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NINE MILE POINT
NUCLEAR STATION

June 1, 2010

U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001

ATTENTION: Document Control Desk

SUBJECT: Nine Mile Point Nuclear Station
Unit No. 2; Docket No. 50-410

License Amendment Request Pursuant to 10 CFR 50.90: Extension of the Completion Time for an Inoperable Diesel Generator – Response to NRC Acceptance Review Comments (TAC No. ME3736)

REFERENCES:
(a) Letter from S. Belcher (NMPNS) to Document Control Desk (NRC), dated March 30, 2010, License Amendment Request Pursuant to 10 CFR 50.90: Extension of the Completion Time for an Inoperable Diesel Generator – Technical Specification 3.8.1, AC Sources – Operating

(b) Letter from R. V. Guzman (NRC) to S. L. Belcher (NMPNS), dated May 11, 2010, Nine Mile Point Nuclear Station, Unit No. 2 – Acceptance Review of Requested Licensing Action Re: Extension of Completion Time for Inoperable Diesel Generator (TAC No. ME3736)

Nine Mile Point Nuclear Station, LLC (NMPNS) hereby transmits supplemental information in support of a previously submitted request for amendment to Nine Mile Point Unit 2 Renewed Operating License NPF-69. The request, dated March 30, 2010 (Reference a), proposed to modify Technical Specification Section 3.8.1, "AC Sources – Operating," to extend the Completion Time for an inoperable Division 1 or Division 2 diesel generator from 72 hours to 14 days. By letter dated May 11, 2010 (Reference b), the NRC forwarded comments required to be addressed prior to the staff's completion of the acceptance review for the amendment request. The supplemental information, provided in Attachment 1 to this letter

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and supported by the other attachments (Attachments 2 and 3) referenced therein, responds to each of the acceptance review comments documented in Reference (b).

The supplemental information contained in this submittal does not affect the No Significant Hazards Determination analysis provided by NMPNS in Reference (a). Pursuant to 10 CFR 50.91(b)(1), NMPNS has provided a copy of this supplemental information to the appropriate state representative. This letter contains no new regulatory commitments.

Should you have any questions regarding the information in this submittal, please contact T. F. Syrell, Licensing Director, at (315) 349-5219.

Very truly yours,

STATE OF NEW YORK :
: **TO WIT:**
COUNTY OF OSWEGO :

I, Thomas A. Lynch, being duly sworn, state that I am Plant General Manager, and that I am duly authorized to execute and file this supplemental information on behalf of Nine Mile Point Nuclear Station, LLC. To the best of my knowledge and belief, the statements contained in this document are true and correct. To the extent that these statements are not based on my personal knowledge, they are based upon information provided by other Nine Mile Point employees and/or consultants. Such information has been reviewed in accordance with company practice and I believe it to be reliable.

Subscribed and sworn before me, a Notary Public in and for the State of New York and County of Oswego, this 1st day of June, 2010.

WITNESS my Hand and Notarial Seal:

Amy A. Green
Notary Public

AMY A. GREEN
Notary Public State of New York
Registration No. 01GR5038047
Qualified in Oswego County
Commission Expires January 17, 2011

My Commission Expires:

1/17/11
Date

TAL/DEV

Attachments:

1. Nine Mile Point Unit 2 – Response to NRC Acceptance Review Comments Regarding the Proposed Extension of the Completion Time for an Inoperable Diesel Generator

2. Comparison of the NMP2 Fire PRA Model to the Technical Elements of Regulatory Guide 1.200, Revision 2, Section 1.2.4

3. Comparison of the NMP2 Seismic PRA Model to the Technical Elements of Regulatory Guide 1.200, Revision 2, Section 1.2.6

cc: S. J. Collins, NRC
R. V. Guzman, NRC
Resident Inspector, NRC
A. L. Peterson, NYSERDA

