in water vapor pressure in going to 150°F at 48% RH. It is not considered a credible condition for the drywell to be at 150°F at 100% RH at 0 psig as was assumed in the original analysis. The new initial conditions are considered to be conservative since they represent an unusually high temperature and humidity at an otherwise normal drywell pressure (1.3 psig).

Changes to assumptions such as those above were made by applying the principle that design basis calculations must be conservative overall and, where appropriate, bounding for most individual parameters. However, instances should be avoided where assumptions represent improbable or impossible combinations of parameters so that the design basis does not mislead or result in unwarranted decisions or actions in response to an actual event. The current set of assumptions used in the containment heat removal analyses [Ref. 4 to this attachment] are believed to be the most appropriate and were developed from a careful review of many interrelated calculations. We believe that the analyses performed are as conservative overall as the original design basis analyses and that conservatisms are more appropriately applied to each individual parameter.

Question 7:

Calculation M662: In calculation M662, discuss more fully the effect of an initial drywell temperature of 150 deg F versus 135 deg F, and the rationale for choosing 150 deg F.

Answer:

The 150°F drywell temperature is unchanged from the original NPSH analysis. Although 135°F is used in the containment analysis for design basis accidents, it is more conservative to assume a higher initial temperature for the NPSH analysis. The higher temperature at higher humidity results in lower initial mass of noncondensible gas (nitrogen) which minimizes the post-accident containment pressure and hence the NPSH available. As discussed for question #6 above, the original input assumptions were reviewed, and the 150°F drywell temperature was determined to be an appropriate upper bound.

Question 8:

Calculation M662: In calculation M662, you assume that the steam space pressure of the containment atmosphere cancels with the vapor pressure of the suppression pool; i.e., they are both saturated. This is dependent on the mixing assumptions between the atmosphere and pool. What assumptions are made in the SHEX code (e.g., complete mixing, water falls directly to pool, etc.)?

Answer:

Calculation M-662 is based on an equilibrium model for the containment and the suppression pool. The basis, in question #2 above, is that this model is bounding when used to determine

the minimum NPSH margin for the DBA-LOCA. The SHEX code was used by GE for the steam line break analyses. The SHEX code uses a mechanistic analysis of containment spray and the mass and energy transfer between the reactor vessel, drywell and wetwell, with different conditions existing in each volume. The results from SHEX differ from the M-662 model in that SHEX has separate conditions in the drywell and wetwell airspaces. Therefore, although the wetwell pressure is approximately equal to the drywell, there is a difference in the drywell versus wetwell temperature. The drywell is typically well above the suppression pool temperature while the wetwell airspace is subcooled to below the pool temperature. The resulting drywell and wetwell pressures are consistently greater than the equilibrium pressure determined in M-662, resulting in a less limiting NPSH condition for the steam line break analysis.

The general conclusion can be made that achieving equilibrium conditions between the drywell and suppression pool while maximizing heat transfer from the reactor core is an inherently acceptable condition that is, in effect, the goal of accident response procedures. This condition can be approached by some combination of core cooling via either boiling with level control and containment spray or subcooled continuous flooding with or without containment spray. The SHEX code shows that equilibrium is approachable for the DBA-LOCA response after the first 30 minutes. For the large steam line break, the drywell will remain at a temperature and pressure above equilibrium. From small steam line breaks, it is possible to subcool the containment to slightly below the equilibrium temperature at the peak pool temperature, but the M-662 analysis remains bounding at the point of minimum NPSH margin.

The accident response includes continuous flooding of the reactor core for the DBA-LOCA and the steam line break with reactor flooding. For both cases, the flow out of the vessel, through the break, is
modeled in the SHEX code in a manner similar to containment spray although at a lower spray heat transfer efficiency. This vessel outlet flow and containment spray both promote mixing of the atmosphere and the pool. For the DBA-LOCA, the SHEX analysis shows that equilibrium conditions are achieved at approximately the time that the peak pool temperature is reached (UFSAR Fig. 14.5-17). The DBA-LOCA includes that most rapid suppression pool heatup to 178°F and, hence, represents the most efficient transfer of heat from the reactor core to the pool and the ultimate heat sink. For the large steam line break with reactor flooding, the drywell remains above the equilibrium temperature throughout the cooldown, despite the spray flows. The resulting suppression pool heatup approaches that of the DBA-LOCA with a peak temperature of 177°F.

Question 9:

> *Calculation M662: Provide a discussion of the differences between the input parameters in the benchmark and revised analyses given in Table 2 of calculation M662. Discuss any differences in the results, and in particular, discuss the effect of differences in input parameters on the calculated results.*

Answer:

Part of this answer is provided in responses to questions 4, 5, 6, & 7 above. The changes to NPSH analysis input assumptions were as a result of a complete reassessment of all input assumptions as summarized in Table 8 of calculation M-662. Changes were made to the input parameters for the design containment leakage rate, SSW flow rate, the RHR and core spray pump flows and NPSH required, wetwell volumes, suction line head losses, and containment initial conditions. The design containment leakage rate was changed from 0.5% per day to 1% per day since this is the basis for the Technical Specification 4.7.A requirements for containment leak rate testing. The impaired containment leak rate of 5%/day was not changed. Containment leakage was also modeled as a function of containment positive pressure rather than as a fixed mass of air corresponding to 1.5 days leakage subtracted from containment at the initial condition.

The SSW design basis flow rate to the RBCCW heat exchanger was changed from 5000 to 4500 gpm for all heat removal analyses. This was based on an updated SSW system hydraulic design basis analysis for which the assumptions were also updated. The new SSW analysis is based on minimum allowable SSW pump performance, maximum allowable RBCCW heat exchanger tube plugging, and design low tide level. It was determined that the original design flow rate of 5000 gpm may not be achieved at all times and that 4500 gpm was an appropriate lower bounding flow rate.

The RHR and core spray pump flow rates were assumed to be the maximum for the most limiting accident conditions which resulted in a greater NPSH requirement of 29 feet for the core spray pump. The preliminary design number of 28 feet used for all ECCS pumps in the original analysis was greater than the actual RHR pump NPSH requirement of 23 feet.

Tables 1 through 4 of calculation M-662 summarize the hydraulic analysis for the ECCS pump suction piping. This analysis is based on the actual as-built piping configuration using appropriate friction losses for piping and K values for valves and fittings. The suction piping head loss used in the original analysis is higher and appears to have been a nominal design value before the actual piping configuration was known. The clean strainer head loss is based on the strainer rating.

The result of the changes to inputs and assumptions can best be seen by comparing calculation M-662 Figures 2 and 4 for the 5%/day leakage case. The suppression pool temperature profiles are identical with a peak at 166°F. The peak containment pressure at 166°F in the new analysis is 20.2 psia versus 18.0 psia in the original analysis. The point of minimum margin in the new analysis is 11.5 feet at 119°F (using core spray pump $NPSH_R$ = 29 ft) versus 8.5 feet at 136°F (using $NPSH_R$ = 28 ft) in the original analysis. Thus, it is seen the new analysis provides more favorable results, but, as described earlier, there is an appropriate level of conservatism, and it is more clearly defined than in the original documentation.

Question 10:

SE 2983: What is the rationale for choosing 1.3 psig initial pressure in the drywell and 0.0 psig in the wetwell, versus assuming 0.0 psig (i.e., atmospheric) in both the drywell and wetwell? What are the normal operating conditions in the drywell and wetwell? Does 1.3 psig in the drywell tend to help minimize the containment pressure response, or would a lower initial pressure be more suitable for the minimum pressure calculation necessary for NPSH overpressure calculations?

Answer:

Please refer to the question #6 response above. The drywell and wetwell initial conditions were changed from those in the original analysis. Pilgrim uses nitrogen inerting of containment and has a license requirement (Tech. Spec. 3.7.A.1.i.) that a differential pressure of 1.17 psid minimum be maintained between the drywell and wetwell during power operation. The initial drywell condition of 150°F and 80% RH is an unusually high temperature and humidity, both of which increase pressure. It was, therefore, concluded to be improbable for the plant to be operating at full power with a drywell condition of 150°F at 100% RH at 0 psig. The normal conditions are a bulk average temperature of less than 130°F at approximately 1.3 psig drywell pressure with relative humidity assumed to be below 20%. The NPSH analysis yields lower NPSH available with any change in a parameter that decreases the mass of noncondensible gases (nitrogen) in containment. Therefore, the original assumed drywell conditions were more limiting, but, as discussed in #6 above, the new values are considered to have more appropriate conservatism.

Additional Question (Enclosure 3 of the March 13, 1997, NRC RAI):

Question 1

> *On page 14 of 84 of calculation M-662, there is an equation 10 which provides the maximum allowable suction line pressure loss. This equation includes a net positive suction head margin (NPSHM) term which inappropriately increases the allowable suction line loss. Also, the NPSHM term has nothing to do with possible piping obstruction degradation and increase in suction line pressure loss from the appropriate test reference value for the test flow. Should the suction line pressure loss calculation be modified?*

Answer:

Equation 10 in calculation M-662 is in Section 3.C.4 "Maximum Allowable Pump Suction dP @ IST conditions". The purpose is to determine the maximum pressure drop that may be measured on an RHR or core spray pump suction during the quarterly In-Service Test (IST) per the Pilgrim ASME Code Section XI testing program. The measured suction pressure drop, in psi, is the difference between the zero flow and full flow pressure as measured with a static pressure gage at the pump suction. Table 4 in M-662 gives the calculated pressure drop for the pump test flow rates at 80°F with the suction strainer clean and no other suction degradation. The calculated values in Table 4 for the test condition with a clean strainer have been verified to be in close agreement with actual IST measured values.

Tables 5, 6, & 7 of M-662 include a column listing the "Max dP Measured @ IST Conditions (psi)". To obtain this value, Equation 10 is used to determine the dP, measured at the IST conditions, that would show an amount of suction strainer clogging exactly equal to the "Available Margin" calculated by Equation 9. Where shown, the available margin is the remaining NPSH margin after the LOCA debris head loss has been added to the clean strainer head loss. Thus, in effect, the IST condition is used to assess that the strainer is clean during normal operation, or more precisely, not fouled to the point at which it would be unable to accommodate the postulated LOCA debris head loss.

The IST acceptance criteria is based on the most limiting accident dP value, which is obtained from Table 7, for a pool temperature of 126°F with LOCA debris included. Therefore, the IST suction pressure drop acceptance criteria is 1.9 psi for core spray pumps and 2.1 psi for RHR pumps. Equation 10 calculates these values by adding the NPSH available margin to the clean strainer suction head losses at the accident conditions and then converting the accident head loss to the equivalent loss as measured at the IST conditions, then adding the velocity head to account for the static gage measurement and converting feet to psi at the IST density. This additional test measurement was added to the IST program in response to NRC Bulletin 95-02.

Calculation M-662 has been revised (Rev. E2) to specify a fixed head loss of 2 feet to be allocated for pump in-service testing rather than calculating the remaining NPSH margin after debris is included as described above. "*Total Available Margin*" is now defined simply as the

arithmetic difference between the NPSH available and required as determined at the centerline of the pump inlet with a clean strainer. "*Available Margin for LOCA Debris*" is equal to the *Total Available Margin* minus the fixed head loss of 2 feet allocated for pump in-service testing. In addition, a description was added as to the purpose for calculating the maximum allowable suction pressure drop for In-Service Testing. The purpose of this dP_{MAX} criteria is to provide a finite, detectable change from the normal suction pressure drop that is sufficient in magnitude to be measurable by test gages. It is required that the dP_{MAX} criteria have such a basis since exceeding the limits will result in the need to take immediate action to either shut down from power operation to inspect the strainers or otherwise remedy the situation.

REFERENCES

1. GE Report GE-NE-T23-00732-01 "Containment Heat Removal Analysis", March 1996, SUDDS/RF # 96-05.
2. GE Report GE-NE-B13-01805-11 "Effects of Fiberglass Insulation Debris on Pilgrim ECCS Pump Performance", January 1996, SUDDS/RF # 96-02.
3. BECo Calculation M-662 Rev. E1 "RHR and Core Spray Pump NPSH and Suction Pressure Drop".
4. BECo Calculation S&SA-91 Rev. E0 "Containment and Decay Heat Removal Analysis Inputs".

Attachment 2

Response to NRC Request for Additional Information (RAI) dated March 13, 1997 (Enclosure 2, questions 11 through 16)

RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION (RAI) DATED MARCH 13, 1997
(ENCLOSURE 2, QUESTIONS 11 THROUGH 16)

Question 1:

Which GE code is used in the decay heat analyses?

Answer:

The decay heat portion of the heat input to the containment heat removal analysis [Ref. 1 to this attachment] was determined in accordance with GE Specification 23A6938 Rev. 1 "Decay Heat Requirements" [Ref. 2 to this attachment]. This specification gives a decay heat profile in tabular form, to be used for a full core analysis, in terms of shutdown power as a fraction of rated power (usually designated as P/Po) for increments of time after scram. The basis for the decay heat profile is ANSI/ANS 5.1 "Decay Heat Power in Light Water Reactors" [Ref. 3 to this attachment]. The sources of shutdown power (decay heat) considered are radioactive decay of fission products and actinides (heavy elements) per [Ref. 3 to this attachment] to which was added delayed neutron induced fission shutdown power. The irradiation time (effective full power days) and total exposure (megawatt-days per ton of uranium) conservatively correspond to the conditions at the end of a BWR equilibrium cycle.

The ANSI/ANS 5.1 method is readily adapted to computerized calculation. The fission product decay heat power for each of the three principal isotopes U235, U238, and Pu239 is calculated using a summation of exponential terms for each isotope, and the weighted sum is then corrected to account for neutron capture. The decay heat power for the two principal heavy elements U239 and Np239 is calculated directly and added to the fission product decay heat. An additional energy source from delayed neutron induced fission is also added to the decay heat but is not included in the ANSI/ANS 5.1 standard. This fission heat from delayed neutrons was determined by GE and is considered conservative for DBA-LOCA analysis [Ref. 4 to this attachment]. The calculation is repeated at desired intervals of time after a shutdown to generate a decay heat profile.

Question 2:

List and justify the changes in input parameters used in the ANS 5.1 decay heat curve versus those used previously in the May-Witt analyses.

Answer:

It is not possible for BECo to compare input parameters for the current decay heat analysis methods with those used for the original FSAR analysis. The Pilgrim FSAR does not explicitly define the decay heat calculation methods used. Although it has been assumed to be similar to the May-Witt method, there is no confirmation of this available to BECo. Prior to the most recent containment heat removal analyses performed by GE, a benchmark analysis was done to verify the consistency of the SHEX computer code relative to the original FSAR analysis methods. This benchmark test was performed for the limiting DBA-LOCA conditions of one

operating RHR loop. The SHEX calculation was performed using a May-Witt decay heat curve and with all other input parameters set to their original values, including a 65°F ultimate heat sink (UHS). The resulting suppression pool peak temperature was 174.4°F versus the original FSAR value of 166°F. These results indicate that a current analysis using a May-Witt decay heat profile would be significantly more conservative than the original analysis.