ATTACHMENT 1

NINE MILE POINT UNIT 2

RESPONSE TO NRC ACCEPTANCE REVIEW COMMENTS

REGARDING THE PROPOSED EXTENSION OF THE COMPLETION

TIME FOR AN INOPERABLE DIESEL GENERATOR

ATTACHMENT 1

NINE MILE POINT UNIT 2
RESPONSE TO NRC ACCEPTANCE REVIEW COMMENTS REGARDING THE PROPOSED EXTENSION OF THE COMPLETION TIME FOR AN INOPERABLE DIESEL GENERATOR

By letter dated March 30, 2010, Nine Mile Point Nuclear Station, LLC (NMPNS) requested an amendment to Nine Mile Point Unit 2 (NMP2) Renewed Facility Operating License NPF-69. The proposed amendment would modify Technical Specification (TS) Section 3.8.1, "AC Sources – Operating," to extend the Completion Time for an inoperable Division 1 or Division 2 diesel generator (DG) from 72 hours to 14 days. This attachment provides supplemental information in response to the acceptance review comments documented in the NRC's letter dated May 11, 2010. Each individual NRC comment is repeated (in italics), followed by the NMPNS response.

Probabilistic Risk Assessment (PRA) Licensing Review

Comment 1

The submittal identifies that fire and seismic risk are included in the PRA model. A single paragraph referring to the individual plant examination for external events (IPEEE) submittal and to the NRC IPEEE evaluation is provided, along with a table of the NRC review comments and their disposition from the IPEEE. The purpose of the IPEEE and the NRC Research Office staff evaluation was to identify significant plant vulnerabilities, not to establish that the analyses were state-of-the art risk analyses to support licensing actions. This level of quality is not acceptable to support a risk-informed Technical Specification (TS) change. The licensee will need to submit PRA quality information on its fire and seismic risk models consistent with Regulatory Guide (RG) 1.200, Revision 2, Section 1.2.4 (fires) and 1.2.6 (seismic) to demonstrate that these quantitative models are adequate for this application. The licensee should also submit confirmation that the existing fire and seismic models, stated to be based on the IPEEE, still adequately reflect the current plant configuration with regards to mitigation of these events.

Response

As noted in Section 3.2.1 of the license amendment request (submittal), the NMP2 IPEEE evaluation is used as the basis for the internal fire and seismic models which are incorporated directly into the at-power internal events PRA model. This allows fire and seismic initiating events to be quantified using the latest internal events fault trees and accident sequences, with the external event initiators failing the appropriate systems, functions, and crew response actions. The current internal fire and seismic PRA models are in accordance with the guidance in Sections 1.2.4 and 1.2.5, respectively, of RG 1.200, Revision 1. NMPNS has confirmed that these models continue to adequately reflect the current plant configuration with regard to mitigation of these events by reviewing modifications to the plant that have occurred since the IPEEE was performed.

It is recognized that the internal fire and seismic PRA models do not meet all of the supporting requirements of Capability Category II of ASME/ANS PRA Standard RA-Sa-2009. Nevertheless, it is judged that these hazard analyses provide reasonable evaluations of the quantitative contribution to the risk metrics associated with the proposed extension of the Completion Time (CT) for an inoperable Division 1 or Division 2 DG. This conclusion is based on an assessment that compares the internal fire and seismic PRAs to the technical elements outlined in RG 1.200, Revision 2. Further discussion regarding the internal fire and seismic PRA models is provided below.

Internal Fire PRA

The internal fire events analysis that is documented in the IPEEE is used as the basis for the NMP2 internal fire hazard quantification. In the IPEEE, internal fires were addressed by using a combination of the Fire Induced Vulnerability Evaluation (FIVE) methodology and fire PRA techniques described in NUREG/CR-4840. The NMP2 fire PRA study is a detailed analysis that uses quantification and model elements (e.g., system fault trees, event tree structures, random failure rates, common cause failures) consistent with those employed in the internal events portion of the NMP2 PRA.

The approach taken for the fire PRA was to perform a scenario-by-scenario analysis of unscreened compartments accounting for the relative location of ignition sources and targets, fire severity, damage thresholds, and fire suppression. The PRA was preceded by a fire compartment interaction analysis and a quantitative screening analysis, both performed in a manner consistent with the FIVE guidance.

Internal fire events are integrated with the internal events model and contribute approximately 30 percent to the baseline core damage frequency (CDF) and 19% to the baseline large early release frequency (LERF) for NMP2. However, because only a small fraction of the fire-induced core damage sequences lead to a loss of offsite power (when the DGs would be required), the results of the risk evaluation for the proposed amendment show that the contribution of fire event sequences to the delta risk estimates is relatively small.

NMPNS has performed an assessment that compares the current NMP2 internal fire PRA model to the technical elements outlined in Section 1.2.4 of RG 1.200, Revision 2. The results of this assessment are summarized in Attachment 2, which follows the format of Table 5 in RG 1.200, Revision 2. In those cases where the current internal fire PRA model is not entirely consistent with the technical elements of RG 1.200, Revision 2, assessments that include sensitivity studies have been performed to demonstrate that the model is still adequate for application to the proposed amendment.

Seismic PRA

The seismic analysis that is documented in the IPEEE is used as the basis for the NMP2 seismic hazard quantification. A seismic PRA analysis approach was taken to identify potential seismic vulnerabilities at NMP2. The NMP2 seismic PRA method uses an acceptable methodology as identified in NUREG-1407. This PRA technique includes consideration of the following elements:

- Seismic hazard analysis
- Seismic fragility assessment
- Seismic systems analysis
- Quantification of the seismically induced core damage frequency

The NMP2 seismic analysis also included the following elements:

- Human interactions and recovery actions under seismic conditions
- Relay chatter during a seismic event
- Containment performance during a seismic event

In the NMP2 response to Generic Letter 88-20, Supplement 4, NMPNS committed to the EPRI seismic margins analysis (SMA) method. Understanding the importance of the PRA in support of decision making and that the IPEEE should add to the completeness of the PRA, the review level earthquake (RLE) used for screening was 0.5g, rather than 0.3g, as recommended by NUREG-1407. The seismic capacity of NMP2 was expected to be high; utilizing a 0.5g RLE provides more knowledge relative to the seismic capability of the plant. Relays that could impact the success path due to chatter were identified and evaluated rather than attempting to identify only those most susceptible to failure.

Seismic hazard analysis was performed to estimate the annual frequency of exceeding different levels of seismic ground motion at the plant site. The seismic hazard analysis focused on the identification of the sources of earthquakes that may impact the Nine Mile Point site, evaluation and assessment of the frequencies of occurrence of earthquakes of different magnitudes, estimation of the intensity of earthquake-induced ground motion (e.g., peak ground acceleration) at the site, and finally, the integration of this information to estimate the frequency of exceedance for selected levels of ground motion. For the Nine Mile Point site, there are two published site-specific hazard studies that were used in the IPEEE: (1) EPRI NP-6395-D, "Probabilistic Seismic Hazard Evaluation at Nuclear Power Plant Sites in the Central and Eastern United States: Resolution of the Charleston Earthquake Issue," and (2) NUREG-1488, "Revised Livermore Seismic Hazard Estimates for 69 Nuclear Power Plant Sites East of the Rocky Mountains."

Seismic events contribute approximately 4% to the baseline CDF and 35% to the baseline LERF for NMP2. Note that accident scenarios involving postulated seismic-induced DG failure have no contribution to the delta risk estimates of this analysis. This fact is due to the high correlation of seismic induced failures of similar equipment in like locations, i.e., all DGs would be failed (this is a standard seismic PRA modeling approach). Therefore, for accident scenarios involving seismic induced DG failure, there is no difference in the CDF whether one of the DGs is out of service for maintenance or not.