The current analysis performed with a 75°F UHS using the ANSI/ANS 5.1 decay heat includes many differences in input parameters compared to the original analysis. These differences are contained in both the heat input parameters, of which decay heat is a major component, and the heat removal assumptions. Other heat input sources are sensible heat stored in reactor fuel and reactor structural material, feedwater flow enthalpy addition, and metal-water reaction energy. The heat removal assumptions are based on the operation and performance of the salt service water (SSW), reactor building closed cooling water (RBCCW), and residual heat removal (RHR) systems.

If all assumptions, including those for decay heat, used in the original FSAR DBA-LOCA analysis were maintained equal, and only the UHS temperature was changed 10°F (from 65°F to 75°F), then it would be expected that the peak suppression pool temperature would increase from 166°F by 10°F or less to a new peak of approximately 176°F. The new GE DBA-LOCA analysis [Ref. 1 to this attachment], using a 75°F UHS, resulted in a peak suppression pool temperature of 178°F. Considering all these factors, it was BECo's conclusion that the new analysis is conservative in comparison to the original FSAR analysis. It is acknowledged that some inputs, such as decay heat, were changed to a value that may be individually less conservative than that used in the original analysis. However, the overall analysis methodology and the full set of input assumptions taken together yield a more conservative result.

Question 3:

Provide and justify the values for the following ANS 5.1 input parameters:

a. Q (total recoverable energy) (MeV/fission)
b. dQ (one standard deviation of recoverable energy, Q) (MeV/fission)
c. P (total power from fissioning of one nuclide) (MeV/sec)
d. dP (one standard deviation of power, P, from fissioning of nuclide) (MeV/sec)
e. Fractional fission product power for: U235, U238, Pu239 and Pu241
f. R-factor (the actinide production multiplier)
g. G-factor (a decay heat multiplier to account for the effect of neutron capture in fission products)
h. Si (a multiplier applied to the G-factor equation) (fissions per initial fissile atom)
i. Power history (length of full-power operation before shutdown).

Answer:

a. The total net energy released per fission Q, including fission energy from all fissioning nuclides per their fractional contributions plus the energy produced by non-fission neutron capture, is specified to be 207.3 MeV/fission for the core average exposure at the end of an equilibrium cycle [Ref. 4 to this attachment]. This value is based on calculations of fission energy release as a function of fuel type and exposure and the contributions from the three most significant isotopes U235, U238, and Pu239. The earlier ANS 5 standard (1971 and 1973) was based on a more arbitrary value of 200 MeV/fission and included only one decay heat curve for "uranium-fueled thermal reactors" assuming infinite irradiation. This and other methods used previously were simplistic and ignored the various components of the total decay heat that vary with the fuel operating history which

   were assumed to be included within the appropriately large uncertainties that were adopted. The analyses that provide the basis for the currently specified values for Q and R-factor (described later) include the effects from fuel exposure, the individual contributions from the principal isotopes, non-fission neutron capture, and fuel enrichment.

b. Since the value of Q was determined as a function of the core average fuel exposure and other factors that significantly influence Q as described above, the shutdown power calculations were done without an added uncertainty value for Q (ΔQ = zero). Lower values for Q are more conservative, (i.e., result in higher shutdown power levels), but Q increases with fuel exposure (MWD/ton). For the exposure and irradiation times used, which maximize overall decay heat potential, the fixed Q value used is sufficiently conservative.

c. When the final decay heat results are expressed in terms of the shutdown power ratio P/Po by dividing the operating power by Q (average energy per fission prior to shutdown), then the P term is not assigned its corresponding value in MeV/sec. That is, since the decay heat is to be expressed as the fraction (versus time after shutdown) of the constant operating power before shutdown, the decay heat profile is also a dimensionless ratio P/Po. To obtain the decay heat in Btu/hr, the ratio is multiplied by the full core operating power which was assumed to be constant at 102% of rated for the total irradiation time prior to shutdown.

d. The uncertainty ΔP MeV/sec in the total power from fissioning of each nuclide during reactor operation is effectively 2% since the total reactor power P is assumed to be a constant 102% of rated during the entire operating period prior to shutdown. In the formulation for decay heat power $P_d(t,T)$, the fission product decay heat per nuclide $f_i(t,T)$ is used without added uncertainty; that is, $\Delta f_i(t,T)$ = zero MeV/sec/fission.

e. The isotopic fission fractions vary with the fuel exposure with a pronounced shift from U235 to Pu239 as the MWD/ton exposure increases. The assumptions on fractional composition are inherently included in the Q value used which also varies with exposure. The average energy per fission is calculated by weighting the energy released for each isotope Q_i by its fractional contribution to total fissions during reactor operation. The

decay heat power from fission products is also calculated by weighting the energy released for each isotope $f_i(t)$ by its fractional contribution to total fission product decay heat power based on the isotopic fractions present just prior to reactor shutdown at the end of an equilibrium cycle of conservatively long duration.

The isotopic fission fractions are also a function of fuel enrichment where lower enrichments have a greater portion of the fissions occurring in Pu239. Higher fuel enrichment also slightly lowers the value of the energy release per fission Q and affects the value for the actinide R-factor (see below). The higher the enrichment, the smaller the value will be for the R-factor, causing the actinide contribution to decay heat to decrease. These two effects tend to cancel each other with the result that total decay heat is nearly independent of fuel enrichment [Ref. 4 to this attachment]. Based on this significant observation, the decay heat calculations are done for fuel with an average enrichment of 2.5%, and these results are valid for all the fuel enrichments actually used.

Although the total decay heat does not vary with enrichment, the isotopic fractions and R-factor do vary; therefore, the values of these parameters given for 2.5% enriched fuel are representative values only. In addition, since these parameters vary with fuel exposure, the values given correspond to core average values, and individual fuel bundles will vary significantly from the average since the core contains different batches of fuel spanning a wide range of exposures at any one time. For the core average total exposure assumed (25,700 MWD/ton), the isotopic fission fractions for fuel with 2.5% enrichment are distributed as follows [Ref. 4 to this attachment]:

Isotope	Percent of Total Fission Rate
U235	29.6
Pu239	61.6
U238	8.8

The fission product decay heat is only calculated for the U235, U238, and Pu239 isotopes. Therefore, the Pu241 isotope fraction is added to Pu239 because of the similarity between the two isotopes which are assumed to have similar fission product characteristics. This is conservative since the energy per fission for Pu241 is higher than for Pu239.

f. For the core average total exposure assumed (25,700 MWD/ton) and fuel with 2.5% enrichment, the R-factor = 0.76 [Ref. 4 to this attachment].

g. The G-factor multiplier for the decay heat power accounts for the effect of neutron capture in the fission products and is a function of the total exposure, irradiation time, and time after shutdown. The G-factor was calculated per ANSI/ANS 5.1 for shutdown times $t < 10^4$ seconds and taken directly from the $G_{max}(t)$ tabulated values in the standard for times after shutdown beyond 10^4 seconds. These G-factors are conservative since they are based on the assumed irradiation time of 3.4 years for the calculated values and 4 years for the $G_{max}(t)$ tabulated values.

h. The Si coefficient (ψ) is a function of the total exposure and is used in the calculation of the G-factors for shutdown times $t < 10^4$. The ψ coefficient increases with fuel MWD/ton exposure and achieves a value of 1.0 at between 20,000 and 30,000 MWD/ton exposure [Ref. 5 to this attachment]. A value of $\psi = 1.0$ was used for the calculated G-factors for shutdown times $t < 10^4$ seconds. For the $G_{max}(t)$ values tabulated in ANSI/ANS 5.1, the ψ coefficient is not given as a separate parameter.

i. Shutdown power is based on a fuel total exposure of 25,700 MWD/ton and an irradiation time of 1,253 effective full power days (3.4 years) prior to the reactor shutdown. These correspond to the core average values based on the batch fractions and effective full power days of operation for the four different exposure groups of fuel comprising the core (i.e., the groups operating for 1, 2, 3, or 4 cycles).

Question 4:

Specify how the length of time at full power operation before shutdown was estimated, and confirm that this value is 3.4 years, as specified in GE Report GE-NE-T23-00732-01, "Pilgrim Nuclear Power Station Containment Heat Removal Analysis," March 1996.

Answer:

The length of time at full power operation is 1,253 effective full power days (3.4 years) prior to the reactor scram. This is based on the batch fractions and effective full power days (EFPD's) of operation for the four different exposure batches of fuel comprising the core. The actual operating times for a single cycle have historically been on the order of 500 EFPD's. The upper bounding value for future operating cycles of nominal 24 month duration is 690 EFPD's. Between operating cycles, there is a refueling outage in which approximately 28% of the core is permanently discharged as spent fuel. Therefore, the number of continuous EFPD's for the core at the end of an operating cycle will not exceed 690, while the accumulated number of core average EFPD's may approach a bounding value of approximately 1,600 for the entire equilibrium core power history including periods of shutdowns and reduced power operation. The value of 1,253 EFPD's for continuous reactor operation at full power prior to a shutdown is, therefore, conservative for a BWR. The decay heat production for reactor equilibrium cycles is also known to approach its potential maximum value after about 800 days of continuous full power operation.

Question 5:

Were the contributions to the total decay heat from U-239 and Np-239 calculated in accordance with Branch Technical Position ASB 9-2? If not, provide the equation used to calculate them, and comment on the differences between it and the models given in position ASB 9-2.

Answer:

The contributions to the total decay heat from the actinides (heavy elements) U-239 and Np-239 were calculated in accordance with ANSI/ANS 5.1. However, the ANSI/ANS 5.1 and ASB 9-2 methods are essentially identical for calculating actinide decay heat. The following values are used.

Decay Energy:	E_{U239}	= 0.474 MeV/disintegration
	E_{Np239}	= 0.419 MeV/disintegration
Decay Constant:	U239	= 4.91 x10^{-4} sec^{-1} = λ_1
	[illegible]239	= 3.41 x10^{-6} sec^{-1} = λ_2

The equations for [illegible](t,T) in ANSI/ANS 5.1 are equivalent to the equations for P/Po in ASB 9-2 for U239 and Np239 when expressed as follows:

$$\frac{P(U239)}{Po} = \left(\frac{E_{U239}}{Q}\right) R\left[1 - \exp(-\lambda_1 T)\right]\exp(-\lambda_1 t)$$

$$\frac{P(Np239)}{Po} = \left(\frac{E_{Np239}}{Q}\right) R\left\{\begin{array}{l} 1.007\left[1 - \exp(-\lambda_2 T)\right]\exp(-\lambda_2 t) \\ -0.007\left[1 - \exp(-\lambda_1 T)\right]\exp(-\lambda_1 t) \end{array}\right\}$$

T	=	Total reactor operating time (seconds)
t	=	Time after shutdown (seconds)
Q	=	Total net energy released per fission = 207.3 MeV/fission

Question 6:

Justify that your use of the ANS 5.1 model for decay heat is conservative by showing that at least two standard deviations of confidence in your analyses results is provided.

Answer:

The ANSI/ANS 5.1 method for calculating decay heat requires input values for the fuel total exposure, irradiation time, enrichment, rated power, the total energy per fission Q, and the actinide production R-factor. The method determines the decay heat power after shutdown for the fission product isotopes, corrects for the effect of neutron capture in fission products, and adds the decay heat from the heavy elements (actinides). The fission product decay heat is determined for the three principal isotopes U235, U238, and Pu239 with the contribution from all other isotopes included within these three. The calculation of fission product decay heat power for each isotope $f_i(t)$ may also have an uncertainty factor applied to account for the

statistical variability of the experimental data. It may be appropriate to include this added uncertainty when the decay heat power is to be used to evaluate core cooling to determine fuel peak clad temperature (PCT) for a DBA-LOCA. For core cooling, the variation of decay heat power between fuel bundles is important, and the highest potential power level on a localized basis must be determined to find the maximum possible PCT.

The considerations for the DBA-LOCA containment heat removal analysis are somewhat different than for a core cooling analysis. For the containment analysis, all decay heat parameters are expressed as normalized core average values. The reactor core is modeled as a single bulk heat source in containment, and the heat transfer considerations are all long term relative to the point of peak fuel clad temperature which occurs very early in the event. Use of the calculated fission product decay heat power directly in terms of the core average value for this type of long term analysis is consistent with the overall modeling approach which assumes uniform mixing of the fluids in the reactor vessel and throughout the containment. This is based on the assumption that statistical variations between actual bundles may affect local power levels but not the core-wide average. It is concluded that the ANSI/ANS 5.1 method provides an accurate value for the core average fission product decay heat when appropriate conservatism is included in the assumptions for fuel exposure, irradiation time, reactor operating power level, total energy per fission Q, and the G-factor to account for neutron capture.

The decay heat contribution from the actinides (U239 and Np239) is calculated per ANSI/ANS 5.1 based on given values for the average decay energy per atom (MeV), the decay constant, and the assumed value for the actinide production factor (R-factor). The R-factor increases with fuel exposure, and the value used is conservative based on the exposures assumed. Therefore, no additional uncertainty is added to the decay heat from actinide decay.

The statistical certainty of the overall total decay heat profile is difficult to quantify since each input parameter and assumption involves a different level of conservatism and uncertainty. The only parameter for which a strictly statistical approach is used is the fission product decay power for the individual isotopes U235, U238, and Pu239 where the standard deviation is given. When all input parameters and assumptions are chosen with appropriate conservatism for a long term containment heat removal analysis, the total decay heat determined is sufficiently conservative without specifying two standard deviations of confidence for the isotopic fission product decay terms.

Also, since decay heat is only one parameter in the containment heat removal analysis, it is necessary to consider the overall method to be used. The modeling of the reactor and containment and the other sensible heat addition sources are also conservatively specified. The heat removal part of the analysis consists of specifications for pump and heat exchanger performance that are known to significantly underestimate the abilities of these systems to transfer heat from the suppression pool to the ultimate heat sink (UHS). The peak suppression pool temperature is dependent on a balance between the heat additions and cooling capacities. While the design margins for the heat removal systems are quantifiable and controllable, an increase in decay heat sources due solely to added uncertainty decreases the available margin arbitrarily.

It is also noteworthy to compare the uses of a core cooling analysis to determine PCT versus a containment heat removal analysis. The core cooling analysis must verify that the engineered safety systems, upon automatic initiation, will maintain adequate PCT during and after the core reflooding. The containment analysis considers long term heat removal and is based on many assumptions regarding operator actions as well as heat transfer equipment performance. As such, it is important that this analysis predict the potential consequences of the DBA-LOCA with an appropriate, but not arbitrary, level of conservatism.

For Pilgrim, a benchmarking approach was used to evaluate the current methods relative to the original FSAR analysis for the DBA-LOCA. As described earlier (question #2), the current analysis includes significant changes from the original FSAR analysis. However, if all assumptions, including those for decay heat, used in the original FSAR DBA-LOCA analysis were maintained equal, and only the UHS temperature was changed 10°F from 65°F to 75°F, then it would be expected that the peak suppression pool temperature would increase from 166°F by 10°F or less to a new peak of approximately 176°F. The new GE DBA-LOCA analysis, using a 75°F UHS, resulted in a peak suppression pool temperature of 178°F.

Other factors that contribute to the overall conservatism of this analysis are tabulated in Table 1 located at the end of this attachment. These factors contribute to the overall conservatism by increasing the heat addition to the containment or decreasing the heat removal achieved by containment cooling and other heat loss mechanisms.

Considering all these factors, it was BECo's conclusion that the new analysis that used a nominal decay heat is conservative in comparison to the original FSAR analysis.

An analysis of the DBA-LOCA with 2σ uncertainty added to the decay heat will result in a more rapid containment heatup and higher peak suppression pool temperature than resulted from the analysis discussed in SE 2983 which was based on the nominal decay heat described above. The peak suppression pool temperature resulting from the DBA-LOCA with 2σ uncertainty added to the decay heat will be less than 185°F which is 7°F higher than the 178°F peak pool temperature resulting from analysis that used a nominal decay heat without uncertainty added. This estimate of 185°F was calculated by adding to the suppression pool temperature for the nominal decay heat case (i.e., 178°F) the temperature change resulting from the additional decay heat energy from the 2σ uncertainty adder. That is, the additional decay heat energy due to the 2σ adder was integrated over finite time increments and then added to the suppression pool water to increase its temperature. No accounting was made of the higher heat removal rates (due to the higher temperature across the RHR heat exchanger) that will occur between the time of containment cooling initiation and the time that the peak suppression pool temperature occurs at approximately 20,000 seconds. No accounting is made of the portion of the additional energy that will be stored elsewhere inside the containment, to be removed later in the cooldown. All of the additional energy from the 2σ uncertainty adder between 0 to 20,000 seconds is assumed to be present in the suppression pool at 20,000 seconds, thereby, raising the suppression pool temperature to a conservative estimated maximum of 185°F. Figure 1 illustrates the pool temperature response calculated using the method described above.

The estimated suppression pool temperature of 185°F (based on a UHS temperature of 75°F and decay heat ANS 5.1-1979 + 2σ) is 19 degrees higher than the original licensing basis value of 166°F (based on a UHS temperature of 65°F). This peak suppression pool temperature of 185°F is well within the containment design temperature limit of 281°F and is a very conservative estimate considering that the ultimate heat sink temperature is increased only ten degree's from the original analysis.

A suppression pool temperature of 185°F will require containment overpressure to meet ECCS NPSH requirements with a clean strainer and/or the small additional head loss resulting from insulation debris. BECo installed large capacity stacked disc pump suction strainers for both the core spray and RHR pumps during the last refueling outage (RFO # 11). The current licensing basis debris-related head loss resulting from fibrous insulation is negligible because of the large surface area of the new strainers. Furthermore, BECo cleaned accumulated debris consisting of sludge and corrosion particles from the suppression pool during RFO # 11. Each of these measures, the new stacked disc strainers, and suppression pool cleaning substantially reduce and limit the potential degradation of ECCS pump suction conditions.

With regard to NPSH, the following information provides the basis for BECo's request for approval to credit the following amounts of containment pressure when evaluating ECCS pumps NPSH:

Time After Accident	Containment Pressure (psig)
0 to 600 sec.	0
600 to 6000 sec	1.9
6000 sec. to 5 days	2.5

The requested values of containment pressure take into consideration a peak suppression pool temperature of 185°F, the current licensing basis debris volume and head loss across the new stacked disc strainers, and the expectation that within 5 days the containment pressure will be returned to one atmosphere by a combination of containment cooling and leakage of noncondensible gases from the containment. The requested values of containment pressure will ensure that NPSH requirements are met for all postulated single failures including a LPCI loop select logic failure that results in four LPCI pumps injecting into the broken recirculation loop.

NPSHA is defined by the following terms:

Eq. 1 $$NPSHA = (Pc - Pvp)\frac{\left(144\frac{in^2}{ft^2}\right)}{\rho} + H_z - H_{sl} - Hdebris$$

Where:

Hz	*Elevation of suppression pool water surface above the pump inlet, ft*
Hsl	*Suction line losses, ft*
Hdebris	*Head loss from debris, ft*

NPSHA	*Net positive suction head available, feet*
NPSHR	*Net positive suction head required, feet*
Pc	*Pressure of primary containment, psia*
Pc Req'd	*Pressure of primary containment required to provide NPSHR, psia*
Pvp	*Vapor pressure at pool temperature, psia*
ρ	*Density of water in pool, lb/ft*^{3}

The containment pressure required to provide adequate NPSH is derived using Equation 1 by letting NPSHA equal NPSHR and solving for the containment pressure *Pc*. When NPSHA equals NPSHR, the containment pressure is by definition equal to the required containment pressure *Pc Req'd*.

Eq. 2

$$Pc\ Req'd = Pvp + \left(NPSHR - Hz + Hsl + Hdebris\right)\frac{\rho}{\left(144\frac{in^2}{ft^2}\right)}$$

The following input parameters are used in Eq. 2 to calculate the pressure required to provide adequate NPSH of 1.62 psig which is based on the core spray pump(s) NPSH requirement:

Input Parameter	RHR Pump	Core Spray Pump
Hz (ft)	12.5	12.5
Hsl (ft)	2.62	2.38
Hdebris (ft)	0.01	0.01
NPSHR (ft)	23	29
Pvp (psia) @ 185°F	8.386	8.386
ρ *of pumped fluid (lb/ft3) @ 185°F*	60.456	60.456
Pc Req'd for pump with maximum debris on suction strainer (psig)	-0.8 (13.896 psia)	1.62

Based on the above equations and calculation, a minimum of 1.62 psig is required to provide adequate NPSH at the estimated peak suppression pool temperature of 185°F.

In the additional question provided in (Enclosure 3 of the March 13, 1997, NRC RAI), the NRC questioned the use and purpose of Equation 10 in BECo calculation M662. Attachment 1 contains a response to this question stating that the purpose of this dP_{MAX} criteria is to provide a finite, detectable change from the normal suction pressure drop that is sufficient in magnitude to be measurable by test gages. It is required that the dP_{MAX} criteria have such a basis since exceeding the limits will result in the need to take immediate action to either shut down from power operation to inspect the strainers or otherwise remedy the situation. BECo proposes to add two (2) feet of additional head loss to the clean strainer suction line loss term (*Hsl*) to account for instrument reading variations during monthly IST test measurements of the suction line loss.

The following input parameters are used in Eq. 2 to calculate the pressure required to provide adequate NPSH of 2.46 psig which is based on the core spray pump(s) NPSH requirement. Note that *Hsl* is increased by two feet, and all other input values are unchanged from the previous calculation.

Input Parameter	RHR Pump	Core Spray Pump
Hz (ft)	12.5	12.5
Hsl (ft)	4.62	4.38
Hdebris (ft)	0.01	0.01
NPSHR (ft)	23	29
Pvp (psia) @ 185°F	8.386	8.386
ρ of pumped fluid (lb/ft3) @ 185°F	60.456	60.456
Pc Req'd for pump with maximum debris on suction strainer (psig)	0.04	2.46 Rounded to 2.5 psig

BECo previously requested that the NRC approve the analysis described in FSAR section 14.5.3.1.3 and illustrated on FSAR Figures 14.5-9 through 10, Figure 14.5-13, and Figures 14.5-18 through 19. The analysis described in the FSAR represents a lower bound estimate of the containment pressure available following a DBA-LOCA.

Figure 2 in this response, compares the requested values of containment pressure as a function of time against the containment pressure available assuming 5% leakage of noncondensible gas as illustrated on FSAR Figure 14.5-18. Also included on this figure is pressure required for the limiting ECCS pump(s) which is the core spray pump. However, the pressure required curve for the core spray pump is slightly higher than that shown on FSAR Figure 14.5-18 because the suction line loss was increased by 2 feet to accommodate IST measurement variations, and the pressure required to compensate for debris related head loss of .01 feet was included. As the figure illustrates, the pressure requested is less than that which will be available and greater than that which will be required.

Also included on Figure 2 is the estimated containment pressure available based on the ANS 5.1-1979 decay heat plus a 2 sigma uncertainty adder. The peak pressure available corresponds to the peak suppression pool temperature discussed previously in this response of 185°F. The estimated peak pressure required of 2.46 psig also corresponds with the estimated peak suppression pool temperature of 185°F.

Based on the above NPSH evaluation, BECo requests approval to credit the following amounts of containment overpressure when evaluating ECCS pump NPSH for the limiting DBA-LOCA event:

Time After Accident	Containment Pressure (psig)
0 to 600 sec.	0
600 to 6000 sec.	1.9
6000 sec. to 5 days	2.5

REFERENCES

1. GE Report GE-NE-T23-00732-01 "Containment Heat Removal Analysis", March 1996, SUDDS/RF # 96-05.

2. GE Specification 23A6938 Rev. 1 "Decay Heat Requirements", June 1992.

3. ANSI/ANS 5.1-1979 "Decay Heat Power in Light Water Reactors", August 1979.

4. GE NEDO-23729 "Nuclear Basis for ECCS (Appendix K) Calculations", November 1977.

5. GE NEDC-23785P "The GESTR-LOCA and SAFER Models for the Evaluation of Loss-of-Coolant Accident", October 1984.

Figure 1 - Comparison of DBA-LOCA Suppression Pool Temperature Response for Different Decay Heat Inputs

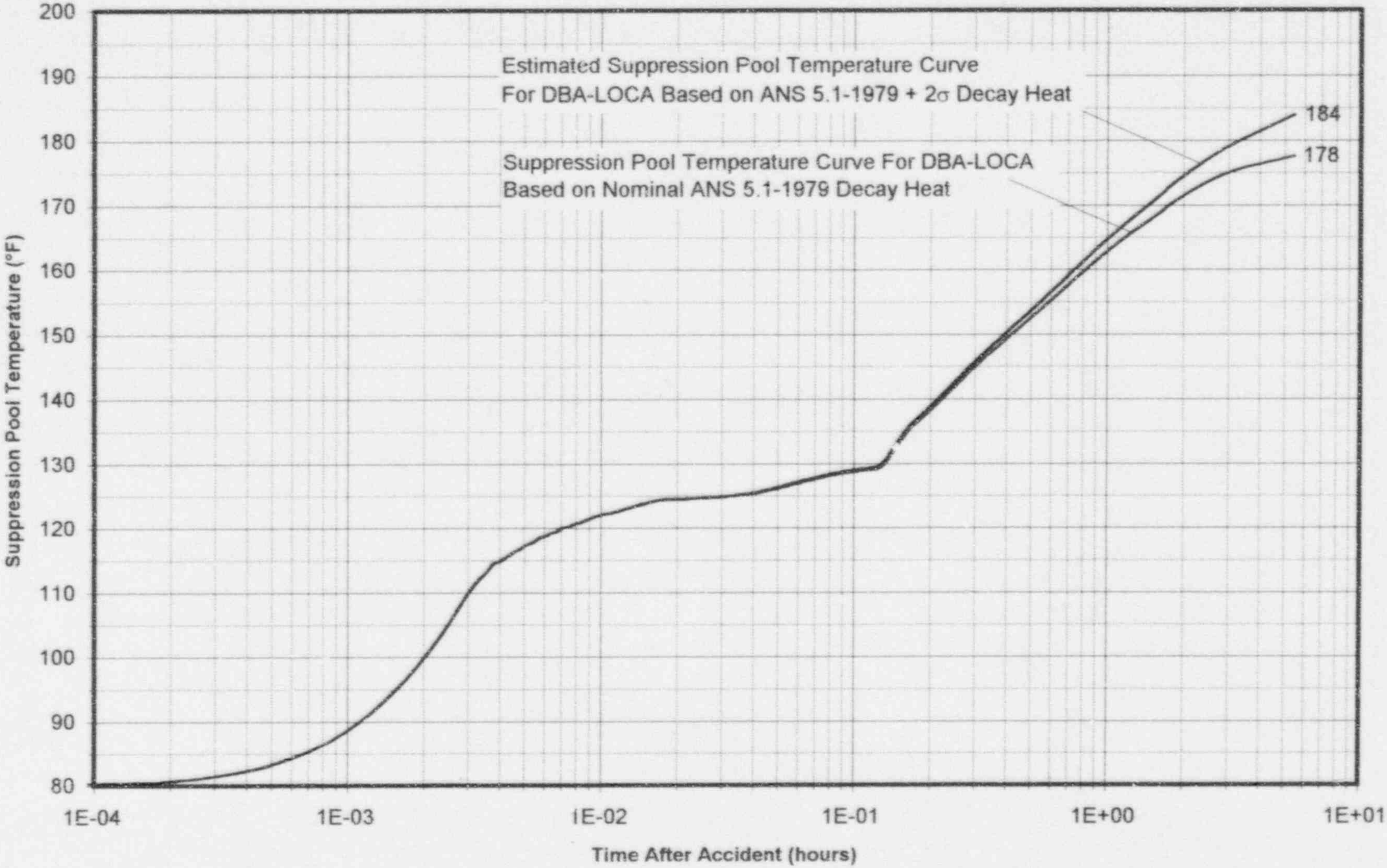
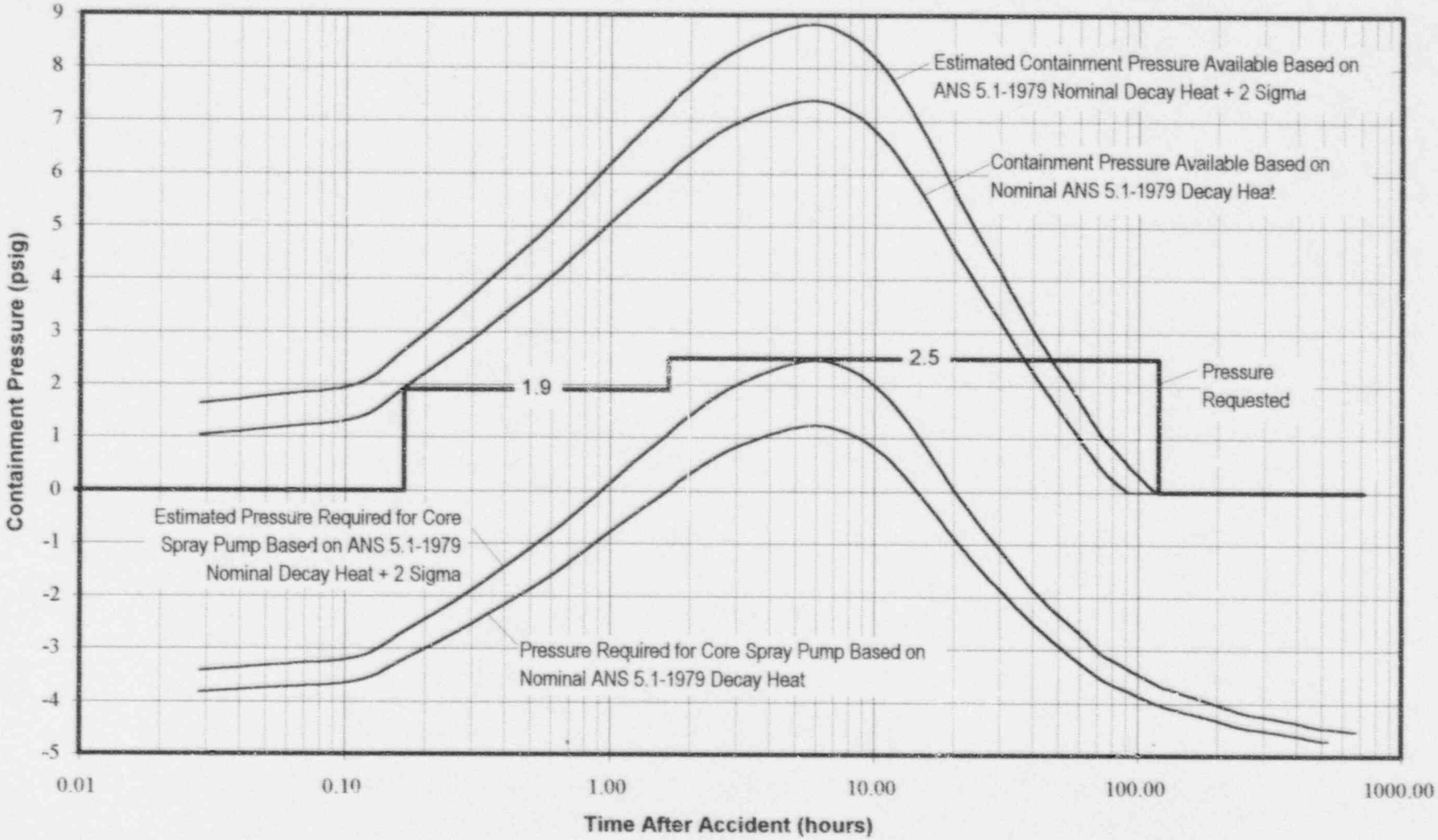