NMPNS has performed an assessment that compares the current NMP2 seismic PRA model to the technical elements outlined in Section 1.2.6 of RG 1.200, Revision 2. The results of this assessment are summarized in Attachment 3, which follows the format of Table 7 in RG 1.200, Revision 2. In those cases where the current seismic PRA model is not entirely consistent with the technical elements of RG 1.200, Revision 2, sufficient discussion is provided to demonstrate that the model is still adequate for application to the proposed amendment.

Comment 2

Other plant hazards are not identified as included in the quantitative risk analyses, nor are qualitative dispositions provided to determine that the risk from these hazard groups is insignificant. This is inconsistent with RG 1.174 which requires all hazards to be addressed. The licensee will need to address these external hazards unless they are included in the quantitative results; if so, then the technical adequacy of these PRA models will then need to be addressed per RG 1.200 Section 1.2.

Response

The NMP2 IPEEE performed an examination of high winds and tornados, external floods, and transportation and nearby facility accidents (referred to as "other hazards") to assess their potential for impacting the NMP2 risk profile. Utilizing the progressive screening methodology described in NUREG-1407, the evaluation for each type of potential hazard included, as a minimum, a review of the plant relative to the hazard, a review of changes since the issuance of the plant's operating license, and a review of the plant against the 1975 Standard Review Plant (SRP). The IPEEE concluded that there was no significant quantitative risk contribution from these other hazards (i.e., they were screened), and none of the other hazards were required to be added to the PRA model. The underlying basis for this conclusion was NMP2 conformance with the SRP, which included consideration of hazard frequency and plant design.

Since the IPEEE was performed, the only significant change relating the other hazards has been the addition of a common hydrogen gas storage facility for Nine Mile Point Unit 1 (NMP1) and NMP2 to support implementation of reactor coolant system hydrogen water chemistry. The addition of the hydrogen storage facility was evaluated and found to have a negligible impact on CDF and was screened from further consideration in the NMP2 PRA.

The proposed amendment to extend the CT for an inoperable Division 1 or Division 2 DG does not alter the conclusion of the IPEEE that the other hazards are negligible contributors to plant risk; therefore, explicit treatment of these other hazards is not necessary.

Comment 3

The evaluation of the internal events PRA model using RG 1.200 and the applicable PRA standard does not identify the relevant capability category(ies) associated with this application, nor is the capability category(ies) of the PRA model identified in the submittal. This is inconsistent with RG 1.200 Section 4.2. The licensee will need to supplement their submittal to address the capability category(ies) of the standard applicable to this analysis.

Response

The NMP2 updated internal events PRA model used to perform the risk evaluation for the proposed license amendment meets American Society of Mechanical Engineers and American Nuclear Society (ASME/ANS) PRA Standard RA-Sa-2009, Capability Category II requirements.

Comment 4

There is no statement regarding any permanent plant changes implemented but not incorporated into the PRA model used to support this risk analysis. This is inconsistent with RG 1.200 Section 4.2. The licensee will need to supplement their submittal to address this issue.

Response

The internal events PRA model used to support the proposed license amendment reflects the as-designed, as-operated plant at the time that the risk evaluation was performed. All permanent plant changes either have been incorporated into the PRA or have been evaluated as not relevant to the PRA. In addition, a review of currently planned permanent plant changes has been performed. Two planned plant changes are already incorporated into the internal events PRA model, as discussed in Section 3.2.1 of the submittal (i.e., extended power uprate and the Division 3 DG backup cooling water supply). Other than those two changes, the review did not identify any other currently planned changes (such as design or operational practices) that would have a significant effect on the risk evaluation performed for the proposed license amendment. PRA model maintenance is further discussed in Section 3.2.2 of the submittal.

Please refer to the response to Comment 1 regarding the internal fire and seismic PRA models.