Figure 2 - Comparison of Requested Pressure to Containment Pressure Available and Containment Pressure Required



Note: Curves are based on a 75°F ultimate heat sink temperature, and pressure required curves include a 2 foot additional suction line loss to accommodate IST measurement variation, and a 0.01 foot debris related head loss.

Table 1

Parameter	Original Licensing Basis DBA-LOCA	DBA-LOCA Analysis SE2983	Two-Sigma DBA-LOCA Analysis
Decay Heat	Undocumented in licensing basis. May-Witt used for benchmark analysis.	ANS 5.1-1979 without uncertainty	ANS 5.1-1979 with two sigma uncertainty
Initial power level	100%	102%	102%
Feedwater Input	Minimized to limit vessel depressurization from colder feedwater which will lower the peak short-term containment pressure.	This is a long-term heat up analysis, so feedwater addition was continued while the feedwater enthalpy contributes to suppression pool heatup. This treatment maximizes suppression pool temperature and the secondary peak pressure.	This is a long-term heat up analysis, so feedwater addition was continued while the feedwater enthalpy contributes to suppression pool heatup. This treatment maximizes suppression pool temperature and the secondary peak pressure.
Reactor Vessel Conditions	Saturated	Saturated	Saturated
Torus water level	Technical Specification minimum	Technical Specification minimum	Technical Specification minimum
ECCS pump heat addition	None	Rated horsepower is added when pump(s) are operating	Rated horsepower is added when pump(s) are operating
Heat loss from containment	Containment is assumed to be perfectly insulated, heat removed only via the RHR heat exchanger	Containment is assumed to be perfectly insulated, heat removed only via the RHR heat exchanger	Containment is assumed to be perfectly insulated, heat removed only via the RHR heat exchanger
Internal heat sinks	Not included	Not included	Not included
Heat exchanger Performance	Based on original heat exchanger ratings at rated flow conditions and design fouling.	Based on heat exchanger performance at system minimum flow rates and maximum allowable fouling/tube plugging that are design basis for in-service performance testing for pumps and heat exchangers.	Based on heat exchanger performance at system minimum flow rates and maximum allowable fouling/tube plugging that are design basis for in-service performance testing for pumps and heat exchangers.
Containment Cooling Initiation Time and Flows	at 600 seconds with 5000 gpm through the RHR heat exchanger	at 600 seconds with 3430 gpm, switching to 5100 gpm at 2 hours.	at 600 seconds with 3430 gpm, switching to 5100 gpm at 2 hours.
Service Water inlet Temperature	Constant 65°F	Constant 75°F for 30 days. No accounting for temperature variations from the diurnal cycle and tidal effects.	Constant 75°F for 30 days. No accounting for temperature variations from diurnal cycle and tidal effects.

Table 1 Continued...
Key Results

Parameter	Original Licensing Basis DBA-LOCA	DBA-LOCA Analysis SE2983	Two-Sigma DBA-LOCA Analysis
Peak Suppression Pool Temperature	166°F	178°F	Estimated at 185°F
Secondary Peak Containment Pressure	8.0 psig	9.7 psig	Estimated at 10.9 psig
Time of Occurrence for Peak Suppression Pool Temperature and Secondary Pressure	5.5 hours	5.5 hours	Estimated at 5.5 hours. Should occur earlier with a higher decay heat source.

Attachment 3

Response to NRC Request for Additional Information (RAI) dated March 31, 1997 (Enclosure questions 1 through 11)

RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION (RAI) DATED MARCH 31, 1997
(ENCLOSURE QUESTIONS 1 THROUGH 11)

Question 1a:

> *Page 32 of Safety Evaluation No. 2983 indicates that the EQ analysis differs from the FSAR analysis in two respects: (1) The EQ analysis takes credit for passive heat sinks in the drywell, wetwell, and suppression pool which tend to moderate the drywell temperature response, and (2) the EQ analysis takes credit for a 720 vs. 300 drywell spray flow which provides more cooling to the drywell airspace and reduced temperature for equipment located in the drywell. Page 32 also indicates that a review and update of all environmental qualification data files was performed to verify environmental qualification at the new 75°F qualification envelop for drywell temperature. It is not clear if the 75°F qualification envelop for drywell temperature is based on the EQ or FSAR analysis described above. Provide clarification.*

Answer:

The equipment qualification (EQ) envelope for drywell temperature is based on the EQ analysis described in Section G.7(a), Page 32-33 of SE2983. The current EQ analysis uses a drywell spray flow rate of 720 gpm and credits passive heat sinks inside the containment. The EQ analysis will be revised to reflect both the 2σ adder to the decay heat and a hardware modification completed during RFO # 11 that increased drywell spray flowrate.

The EQ drywell temperature envelope is a composite curve that presents drywell temperature as function of time. A composite curve envelope represents a more demanding qualification requirement for equipment because it bounds the drywell temperature from a spectrum of steam line breaks ranging in size from 0.01 ft^2 to 1.0 ft^2 rather than bounding a single break size. This composite curve approach is used to summarize the qualification requirements with respect to temperature for all steam line breaks on a single curve and thereby minimize the number of temperature curves that need to be reviewed or evaluated during qualification.

The steamline break analysis evaluated in SE2983 is based on a nominal decay heat calculated using ANS 5.1-1979. Higher drywell temperatures would be expected from an increase in the decay heat input to the steamline break analysis.

In discussions with the NRC pertaining to this license amendment request, the NRC reviewers has expressed the position that the decay heat input to containment analysis should include additional decay heat energy to raise the total decay heat above a 95% confidence level. To meet this level of confidence, two standard deviations would be added to the nominal decay heat energy. To counteract the drywell temperature increase that will result from the addition of two standard deviations to the overall decay heat, the drywell spray flow rate was increased during RFO # 11 to a minimum design value of 1250 gpm from the previous design value of 720 gpm. To achieve this increase in drywell spray flowrate, additional nozzles located on the upper and lower drywell spray headers were uncapped and replaced with spray nozzle assemblies. This increase in the drywell spray flowrate of greater than 70% was selected to completely offset the drywell temperature increase that would otherwise result from the ANS

5.1-1979 + 2σ decay heat and provide a lower drywell temperature response profile than that currently used for equipment qualification.

The FSAR steam line break analysis referred to in Section G.7(a) is evaluated in Section G.2(b)(2) on Page 22 of SE2983. The primary purpose of the FSAR steam line break analysis is to demonstrate that drywell spray has sufficient cooling capacity to reduce the drywell atmosphere temperature below the containment liner design temperature of 281°F and control the drywell atmosphere temperature below 281°F throughout the primary system and containment cooldown. The FSAR steam line break analysis is discussed in FSAR Section 5.2.3.2 and illustrated on FSAR Figures 5.2-2 through 5.2-6. This analysis uses a drywell spray flow rate of 300 gpm and takes no credit for passive heat sinks inside the containment.

Question 1b:

Clarify what is meant by "equipment qualification was verified".

Answer:

We reviewed our existing EQ documentation to ensure that all EQ components located in the drywell are qualified to the new composite profile. The EQ documentation was then updated to demonstrate continued compliance with 10CFR50.49 requirements.

Questions 1.b.1:

Is equipment qualified to the requirements of Paragraph (e) of 10CFR50.49? If not, provide justification and describe how equipment has been qualified.

Answer:

The EQ Master List lists all components requiring EQ and whether the equipment is qualified to 10CFR50.49 or NRC Division of Operating Reactors (DOR) Guidelines. PNPS was licensed prior to the issuance of 10CFR50.49 in January 1983 and, therefore, fell under DOR guidelines for environmental qualification. Of the 105 components requiring qualification for service in the drywell, 65 are qualified to 10CFR50.49 requirements and 40 are qualified to DOR requirements. The files for all components that are required to be qualified to 10CFR50.49 were reviewed to ensure that they are qualified to the requirements stated in Paragraph (e) of 10CFR50.49. The components that are qualified to DOR are further discussed below.

Questions 1.b.1.a:

For equipment qualified using methods permitted by Paragraph (k) of 10CFR50.49 (i.e., DOR guidelines - no aging required), describe and provide justification for the process used to assure each item of electric equipment important to safety covered by 10CFR50.49 will meet its specified performance requirements when it is subjected to the conditions predicted to be present when it must perform its safety function up to the end of its qualified life (Ref. Paragraph (j) of 10CFR50.49).

Answer:

The justification for not qualifying the following components located in the drywell in accordance with 10CFR50.49 is that they are qualified in accordance with DOR guidelines. The component identification and qualification method follows:

Component	***Qualification Method***
Cable code 112 - Okonite	Sequential testing
Cable code 512 - Okonite	Sequential testing
Cable code 912 - Kerite	Sequential testing
Component	***Qualification Method***
Cable code 312 - Kerite	Sequential testing
Cable code 312 - Okonite	Sequential testing
Cable code 712 - Kerite	Sequential testing
Cable code 712 - Okonite	Sequential testing
Cable code B7 - Kerite	Sequential testing
Cable code B8 - Kerite	Sequential testing
MO1001-50	Combined test & analysis
MO1201-2	Combined test & analysis
MO1301-16	Combined test & analysis
MO202-5A	Combined test & analysis
MO202-5B	Combined test & analysis
MO220-1	Combined test & analysis
MO2301-4	Combined test & analysis
ZS1001-50	Combined test & analysis
ZS1201-2	Sequential testing
ZS1301-16	Sequential testing
ZS220-1	Sequential testing
ZS2301-4	Sequential testing
Q100E	Combined test & analysis
Q101B	Combined test & analysis
Q102A	Combined test & analysis
Q102B	Combined test & analysis
Q103A	Combined test & analysis
Q103B	Combined test & analysis
Q105A	Combined test & analysis
Q105B	Combined test & analysis
Q106B	Combined test & analysis
Cable code - S1B	Combined test & analysis
Terminal Blocks for Limitorque Valve	Combined test & analysis
SV203-1A-1	Sequential testing
SV203-1A-2	Sequential testing
SV203-1B-1	Sequential testing
SV203-1B-2	Sequential testing
SV203-1C-1	Sequential testing
SV203-1C-2	Sequential testing
SV203-1D-1	Sequential testing
SV203-1D-2	Sequential testing

Question 1.b.2:

> *Do EQ test profiles (for accident and post-accident) for each piece of equipment envelop the new EQ accident and post-accident profiles? Or, if not, identify how and provide justification for each case where the EQ test profile does not envelop the new accident and post-accident profiles.*

Answer:

All EQ test profiles envelop the accident and post-accident profiles. The Arrhenius methodology has been utilized to extend post - LOCA operating time when required. In all cases, the peak accident temperature and pressure is enveloped by the peak test temperature and pressure.

The Arrhenius method is only used following the blowdown phase of the accident when the changes in temperature do not affect the appropriateness of using the Arrhenius method.

Question 1c:

> *Identify how and provide justification for each case where the EQ test profile does not envelop the new accident profile (accident and post-accident profiles) based on the FSAR analysis for establishing accident profile.*

Answer:

Existing FSAR analysis is not applicable to EQ. Please refer to response to Question 1a.

Question 2a:

> *Page 35 of SE2983 indicates equipment qualification was verified for resulting post-LOCA building ambient temperature profiles without loss of offsite power. Explain how this verification covers equipment qualification for post-LOCA building ambient temperature profiles with (versus without) loss of offsite power and with single active failure with and without loss of offsite power. Also, explain how this verification covers equipment qualification for LOCA building ambient temperature profiles with and without loss of offsite power and with single active failure. Similarly, explain how steam line breaks (i.e., other accidents besides LOCA) are covered.*

Answer:

Interpretation of Question 2a, assuming that "building" means secondary containment and that the distinction between post-LOCA and LOCA is deliberate, results in the following restatement of the questions:

2a-1. The stated post-LOCA secondary containment temperature analysis was performed assuming no Loss Of Offsite Power (LOOP). Does this bound the case where a LOOP is assumed and why?

2a-2. Discuss whether and how single active failures are addressed in the post-LOCA secondary containment temperature analysis.

2a-3. The secondary containment temperature analysis was performed for post-LOCA conditions. Does this scenario bound a LOCA and a single active failure, with and without LOOP?

2a-4. Discuss whether and how High Energy Line Breaks (HELBs) are impacted by the proposed changes.

<u>*Restated Question 2a-1*</u>

The stated post-LOCA secondary containment temperature analysis was performed assuming no Loss Of Offsite Power (LOOP). Does this bound the case where a LOOP is assumed and why?

Answer:

The post-LOCA without LOOP scenario is bounding over the post-LOCA *with* LOOP case. The post-LOCA analysis calculates the temperature transient that takes place in secondary containment due to a LOCA inside primary containment. This temperature transient occurs due to the isolation of secondary containment when the LOCA occurs. With secondary containment isolated, a single train of the standby gas treatment system (SBGT) running, safety-related unit coolers operating, and no other forced ventilation available, the internal heat loads in the building cause the temperature in the secondary containment to increase.

The primary heat loads causing this to occur consist of process piping containing ECCS fluids at elevated temperatures and resistive heat losses from electrical equipment, lighting and power cables. As a result, a loss of offsite power is not the bounding scenario since all of the non-essential equipment would not be operating, and the associated heat loads would not be present. This reduces the overall heat load in the building and results in lower long-term temperature profiles. Despite assuming the availability of offsite power, no credit was taken for non-emergency bus powered HVAC equipment.

Therefore, the PNPS post-LOCA secondary containment temperature analysis conservatively assumed no loss of offsite power in generating the temperature profiles for equipment qualification. This analysis conservatively bounds the LOCA with LOOP scenario.

<u>*Restated Question 2a-2*</u>

Discuss whether and how single active failures are addressed in the post-LOCA secondary containment temperature analysis.

Answer:

Single active failures were addressed in the post-LOCA secondary containment temperature analysis. Since the analysis is a time-dependent heat gain/heat loss problem, a single active failure will either affect the heat load in secondary containment or the heat removal from it.

A single active failure that results in the failure of equipment to operate, also results in a corresponding reduction in the building heat load from the equipment itself or the process fluid it was moving. As a result, for equipment that generates heat load in the building or pumps process fluid, it is more conservative to assume that this equipment continues to operate and does not fail. Thus, no single active failures were conservatively assumed in the identification of the building heat loads.

With respect to heat removal systems, the only systems credited in the analysis are the standby gas treatment system and the safety-related unit coolers located in the HPCI, RCIC and RHR compartments. In these cases, single active failures were assumed to disable one train of each heat removal system due to loss of an emergency diesel generator. Although we only needed to assume one single active failure, the number of analyses required to evaluate the different permutations of such a failure would have been excessive. Instead, it was conservatively decided to assume all possible single failures in one scenario, even if they were mutually exclusive. This resulted in a conservatively bounding accident scenario for the post-LOCA secondary containment heat up analysis.

Thus, single active failures were assumed only when they resulted in a more conservative analysis.

<u>*Restated Question 2a-3*</u>

The secondary containment temperature analysis was performed for post-LOCA conditions. Does this scenario bound a LOCA and a single active failure, with and without LOOP?

Answer:

Although a LOCA initiates the scenario, the affects on secondary containment are slow to occur. Significant increases in secondary containment temperatures typically occur long after vessel reflood. As a result, the analysis was described as "post-LOCA" even though the scenario starts at LOCA initiation and continues for 30 days. Thus, there was only one LOCA-related, secondary containment heat up scenario analyzed.

<u>*Restated Question 2a-4*</u>

Discuss whether and how high energy line breaks (HELBs) are impacted by the proposed changes.

Answer:

High energy line breaks (HELBs), otherwise known as pipe breaks outside containment (PBOC), are analyzed and used to develop process building temperature and pressure profiles used in the qualification of electrical equipment important to safety per 10CFR50.49. These pipe break analyses, which are described in Appendix O of the PNPS FSAR, are assumed to occur at rated conditions and are generally isolated within 60 seconds. Neither the rated conditions nor the isolation times are affected by a 75°F maximum salt service water temperature.

As described in the FSAR, the PBOC analyses assume a loss of offsite power (LOOP) to occur concurrently with the postulated failure of the high energy pipe, if it is conservative to do so. For generation of the HELB environmental temperature and pressure profiles, a LOOP was assumed to occur for most pipe breaks analyzed. Combined with an assumed single active failure of the DC powered isolation valve(s) to close, the full flow pipe break blowdown was extended in duration to account for the time required to start the emergency diesel generators and close the AC powered isolation valves.

This results in bounding worst case environmental profiles for use in environmental qualification of electrical equipment due to the extended vessel blowdown. In the case of a break in the main steam lines, the air operated, spring assisted isolation valves are unaffected by a LOOP assumption.

Thus, the HELB analyses are unaffected by a 75°F maximum salt service water temperature and re-analysis was not required.

Question 2.b:

> *Clarify what is meant by "equipment qualification was verified".*

Answer:

We reviewed the existing EQ documentation to ensure that all EQ components located in areas where the peak temperature is equal to or greater than 130°F ("harsh") due to a LOCA without LOOP are qualified to the new composite profile. The EQ documentation was then updated to demonstrate continued compliance with 10CFR50.49 requirements.

Question 2.b.(1):

> *Is equipment qualified to the requirements of Paragraph (e) of 10CFR50.49? If not, provide justification and describe how equipment has been qualified.*

Answer:

The EQ Master List lists all components requiring EQ and whether the equipment is qualified to 10CFR50.49 or NRC Division of Operating Reactors (DOR) Guidelines. PNPS was licensed prior to the issuance of 10CFR50.49 in January 1983 and, therefore, fell under DOR guidelines for environmental qualification. Of the 282 components requiring qualification, 174 are qualified to 10CFR50.49 requirements and 108 are qualified to DOR requirements. The files for all components that are required to be qualified to 10CFR50.49 were reviewed to ensure that they are qualified to the requirements stated in Paragraph (e) of 10CFR50.49. The components that are qualified to DOR are further discussed below.

The equipment ID and qualification method follows:

<u>***Equipment ID***</u>	<u>***Qualification Method***</u>
RE1001-606A	Combined Test & Analysis
RE1001-606B	Combined Test & Analysis

RE1001-607A	Combined Test & Analysis
RE1001-607B	Combined Test & Analysis
J258	Sequential Test & Analysis
J522	Sequential Test & Analysis
J523	Sequential Test & Analysis
J53	Sequential Test & Analysis
J623	Sequential Test & Analysis
J624	Sequential Test & Analysis
J625	Sequential Test & Analysis
J626	Sequential Test & Analysis
J685	Sequential Test & Analysis
MO1001-16A	Sequential Test & Analysis
MO1001-18A	Sequential Test & Analysis
MO1001-23A	Sequential Test & Analysis
MO1001-23B	Sequential Test & Analysis
MO1001-26A	Sequential Test & Analysis
MO1001-26B	Sequential Test & Analysis
MO1001-28A	Sequential Test & Analysis
MO1001-28B	Sequential Test & Analysis

Equipment ID	***Qualification Method***
MO1001-29A	Sequential Test & Analysis
MO1001-29B	Sequential Test & Analysis
MO1001-34A	Sequential Test & Analysis
MO1001-36A	Sequential Test & Analysis
MO1001-37A	Sequential Test & Analysis
MO1001-43A	Sequential Test & Analysis
MO1001-43C	Sequential Test & Analysis
MO1001-47	Sequential Test & Analysis
MO1001-60	Sequential Test & Analysis
MO1001-7A	Sequential Test & Analysis
DPT1001-604A	Sequential Test & Analysis
DPT1001-604B	Sequential Test & Analysis
MO1001-7C	Sequential Test & Analysis
MO1201-5	Sequential Test & Analysis
MO1301-17	Sequential Test & Analysis
MO1301-49	Sequential Test & Analysis
MO1400-24A	Sequential Test & Analysis
MO1400-25A	Sequential Test & Analysis
MO1400-3A	Sequential Test & Analysis
MO1400-4A	Sequential Test & Analysis
MO220-2	Sequential Test & Analysis
MO2301-5	Sequential Test & Analysis
MO2301-8	Sequential Test & Analysis
MO4002	Sequential Test & Analysis
MO4065	Sequential Test & Analysis
MO4060A	Sequential Test & Analysis
MO4060B	Sequential Test & Analysis
P203A	Sequential Test & Analysis
P203C	Sequential Test & Analysis
P215A	Sequential Test & Analysis

Q101B	Combined Test & Analysis
Q102A	Combined Test & Analysis
Q103A	Combined Test & Analysis
Q105B	Combined Test & Analysis
Q106B	Combined Test & Analysis
ZS1001-23A	Sequential Test & Analysis
ZS1001-23B	Sequential Test & Analysis
ZS1001-26A	Sequential Test & Analysis
ZS1001-26B	Sequential Test & Analysis
ZS1001-28A	Sequential Test & Analysis
ZS1001-29A	Sequential Test & Analysis
ZS1001-29B	Sequential Test & Analysis
ZS1001-34A	Sequential Test & Analysis
ZS1001-37A	Sequential Test & Analysis
ZS1001-47	Sequential Test & Analysis
ZS1201-5	Sequential Test & Analysis
ZS1201-80	Sequential Test & Analysis
ZS1301-17	Sequential Test & Analysis
ZS1301-49	Sequential Test & Analysis
Equipment ID	***Qualification Method***
ZS1400-24A	Sequential Test & Analysis
ZS1400-25A	Sequential Test & Analysis
ZS220-2	Sequential Test & Analysis
ZS2301-5	Sequential Test & Analysis
ZS2301-8	Sequential Test & Analysis
ZS4002	Sequential Test & Analysis
Cable Code 106	Sequential Testing
Cable Code 112	Sequential Testing
Cable Code 212	Sequential Testing
Cable Code 212E	Sequential Testing
Cable Code 312	Sequential Testing
Cable Code 412	Sequential Testing
Cable Code 512	Sequential Testing
Cable Code 512A	Sequential Testing
Cable Code 512B	Sequential Testing
Cable Code 712	Sequential Testing
Cable Code 712A	Sequential Testing
Cable Code 912	Sequential Testing
Cable Code A1	Sequential Testing
Cable Code A2	Sequential Testing
Cable Code B1	Sequential Testing
Cable Code B2	Sequential Testing
Cable Code B3	Sequential Testing
Cable Code B4	Sequential Testing
Cable Code B5	Sequential Testing
Cable Code B6	Sequential Testing
Cable Code B7	Sequential Testing
Cable Code B8	Sequential Testing
Cable Code B9	Sequential Testing
Cable Code C12	Sequential Testing

Cable Code CXG	Sequential Testing
Cable Code S1	Sequential Testing
Cable Code S1B	Sequential Testing
Cable Code TX1	Sequential Testing
Cable Code Z3	Sequential Testing
Cable Code Z3A	Sequential Testing
SV203-2A-1,2	Sequential Testing
SV203-2B-1,2	Sequential Testing
SV203-2C-1,2	Sequential Testing
SV203-2D-1,2	Sequential Testing

Question 2.b.(2):

Do EQ test profiles (for accident and post-accident) for each piece of equipment envelop the new EQ accident and post-accident profiles? Or, if not, identify how and provide justification for each case where the EQ test profile does not envelop the new accident and post-accident profiles.

Answer:

All EQ test profiles envelop the accident and post-accident profiles. The Arrhenius Methodology has been utilized to extend post-LOCA operating time when required. In all cases, the peak accident temperature and pressure is enveloped by the peak test temperature and pressure.

Question 3:

Page 31 of SE2983 states: "Equipment at PNPS requiring qualification to meet the requirements of 10CFR50.49 are listed in the Environmental Qualification Master List (Ref. 46)." Page 33 of SE2983 states: "The containment electrical penetrations that support the operation of active equipment are listed on the EQ Master List (Ref.46). Containment electrical penetrations not listed on the EQ Master List contain cabling that is not required to function electrically in a post-accident environment but may continue to operate. Although functionally passive, penetrations not listed on the EQ Master List must remain leaktight to ensure containment integrity. These statements appear to indicate that equipment considered functionally passive (e.g., non-safety electrical penetration) do not have to meet requirements of 10CFR50.49 but must remain leaktight to ensure containment integrity (i.e., to ensure the requirements of paragraph (b)(1)(iii) of 10CFR50.49 are met). Provide clarification. Identify other electrical equipment which have been determined to not have to meet 10CFR50.49 requirements because they are considered functionally passive.

Answer:

Equipment listed in the PNPS EQ Master List (EQML) is required to safely shut the plant down in a post accident environment and meets 10CFR50.49 requirements. Containment penetrations that house class 1E circuits are listed in the EQML. These penetrations are evaluated in a post-accident environment for the impact of the penetration on the Class 1E

circuits. The penetration will survive a post-accident environment and not adversely affect Class 1E circuits.

Equipment that is not required to operate to safely shut down the reactor post-accident, is not evaluated against the requirements of 10CFR50.49 and, therefore, is not included in the PNPS EQML. Evaluation is not required because the reactor may be safely shut down post-accident without the operation of this equipment. Failure of cables, motors, or signals will not adversely impact the ability to shut down the reactor or mitigate the consequences of an accident. This equipment may operate but is not credited for post-accident operation.

The containment penetrations that contain non-safety related cables are not evaluated, though these penetrations still must maintain containment integrity. The criteria of 10CFR50 Appendix J provide the requirements for containment penetrations post-accident. The penetrations must maintain an acceptable leakage rate at accident temperatures and pressures.

Containment penetrations are passive devices and are not necessarily evaluated to criteria in 10CFR50.49. If the penetration has cables that are required post-accident, then the penetration is also evaluated for impact on that cable. That penetration would be listed in the EQML and treated as EQ equipment. The penetration must also remain leaktight in the post-accident environment. That design criteria is specified in Appendix J and is separate from the EQ criteria.

This is not intended to mean that because a component is functionally passive it does not have to be included in the EQ program. The penetrations are qualified to separate criteria to ensure that post-accident Primary Containment leakage will be limited so the release of radioactive material below 10CFR Part 100 limits. The fact that a device is passive is not a valid reason to declare the device exempt from environmental qualification. The containment penetrations are included in the EQML and evaluated for impact on cables and other devices in the Class 1E circuit. Containment penetrations are mechanical devices and are not required to be evaluated for EQ per 10CFR50.49.

No other electrical equipment has been exempted from the requirements of 10CFR50.49 based only on the fact that it is functionally passive. Penetrations that are not included on the EQML are exempted from 10CFR50.49 because there is no EQ impact of the penetration on qualified devices.

Question 4:

> *Define the original plant accident requirements profile which had a peak temperature of 330°F to which electrical penetrations were qualified.*

Answer:

Attached (page 20 of this attachment) is the temperature versus time profile for the PNPS drywell prior to updating the profile based on the 75°F ultimate heat sink temperature analysis. This profile shows the 330°F peak temperature used in previous penetration evaluations.

SUMMARY OF PENETRATION ISSUES (Questions 5 to 11)

In summary, the environmental qualification of the PNPS primary containment electrical penetrations fall under the DOR guidelines. These guidelines do not require a specified qualified life be demonstrated for Class IE equipment installed in plants operating prior to issuance of IE Bulletin 79-01B. The General Electric test profiles, referenced in the NRC questions, were completed in the 1970 time frame. These tests were not intended and do not prove the penetrations can operate for 40 years in a normal environment and then survive the DBA. PNPS has been monitoring the penetration seals for age-related deterioration under the Local Leak Rate Test program during each RFO. To date we have not experienced a seal failure.

Based on the best data available for the penetration epoxy, BECo has evaluated the expected life of the penetration seals, using conservative ambient temperatures and worst case conductor heatup due to electrical losses and accounting for the loss of life associated with the accident high temperature and radiation. The activation energy used (1.13 eV) for this evaluation was the more conservative of two activation energies developed by General Electric, using two different TGA methods, as documented in their report NEDC-32123P. The activation energy was developed based on a 10 % weight loss even though General Electric indicates that a15 % weight loss would be acceptable. This activation energy, with other General Electric test data, indicates an expected life that is shorter than all but one epoxy resin listed in the Wyle material database. Based on the above, BECo believes that the use of the 1.13 eV activation energy to evaluate the expected life of the epoxy is reasonable. The BECo evaluation was completed for the epoxy seals on the primary containment side of the penetration. The second penetration seal, located in a lower ambient temperature in the secondary containment, will have a longer (approx. 250 years) life expectancy. General Electric has confirmed that only one seal is required to maintain containment integrity.

Question 5:

> *Provide the results of a linear slopes comparison analysis that utilizes Arrhenius methodology (similar to that shown in attachment 7 of General Electric Proprietary Document NEDC-32123P, Report PIR-CPD92045 Service Life Estimate for the Epoxy Sealant in the Penetration Assemblies at the Browns Ferry Nuclear Plant Unit 3, dated August 20, 1992) which compares the 18929.01 equivalent hours obtained for the test profile of 0.5 hours at 352°F plus 23.5 hours at 309°F plus 3 hours at 135°F to equivalent hours at the original plant accident requirements profile plus the equivalent hours for 40 years at 150°F.*

Answer:

The PNPS primary containment electrical penetrations fall under DOR Guidelines for Environmental Qualification. Paragraph 7.0 of Enclosure 4 to IE Bulletin 79-01B (DOR Guidelines) states that a specific qualified life need not be demonstrated for Class IE equipment for plants already constructed and operating. The guidelines also state ongoing programs should exist to ensure equipment that is exhibiting age-related degradation will be identified and replaced as necessary.

The General Electric F01 canister type penetrations were not aged for temperature and radiation prior to accident testing during the G. E. qualification program (c. 1970). Based on the available testing, BECo has evaluated the electrical penetrations to ensure they would be able to survive the worst case PNPS design basis accident (DBA) and have been using leak rate testing of the penetration seals to monitor the penetrations for age-related deterioration. This testing, performed at 45 psig, has not identified a seal failure.

The test profile referenced was from a General Electric test intended to prove the penetrations would survive the DBA. It was not intended to prove the penetrations could operate for 40 years in the normal environment and then survive the DBA. As such, the test profile does not envelop the 40 year of license plus PNPS DBA profile.

Prior to 1996, BECo considered the penetration epoxy to be age insensitive based on an expected life of 424 years. This expected life was calculated in 1985 using Arrhenius methodology based on what was considered to be a conservative activation energy. The activation energy used was selected based on review of data for a number of similar epoxy resins in the Wyle Laboratories material database. The epoxy activation energy was not available from General Electric at that time.

During review of the penetration Environmental Qualification report in 1996, it was determined, based on discussions with General Electric (based on GE report PIR-CPD95045), that the penetration epoxy had an activation energy of 1.13 to 1.16 ev. Using the conservative 1.13 eV activation energy, the expected life of the epoxy dropped to approximately 62.8 years at 150°F. The 150°F is based on an expected 125°F average ambient temperature at the primary containment side seals of the penetrations, plus a 25°F heat rise for the worst case continuous duty motors being supplied through the penetrations.

Based on the reduced life expectancy for the two worst case penetrations serving the continuous duty motors, BECo performed a more detailed evaluation of the epoxy to determine the life remaining after subtracting the life removed to date (based on historical data) and the life required to survive the DBA. The life required for the accident includes the impact of temperature and radiation. The life required for the DBA temperature was evaluated, along with the normal ambient, using the Arrhenius methodology. The impact due to radiation was estimated based on the percent loss of weight at different radiation levels as reported by General Electric verses the maximum radiation level expected at the PNPS penetration seals. General Electric uses a 10 percent weight loss as the acceptance criteria for the penetration epoxy.

The above evaluation (not required for DOR) and the continued pressure monitoring of both penetration seals under the Local Leak Rate Testing program at PNPS provides assurance that the penetration epoxy seals will be able to survive the DBA after an additional 36.4 years under normal conditions and / or age related deterioration. Note that the secondary containment side seal epoxy has a life expectancy of approximately 250 years at it's normal expected operating temperature verses the 62.8 years for the primary containment side seal epoxy as noted above.

Question 6:

Electric Power Research Institute's (EPRI's) Nuclear Power Plant Equipment Qualification Reference Manual indicates that the Arrhenius method has been employed to relate accident test temperatures to postulated accident temperatures. If the Arrhenius model and activation energy value are applicable to the test and accident temperatures, then the model may arguably be used in various ways to draw correlations between the accumulated thermal damage occurring during various phases of LOCA testing. This approach has been used principally to support long-term operability in post-LOCA environments when it is desirable to have a test duration be shorter than the actual required operability time. For example, the test temperature plateau dropped to 212°F at 5 days into the 30-day test. The required post-LOCA temperature dropped to 190°F after 5 days and remained constant for an additional 175 days. Thus, although the test temperature envelopes the required post-LOCA temperature, it lasts only 25 days and not 175 days. It is a common practice to argue that the higher test temperature (212°F) can be viewed as an accelerated version of the actual post-LOCA temperature (190°F). After using Arrhenius methods to determine equivalent degradation for 25 days at 212°F and 175 days at 190°F, if it turns out the equivalent degradation for 25 days at 212°F is greater than 175 days at 190°F, it can be argued that the test is conservative with respect to the actual post-LOCA conditions.

Another example (provided by PNPS in response to an NRC Request for Additional Information) uses a device at PNPS that is required to be operable for a period of 33 days (30 days plus a 10- percent margin) in a temperature environment of 150°F maximum. Post-LOCA testing was conducted for a period of 20 days at 200°F. The Arrhenius equation is used to determine the equivalent time at the required temperature. Since the available time-temperature curve from the vendor is based on testing, the equivalency and margin utilized in qualification are determined utilizing Arrhenius techniques. The use of this method provides a means to quantitatively evaluate variable accident conditions to determine equipment thermal degradation. A Degradation Equivalency Analysis uses the Arrhenius Methodology to show that the degradation of the equipment experienced due to test conditions is equal to or greater than the degradation the equipment would experience from PNPS conditions.

The use of Arrhenius methodology to support qualification of equipment for LOCA and/or longer term post-LOCA environments has not been endorsed by NRC Regulatory Guide, has not been generally accepted, ***by itself****, to demonstrate qualification of equipment in post-LOCA environments, and has not been validated by either operating experience or research test results. Therefore, the use of Arrhenius methodology,* ***by itself*** *- without supporting justification or technical basis, is not considered an acceptable approach for supporting qualification of electric equipment for LOCA environments. Provide additional justification supporting the conclusion (i.e., engineering judgment) that equipment that has not been tested for the full time required by actual post-LOCA accident conditions remains qualified for the new higher post-LOCA environments, and/or provide supporting justification that Arrhenius methodology supports qualification of equipment for longer term post-LOCA environments.*

Answer:

BECo utilizes the Arrhenius Equation (consistent with industry practice) to demonstrate that post-accident operating time is acceptable using test data of a shorter duration than the PNPS specific accident profiles, but having higher temperatures than the required accident conditions. Boston Edison and our material specialist consultant are convinced that using the Arrhenius Methodology when extrapolating operating times, is a valid approach due to the temperature rating of materials generally used. For example, in the case of crosslinked polyethylene, EPR, EPDM, silicone rubber, Neoprene, Viton and others, these are processed by thermochemical crosslinking at 350°F or more, for at least 15 minutes, beyond which an extensive cooling period would have been experienced. Many of these materials are used commercially for extended periods in excess of 300°F. Accordingly, the materials can be used at high temperatures without undergoing chemical changes and therefore the Arrhenius Methodology is acceptable to use after the equipment has been subjected to LOCA type temperatures.

Question 7:

> *Based on information presented it appears that acceptability for qualification was originally based on a 10% weight loss of the penetration's epoxy sealant. Given this 10% weight loss as acceptance criteria, it is not clear how the results from linear slope comparison analysis can indicate a comparison ratio change from 0.55 to 2.00. It is not clear how it can be concluded (as implied by information presented in EQ qualification package) that both the original test (having a profile of 0.5 hours at 352°F plus 23.5 hours at 309°F plus 3 hours at 135°F) and the additional test (having a profile of 6 hours at 340°F and 10 days at 281°F) on the same material can produce a weight loss of 10%. Provide clarification.*

Answer:

The 10 percent weight loss acceptance criteria was developed by General Electric based on the design requirements for electrical penetrations. Available General Electric documents, concerning the penetration epoxy, indicate that a 15 percent weight loss would be acceptable. The test profiles listed were performed to prove the penetrations would survive specific accident scenarios. The longer, more severe test profile provides a higher ratio (2 to 1) when compared to the PNPS accident profile than the ratio (0.55) for the shorter, less severe test profile. The different accident test profiles removed different amounts of life from the penetrations. The tests were not designed to bring the epoxy to it's end of life condition (10% weight loss).

Question 8:

> *General Electric Proprietary Document NEDC-32123P, Report PIR-CPD9204F vice Life Estimate for the Epoxy Sealant in the Penetration Assemblies at the Brow..s Ferry Nuclear Plant Unit 3, dated August 20, 1992, indicates that the activation energy for the penetration's epoxy was revised from a value of 1.13 eV to 1.16 eV based the theory of life testing and use of thermogravimetric analysis (TGA). TGA does not provide a valid method for establishing the activation energy for material like the epoxy used in the penetration. The use of TGA is, thus, not considered acceptable. Describe how and to what extent TGA has been utilized for the qualification of electric penetrations and other equipment installed at Pilgrim.*

Answer:

An isothermal TGA test was used to justify the peak epoxy seal temperature expected on two PNPS low voltage power penetrations during an accident. The epoxy seal temperature on these penetrations could exceed the maximum temperature recorded during penetration qualification testing due to conductor heat up associated with the circuit load current. The isothermal TGA test (from G.E. report NEDC-32123P), referenced in the penetration evaluation report, showed that the penetration epoxy could withstand a higher temperature than required for the PNPS profile for 2.3 hours, before reaching the General Electric 10 % weight loss acceptance criteria. BECo concluded the isothermal TGA test data is acceptable justification for the maximum peak temperature based on the following: the limited time (10-15 minutes) the PNPS peak temperature may exceed the test temperature (<u>maximum</u> of 27°F); and the difference between the PNPS DBA pressure and the penetration qualification test pressure (PNPS required pressure approximately 1/3 the test pressure) and the conservatism in the 10 % weight loss criteria (G.E. states that a 15 % weight loss would be acceptable).

Note that BECo no longer takes credit for the above testing to establish the adequacy of the penetration epoxy for the peak conductor temperature expected at PNPS. Tests of a later version of General Electric penetrations utilizing the same XR5126 epoxy had the conductors energized at rated current during the LOCA test. This test enveloped the PNPS maximum conductor temperature requirements. TGA testing has not been used to justify the peak temperature for any other material or component.

BECo also used an activation energy obtained from the General Electric report NEDC-32123P in our life expectancy evaluation of the penetration seal epoxy. The General Electric report listed two activation energies (1.13 eV and 1.16 eV) obtained via two separate TGA tests conducted using different techniques. BECo used the more conservative (1.13 eV) activation energy for our evaluation. Using the 1.16 activation energy would increase the expected life of the epoxy from 62.8 years to 77.9 years at 150°F. As noted in response to question #5 above, Wyle Laboratories had reviewed the aging data for all epoxy resins in their material database in 1985 and had selected what was considered to be the most conservative material characteristics for evaluating the PNPS penetration epoxy seals. The new activation energy / test data from General Electric indicates the epoxy will have a shorter life expectancy than calculated in 1985. In fact, the calculated life at 150°F using the General Electric data is significantly less than all but one epoxy resin listed in the latest Wyle material database. (Note: The data in the Wyle database have varying acceptance criteria.) With the one exception, the next shortest life expectancy is 313 years at 150°F.

Generally, BECo does not evaluate the basis for the activation energies provided by equipment vendors. The vendor, as the designer of a component, understands the critical parameters of the materials used in their equipment and they must select the characteristics on which the activation energy is determined. BECo has used TGA testing to identify the insulation for a limited number of cables, the manufacturer of which was unknown. The activation energies were used to determine the basis for accelerated aging during qualification testing.

Question 9:

> *Wyle Report No. 47066-PEN-1.1, Qualification Verification Report on General Electric Electrical Penetrations No. 238X600NLG1 for use in Pilgrim 1 Nuclear Power Station, Revision F, dated March 20, 1996, indicates that a test profile of 340°F for 6 hours and 281°F for 10 days (which is described in General Electric Proprietary Test Report, Qualification Test for F01 electrical Penetration Assemblies, dated November 9, 1971) was used to show a test profile to plant requirement ratio of 2 to 1 for both the cast epoxy and the vulkene cable. Given that the test report dated November 9, 1971 only describes a qualification test of the penetration's epoxy, it is not clear what test was used for the vulkene cable to demonstrate it's qualification for the test profile of 340°F for 6 hours and 281°F for 10 days. Provide clarification.*

Answer:

Reference to this test report for qualification of the penetration vulkene wire for the PNPS accident was in error. The SI 57275 vulkene used in the GE penetrations had been evaluated for the accident scenario in Wyle Report 47066-CAB-1.1, Rev. C, dated March 25, 1996, "Qualification Verification on General Electric SI 57275 and SI 57279 For Use In Pilgrim 1 Nuclear Power Station". This report compared the PNPS accident profile against a LOCA test profile performed on vulkene insulated wire that had been previously aged for temperature and radiation. A 2.28 ratio between test and required temperature profiles indicates significant margin for this material. Note that the radiation aging for this test was less than required for PNPS. Previous testing (Wyle Laboratories Report 47839-02 dated November 29, 1985) was used to address the higher radiation levels.

The PNPS DBA profile used to evaluate the vulkene wire in Wyle report 47066-CAB-1.1 did not include conductor heat up due to electrical losses. All safety related circuits are low energy instrumentation and control circuits or MOV circuits that are energized for a short time (approximately 1 minute). These circuits will not increase conductor temperature significantly above the ambient temperature for any significant period. A 6°F margin between the maximum peak test temperature (340 °F) and the maximum required peak temperature (334 °F) should account for conductor heat up in these circuits. Note that the referenced test profile used in the evaluation did not include thermal heat up due to electrical loading even though #14 AWG conductors were energized at 10 amps for the first 10 hours of the LOCA test and that #8 AWG conductors were energized at 25 amps for 2 minutes (for MOV operation) a number of times during the LOCA test. The electrical load on the # 14 AWG during the LOCA test would have resulted in higher peak temperatures than those required for PNPS.

The Wyle Report No. 47066-PEN-1.1(Rev.G) has been revised to address the Vulkene wire. The General Electric Proprietary Test Report, "Low Voltage Power and Control Nuclear Containment Loss of Coolant Accident Qualification Test 100 Series Electrical Penetration F02 Program"(dated September 13, 1973), has been utilized to address the peak and post-LOCA temperature environment.

Finally, General Electric has confirmed that the General Electric F02 penetrations tested in 1973 (Low Voltage Power and Control Nuclear Containment Loss of Coolant Accident Qualification Test 100 Series Electrical Penetrations F02 Program) used the same epoxy and vulkene wire used in the PNPS penetrations. The F02 penetrations were tested with the penetration conductors energized at their maximum derated value for 30 to 60 minutes during the qualification test conducted at a maximum ambient temperature of 340°F. This test verified that the penetration epoxy / vulkene wire will not breakdown at the peak temperature expected at PNPS.

Question 10:

> *Provide the results of a linear slopes comparison analysis which utilizes Arrhenius methodology (similar to that shown in attachment 7 of General Electric Proprietary Document NEDC-32123P, Report PIR-CPD92045 Service Life Estimate for the Epoxy Sealant in the Penetration Assemblies at the Browns Ferry Nuclear Plant Unit 3, dated August 20, 1992) which compares the equivalent hours obtained for the test profile of 340°F for 6 hours and 281°F for 10 days to equivalent hours at the current plant accident requirements profile plus the equivalent hours for 40 years at 150°F.*

Answer:

This test profile was intended to prove the penetrations could survive the accident, not that they could survive the accident after 40 years at normal temperatures. Please see response to question #5 above.

Question 11:

> *Wyle Report No. 47066-PEN-1.1, Qualification Verification Report on General Electric Electrical Penetrations No. 238X600NLG1 for use in Pilgrim 1 Nuclear Power Station, Revision F, dated March 20, 1996 indicates that exposure of the penetration epoxy to radiation will cause weight loss (i.e., aging). From information presented in the EQ documentation package, it is not clear how aging due to radiation effects has been addressed and combined with aging due to thermal effects to demonstrate qualification of the penetration. Provide clarification.*

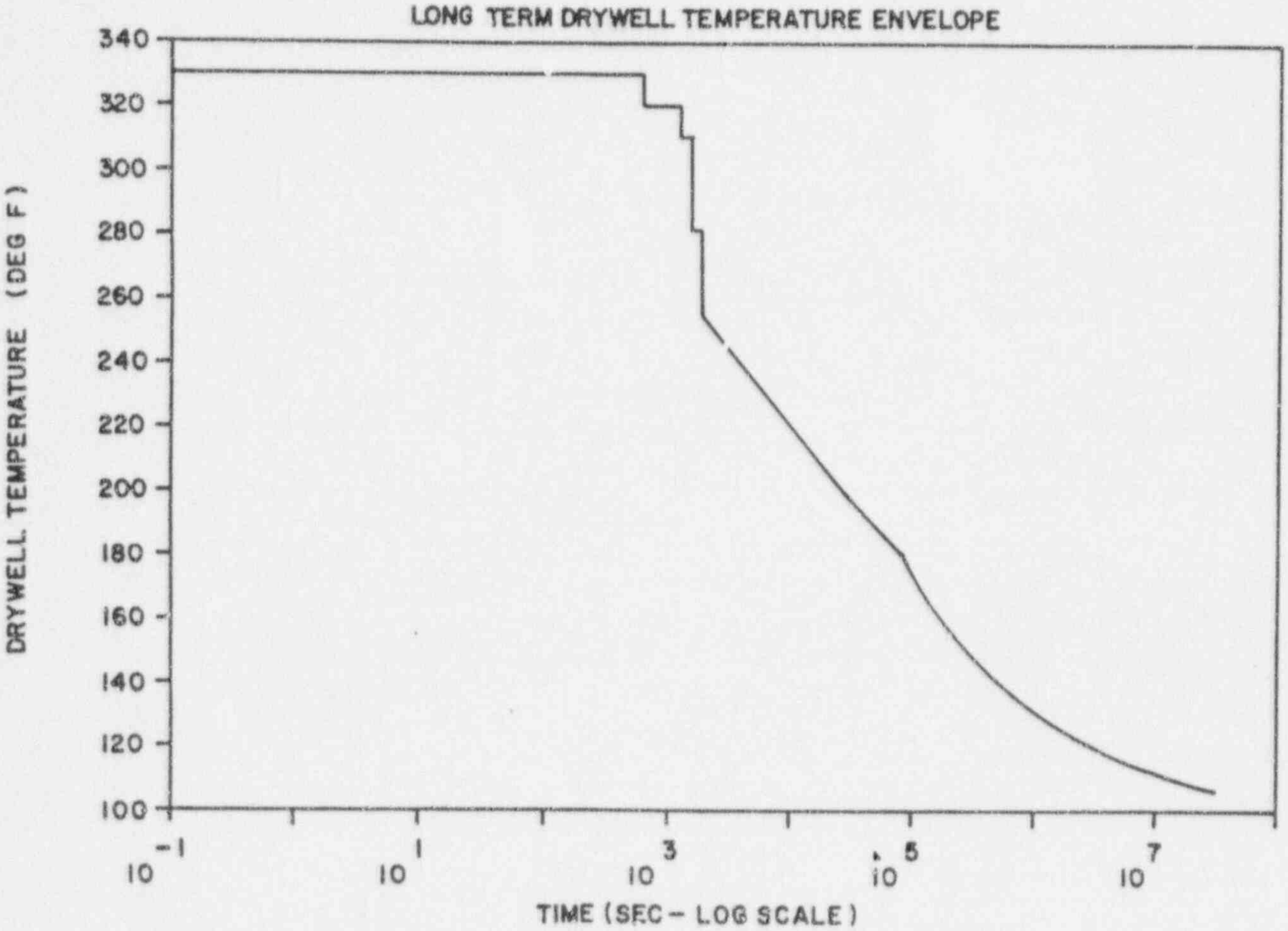
Answer:

The impact of radiation aging on the penetration epoxy was addressed in Wyle Report 47066-PEN-1.1 Rev. F. Some loss of life (< 25%) due to radiation was thought to be acceptable based on the relative insensitivity of the epoxy to the drywell temperature (424 years at 150°F). Once it was identified the activation energy used to calculate expected life of the epoxy in Rev.

F of the report was not correct and the expected thermal life dropped from 424 years to approximately 62 years, the affects of radiation aging were re-evaluated. Based on the radiation level expected at the penetration's primary containment side seal and General Electric's data for loss of weight at different radiation values, life was removed from the epoxy based on the % of weight lost relative to the 10 % weight loss allowed in the General Electric design. This loss of life due to radiation was combined with the thermal effects of the accident to determine the expected life of the penetration epoxy seals in an engineering evaluation dated October 1, 1996.

Since that time, Revision G of Wyle report 47066-PEN-1.1 was issued. This revision of the penetration qualification report provides a more detailed evaluation of the impact of radiation on the penetration epoxy. Specifically the report takes credit for a sacrificial layer of epoxy that reduces the impact of Beta to a negligible level in the area of the penetration seals. The remaining radiation, 2.85E7 Rads gamma, is below the damage threshold level of 1E8 Rads established via General Electric testing. Based on this evaluation, it has been determined that it is not necessary to reduce the expected life of the penetration epoxy due to the affects of radiation.

STEAM LINE BREAK



Attachment 3

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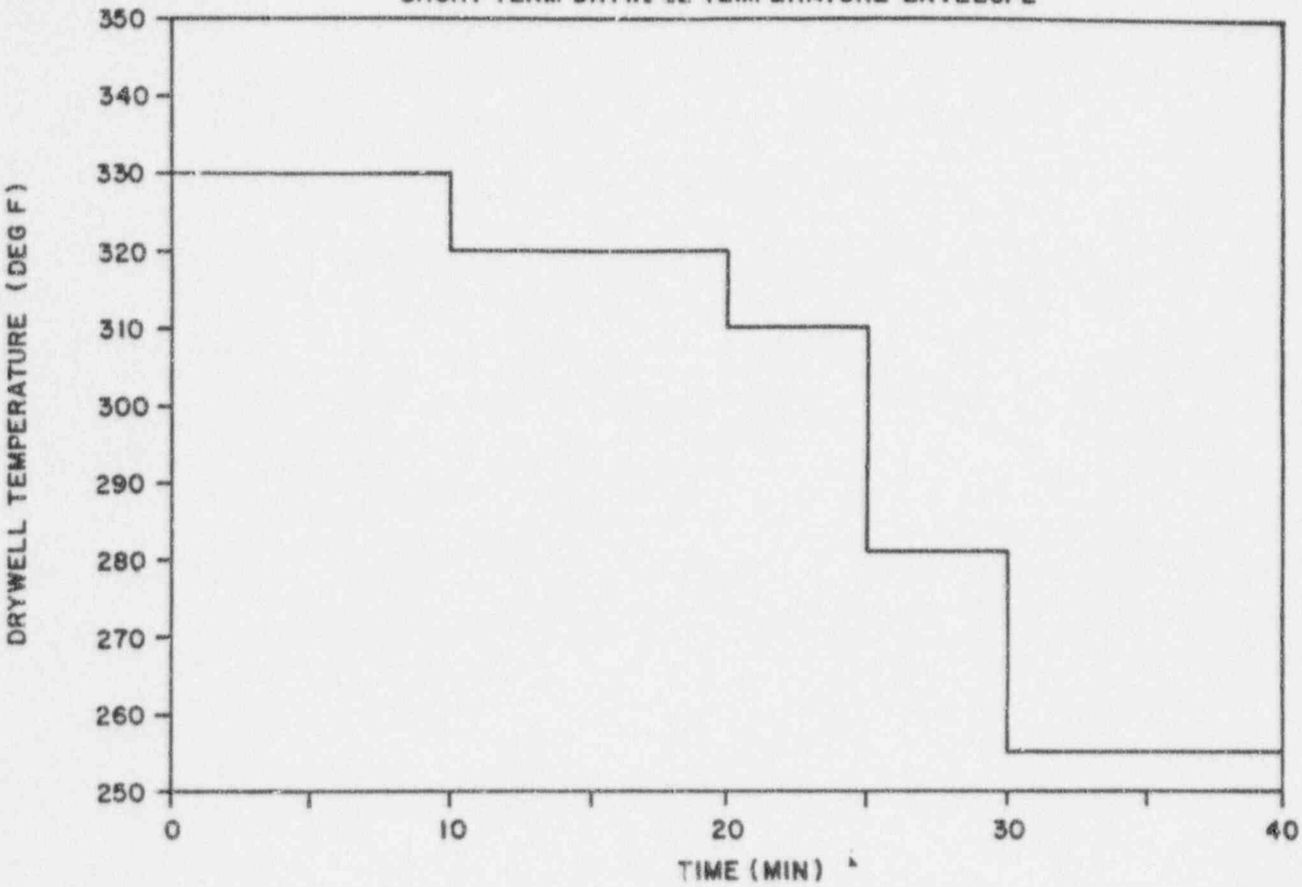
NSIDE CONTAINMENT

SHORT TERM DRYWELL TEMPERATURE ENVELOPE



NOTES:

1. INDIVIDUAL MSLB TEMPERATURE PROFILES FOR VARIOUS BREAK SIZES CAN BE FOUND IN SUDDS/RF# 87-917.
2. MSLB PRESSURE PROFILE IS BOUNDED BY THE DBA LOCA PRESSURE PROFILE. SEE FIGURE C.4.1-17 & SUDDS/RF# 87-917.
3. DRYWELL TEMPERATURE ENVELOPES ARE BASED ON A 30 MINUTE OPERATOR TIME DELAY IN THE INITIATION OF DRYWELL SPRAYS.

SPEC E-536, REV 4

FIGURE C.4.1-18

PAGE C-22

9705200047-01

Attachment 4

Response to NRC Request for Additional Information (RAI) dated April 17, 1997 (Enclosure questions 1 through 3)

RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION (RAI) DATED APRIL 17, 1997 (ENCLOSURE QUESTIONS 1 THROUGH 3)

In Enclosure 4 to your letter dated January 20, 1997, you provided Safety Evaluation (SE) No. 2983 which included the results of your analysis of a proposed temperature increase of the ultimate heat sink (UHS) from 65 to 75 degrees Fahrenheit (°F). Portions of that evaluation describe the effects of the temperature increase on equipment directly cooled by the reactor building closed cooling water (RBCCW) system. In order to complete our review and make an acceptability determination regarding this issue, we need the following additional information.

Question 1:

> *On Page [illegible] of SE No. 2983, you state that the function of the residual heat removal (RHR) pump seal coolers is to prevent flashing at the RHR pump seal faces and explain why this cooling is not necessary for post-accident operation of the pumps. You further described that the seal coolers are only necessary when the RHR pumps operate in the shutdown cooling (SDC) mode. However, you did not provide information to verify that RHR pumps will not be damaged by seal flashing when operating in the SDC mode with the UHS at the increased temperature of 75°F (corresponding to a peak RBCCW temperature of 98°F). Please provide additional information to describe why the increase in RBCCW temperature is acceptable when the RHR pumps are operating in the SDC mode. This additional information should also include verification that safe cold shutdown following a fire can still be achieved within 72 hours in accordance with Appendix R to 10 CFR Part 50.*

Answer:

The RHR pump seal coolers are a necessary feature to allow the RHR pumps to operate in the shutdown cooling (SDC) mode. Under shutdown cooling conditions, the RHR pump seal chamber must be maintained below 212°F. The source for the mechanical seal flush water is the RHR pump discharge. The single stage RHR pump has a hydraulically balanced impeller with pressure equalizing holes from the impeller backside to the suction eye which creates a substantial differential pressure between the pump discharge and seal chamber. The seal cooler is a small heat exchanger comprised of a single tubing coil for the hot RHR water and a shell cooled by the RBCCW system.

The seal cooling requirements were reviewed as part of the 75°F heat sink analysis for the shutdown cooling mode of operation. The limiting conditions for seal cooling were determined for RHR shutdown cooling operating at a 300°F pump temperature with the RBCCW system heated up to its maximum steady state temperature of 130°F based on a 75°F UHS temperature. The peak RBCCW temperature of 98°F referenced in the above question refers to the peak RBCCW cooling water temperature during operation following a DBA-LOCA [Ref. 1 to this attachment]. For the limiting SDC case, the RHR pump discharge water is supplied at 300°F and 2.5 to 3.5 gpm with RBCCW cooling water supplied at 130°F and 20 gpm. Under

these conditions, the seal cooler outlet supplying the RHR seal flush is maintained below 202°F. These conditions and the assumptions used are bounding; actual shutdown cooling conditions are typically more favorable. It was concluded that the seal cooling system will operate satisfactorily over the full range of shutdown cooling operation with a 75°F UHS temperature. The analysis performed is documented in a BECo calculation [Ref. 5 to this attachment].

The accident scenario for a fire event per Appendix R to 10 CFR Part 50 was included in the 75°F Containment Heat Removal Analysis [Ref. 2 to this attachment]. The fire scenario results in immediate equipment losses such that only two SRVs and one core spray pump are available for pressure relief and core cooling, with one RHR loop available for heat removal. This configuration allows the reactor to be depressurized with inventory control via the core spray pump while the one RHR loop performs suppression pool cooling. The SRVs continue to be used to maintain low reactor pressure for a finite time period. For containment analysis, the bounding assumptions are that this configuration is maintained for approximately 50 hours to obtain the highest drywell and suppression pool temperatures. The peak suppression pool temperature of 174.4°F occurs at 8.6 hours into the event when cooling is initiated at 2 hours.

To achieve cold shutdown (<212°F) requires that RHR shutdown cooling be established at some point. This may be achieved by taking the operating RHR loop out of suppression pool cooling to begin SDC when the reactor is sufficiently depressurized. RHR shutdown cooling capability with a 75°F UHS temperature was evaluated in a 1995 GE Report [Ref. 3 to this attachment]. It was concluded that with a single RHR loop available for shutdown cooling, the reactor vessel fluid can be cooled down to below 212°F within 8 hours after reactor shutdown assuming an initial cooldown of 50°F/hr for 6 hours such that the RHR system is started at 260°F which is characteristic of a normal shutdown. Therefore, for the fire event, cold shutdown can be achieved well within 8 hours after shutdown cooling is initiated since the reactor will be sufficiently depressurized at that point and the decay heat will be lower than for a normal shutdown. With respect to the RHR seal cooler evaluation, the bounding conditions were evaluated for the limiting SDC conditions as described above.

Question 2:

> *On Page 30 of the SE you also discuss the effects of the increased RBCCW temperature on the operation of the core spray (CS) pumps. In that discussion, you state that "The calculated cooling water inlet and outlet temperatures are well within the acceptable range to ensure reliable operation of the core spray pump motors with a SSW injection temperature of 75°F." This general statement implies (but is not explicit) that the temperature of the cooling water RBCCW to the CS pump motor coolers remain within the design range of acceptable cooling water inlet temperatures for the CS pump motors. Verify that the peak RBCCW temperature (98°F) is within the design limits for CS pump motor cooling, or if it is not, provide the justification for your conclusion that pump operation is acceptable for the duration of design basis accidents.*

Answer:

The core spray pumps have 800 HP 3600 RPM General Electric vertical open dripproof motors. The single stage pump impellers are supported by a radial pump bearing with all axial loads supported by the motor. The motor upper bearing is a duplex set of 40-degree angular contact ball thrust bearings, and the lower is a single row radial ball bearing. The motor bearings are oil-bath lubricated. The upper thrust bearing oil sump includes an oil cooling coil connected to the RBCCW system. The nominal cooling water requirement is specified as 4 gpm with 165°F maximum for short period of time [Ref. 4 to this attachment]. The peak RBCCW supply temperature for the DBA-LOCA is 98°F. The cooling water supply was judged acceptable based on the motor specifications as well as engineering judgment for this application. For a thrust bearing of this type, the cooling requirement is met if the bearing oil temperature is maintained below 180°F. The design heat load is 15,000 Btu/Hr which results in a temperature rise of only 8°F for the 4 gpm cooling water. It was, therefore, judged that the RBCCW peak temperature poses no challenge to the core spray pump motors.

Question 3:

> *On Page 31 of your evaluation, you discuss building compartment cooling and provide the same type of general statements as we discussed in the above Item 2. For the motor control center (MCC) ventilation, you state that "the temperature in the enclosures will remain sufficiently low to ensure reliable operation." On the same page, for the equipment area cooling, you state that "the temperature results for building compartments served by equipment area cooling as well as those that do not [i.e., receive local cooling from an equipment area cooler] were evaluated against temperature limits for the local equipment and found acceptable to ensure reliable operation." In neither case did you state that the temperature remains within the equipment design limits. Verify that the area temperatures and the temperature in the MCC enclosures remain within the equipment design limits at the increased RBCCW temperature, or if they do not, provide justification for your determination that the equipment and/or MCCs will remain operable.*

Answer:

All safety-related equipment located within the MCC enclosures and the building compartments have been evaluated for the effects of the site maximum heat sink temperature of 75°F, and the temperatures of all equipment within the applicable locations have been determined to remain within the equipment design limits.

REFERENCES

1. BECo Calculation M-664 Rev. 0 "Containment Heat Removal".
2. GE Report GE-NE-T23-00732-01 "Containment Heat Removal Analysis", March 1996, SUDDS/RF # 96-05.

3. GE Report GE-NE-523-A044-0595 "Decay Heat Removal Capability", May 1995, SUDDS/RF # 95-127 Rev. 1.

4. BECo Dwg 2639-1-5 Rev. E2 "Outline Drawing Core Spray Pump Motors"

5. BECo Calculation M-737 Rev. 0 "RHR Shutdown Cooling Evaluation".

Attachment 5

User Defined Inputs for ANS 5.1-1979 Decay Heat - Reanalysis Using 2σ Uncertainty

User Defined Inputs for ANS 5.1-1979 Decay Heat - Reanalysis Using 2σ Uncertainty

PARAMETER	UNITS	VALUE FOR ANALYSIS	REFERENCE
Initial Core Thermal Power (102% of Rated Power)	MWt	2,038	(Note 1)
Decay Heat:			
Method of Calculation	N/A	ANSI/ANS 5.1-1979	1, (Note 2)
Fuel Enrichment	% U235	4.2	(Note 3)
Reactor Full Power Level	MWt	2,038	(Note 1)
Effective Full Power Days EFPDs	Days	1,825	
Fuel Total Exposure	MWD/ton	32,500	
Total Energy Released per Fission Q	MeV/fission	207.16	
Uncertainty for Energy Released per Fission ΔQ for 2σ	% Q	0.25	
Isotopic Fission Fraction for U235 @ Shutdown	% Total	50.0	(Note 3)
Isotopic Fission Fraction for Pu239 @ Shutdown	% Total	41.8	(Note 3)
Isotopic Fission Fraction for U238 @ Shutdown	% Total	8.2	(Note 3)
Actinide Production Multiplier R-factor	N/A	0.6	(Note 3)
Neutron Capture Multiplier G-factor (t up to 10,000 sec)	N/A	Equation 11	1
Neutron Capture Multiplier G-factor (t > 10,000 sec)	N/A	G_{max} Table	1
Si Coefficient for G-factor Multiplier ψ	N/A	0.856	(Note 4)
Uncertainty for Decay Heat Power $\Delta f_i(t)$	Std. Deviations	2σ	1
Fission Heat from Delayed Neutrons $\%P_O(t)$	$\%P_O$	Table 7	3

User Defined Inputs for ANS 5.1-1979 Decay Heat - Reanalysis Using 2σ Uncertainty cont'd

NOTES:

1. 102% value, as required by Regulatory Guide 1.49.
2. Decay heat is calculated using the methods given in ANSI/ANS 5.1-1979, and the values listed in this table are the required user provided inputs for the calculation.
3. Values for the isotopic fission fractions and the actinide R-factor are a function of fuel enrichment and fuel exposure. Total decay heat is nearly independent of fuel enrichment [Ref. 2]. Based on this, the decay heat calculations are conservatively performed for fuel with an average enrichment of 4.2% and these results are valid for all the fuel enrichments actually used. Since the isotopic fractions and R-factor vary with enrichment, the values of these parameters given for 4.2% enriched fuel are representative values only. In addition, since these parameters vary with fuel exposure, the values given correspond to core average values and individual fuel bundles will vary significantly from the average since the core contains different batches of fuel spanning a wide range of exposures at any one time.
   For the core average total exposure assumed (32,500 MWD/ton), the isotopic fission fractions for fuel with 4.2% enrichment are distributed as given in this input table.
4. The Si coefficient (ψ) is a function of the total exposure and is used in the calculation of the G-factors for shutdown times $t < 10^4$ seconds. The ψ coefficient increases with fuel MWD/ton exposure and is a function of enrichment [Ref. 3]. A value of $\psi = 0.856$ was used for the calculated G-factors for shutdown times up to 10^4 seconds. For the $G_{max}(t)$ values tabulated in ANSI/ANS 5.1 and used for shutdown times $t > 10^4$ seconds, the ψ coefficient is not given as a separate parameter.

REFERENCES:

1. ANSI/ANS 5.1-1979 "Decay Heat Power in Light Water Reactors", August 1979.
2. GE NEDO-23729 "Nuclear Basis for ECCS (Appendix K) Calculations", November 1977.
3. GE NEDC-23785P "The GESTR-LOCA and SAFER Models for the Evaluation of Loss-of-Coolant Accident", October 1984.

Attachment 6

Pilgrim Calculation No. PS-79, Revision 4

ATTACHMENT "A"

CALCULATION COMMENT SHEET No. PS ~~XX-YY~~ 79-9

This form is to be utilized when capturing changes to the subject calculation which should be included in the next revision but are not critical to be the subject of an immediate revision.

Calculation Title: Emergency Diesel Generator Loading

Calculation Number: PS-79

Current Revision: 4

Reason for Future Revision: Because of the higher (75°F) bay water temperature, it is necessary to start a second SSW pump and a second RBCCW pump earlier than previously assumed during a LOCA; i.e before one of the ECCS pumps is shutdown (but after the automatic sequencing of LOAD BLOCK #1 & #2 MOV.

Justification for Deferral in Revision:

The attached shows that adding the extra pumps as indicated above does not result in the diesel generators exceeding their 2000 yr rating for continuous loading.

References/Attachments:

Calculation Pages Affected:

Various

Cognizant Engineer: John Coughlin Date: 4/22/97

Independent Reviewer: Jeff Mat[illegible] Date: 5/5/97

Division Manager: [illegible] Date: 5/8/97

Based on a higher (75 ^{0} F) bay temperature, it has been determined, as documented in Calc. S&SA 91 Rev. E0 (Containment & Decay Heat Removal Analysis Inputs), that in order to provide the necessary cooling during a LOCA , two Salt Service Water pumps and two RBCCW pumps are required to be operating prior to shut-down of one of the ECCS pump. The existing Diesel Generator loading calculation assumes only one pump of each system operating prior to shut down of an ECCS pump.

The following evaluation shows that at least one diesel generator will be available assuming two SSW and two RBCCW pumps are operating during the 10 minute to 2 hour time interval after a LOCA, assuming the same worst case failures used in PS-79 Rev. 4. That is, at least one diesel generator has a steady state load of less than the 2000 hour, long term, continuous rating of 2750 KW for the diesel generator units.

The following evaluation is based on RBCCW and SSW pump loading when two pumps per train are operating. The RBCCW and SSW pump flow rates listed below are from Calculations M664 Rev 0 and M630 Rev 1, respectively:

RBCCW	3772.9 gpm	Assume 1900 gpm per pump
SSW	5553.49 gpm	Assume 2800 gpm per pump

Based on these pump flow rates, the pump motor loading will be revised as follows:

RBCCW Pump BHP	55 HP (pump curve M14BC15-1)
Motor KW	= (BHP * 0.746)/motor Efficiency = (55 * 0.746) / .9 (Eff. M14B32-1) = 45.6 KW
SSW Pump BHP	93 HP (pump curve M8-35)
Motor KW	= (BHP * 0.746)/motor Efficiency = (93 * 0.746) / .92 (Eff. M8-7-1) = 75.4 KW

The change in diesel generator loading due to running the two additional pumps will be:

RBCCW	minus 54 KW for single pump operating add 2 * 45.6 KW for two operating pumps add 0.26 KW for worst case cable loss for added pump Total added load = 37.5 KW
SSW	minus 83 KW for single pump operation add 2 * 75.4 KW for two operating pumps add 1.9 KW for worst case cable loss for added pump Total added load = 69.7 KW

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MAXIMUM STEADY STATE LOAD (10 Min. to 2 Hrs)

CASE NO.	EDG 'A' R #4 Load	EDG 'A' Add. Load	EDG 'A' Tot. Load	EDG 'B' R #4 Load	EDG 'B' Add. Load	EDG 'B' Tot. Load
BASE	2560	107.2	2667.2	2561	107.2	2668.2
A	3185	37.5	3222.5	2561	107.2	2668.2
B	2636	107.2	2743.2	2384	107.2	2491.2
C	2560	107.2	2667.2	0	-	0
D	[illegible]	107.2	2667.2	3052	37.5	3089.5
E	[illegible]	-	0	2561	107.2	2668.2
F	2700	37.5	2737.5	2384	107.2	2491.2

The initial diesel loading in the table above is from Table 1 of PS-79 Rev #4. 37.5 KW for the extra RBCCW pump has been added for all cases. 69.7 KW has been added for only those cases where the assumed failure did not result in more than one SSW pump operating. Operating the largest individual MOV (MO1001-28 A / 28 B, 77 KW) during this time, will not cause the total load on a previously available diesel to exceed the diesel's specified 2860 KW, 2 hours / 24 hour rating.

Note that Calc. S&SA 91 assumes that the extra SSW and RBCCW pumps are started after the maximum coincident MOV load, identified as the short time load in Table 1 of PS-79 Rev 4, has finished operating. Therefore, the maximum coincident load identified as the 0 to 10 min. load on Table 1, remains unchanged. Calc. S&SA 91 also assumes that a RHR pump will be shutdown after 2 hours. With one ECCS pump off, the long term load, identified as the > 10 min. load on Table 1 (which will be changed to >2 hours), also remains unchanged. Based on the above, the continuous loading shown in the above table is only applicable between 10 minutes and two hours.

In order to insure that the diesel generators do not exceed the 2860 KW 2 hour rating, it is necessary that station procedures limit the start of the second SSW / RBCCW pump until RHR and Core Spray injection has been initiated or one of the ECCS pumps on the diesel generator has been shutdown..

JJc

Note that starting a RHR pump, which has a heavier starting load than the CS pump, after all other loads are operating at their maximum assigned load will not result in the total diesel load exceeding the 3000 KW 2 hour rating. The RHR pump motor will draw 840 KW during start (4160 volts, 555 amps, .21 LR pf). This is 201 KW greater than the 639 KW for a RHR pump operating at rated load. Adding the 201 KW to the worst case steady state load of 2744.2 KW calculated above, indicates a maximum co-incident load of 2945.2 KW. The voltage regulator should be able to recover the bus voltage since the response of the regulator is more responsive when the diesel generator has a base load.