Comment 5

The submittal makes extensive commitments to Tier 2 equipment restrictions (Section 3.2.5) which are credited in the risk analyses. These restrictions are to be incorporated into plant procedures and the TS bases, but not into the TS action requirements. There is no sensitivity analyses provided to allow the NRC staff to determine which, if any, of these restrictions are critical to the acceptance of this change. The licensee will need to provide appropriate sensitivity analyses to permit NRC staff review of the acceptability of these restrictions and their control in procedures and TS bases, rather than in the TS actions.

Response

As described in Section 3.2.5 of the submittal, the following compensatory measures and configuration risk management controls have been credited in the PRA evaluation for the proposed amendment:

Case #	Tier 2 Equipment Restrictions	Sensitivity Case
1	The other two DGs are operable and no planned maintenance or testing activities are scheduled on those two DGs.	N/A *Div 3 Unavailability considered in case 3.* *Div 2 Unavailability is not allowed by TS.*
2	No planned maintenance or testing activities are scheduled in Scriba Substation, the NMP2 115kV switchyard, or the 115kV power supply lines and transformers which could cause a line outage or challenge offsite power availability.	Switchyard Maintenance W/O Line 5 W/O Line 6 W/O Reserve Transformer A W/O Reserve Transformer B W/O Res A & Line 5 W/O Res B & Line 6
3	The High Pressure Core Spray (HPCS) system is available and no planned maintenance or testing activities are scheduled.	W/O Div 3
4	The Reactor Core Isolation Cooling (RCIC) system is available and no planned maintenance or testing activities are scheduled.	W/O RCIC

ATTACHMENT 1

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Case #	Tier 2 Equipment Restrictions	Sensitivity Case
5	The NMP2 and NMP1 diesel-driven fire pumps (DFP) and the cross-tie between the NMP2 and NMP1 fire protection water supply systems are available to provide a backup cooling water supply to the Division 3 DG and no planned maintenance or testing activities are scheduled.	W/O U1 DFP W/O U2 DFP
6	The Division 1 and Division 2 residual heat removal (RHR) pumps and the low pressure core spray (LPCS) pump are available and no planned maintenance or testing activities are scheduled.	W/O RHR A W/O RHR B W/O LPCS W/O RHR B & LPCS
7	Both divisions of the redundant reactivity control system and the standby liquid control system (equipment required for mitigation of anticipated transients without scram (ATWS) events) are available and no planned maintenance or testing activities are scheduled.	W/O ATWS Div 1 W/O ATWS Div 2 W/O Standby Liquid Control System (SLCS) Div 1 W/O SLCS Div 2
8	The stability of existing and projected grid conditions will be confirmed prior to planned entry into the extended DG CT by contacting the transmission system operator.	N/A *Bounded by case 2.*
9	Operating crews will be briefed on the DG work plan. As a minimum, the briefing will include the following important procedural actions that could be required in the event a Loss of Offsite Power (LOOP), Station Blackout (SBO), or fire condition occurs:	-
	a Alignment of the fire protection water supply system to provide cooling water to the Division 3 DG.	*No improved human error probability (HEP) was credited.*
	b Establishing the cross-connection to allow the Division 3 DG to power either Division 1 or Division 2 loads.	
	c Utilizing the portable generator as a backup source of AC power to one of the Division 1 or Division 2 battery chargers.	
	d Utilizing the portable power supplies to maintain operability of the safety relief valves (SRVs).	ZOSVL1
	e Closing containment isolation valves in the drywell floor drain and equipment drain lines. PRA operator actions ZIS03 (SBO) and ZIS05 (Fire). ZIS03 - Operator fails to locally close equipment and floor drain motor operated valves (MOVs) in the reactor building early in the SBO event. ZIS05 – Operator fails to locally close equipment and floor drain MOVs in the reactor building early in the Fire event.	ZIS03 ZIS05

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RESPONSE TO NRC ACCEPTANCE REVIEW COMMENTS REGARDING THE PROPOSED EXTENSION OF THE COMPLETION TIME FOR AN INOPERABLE DIESEL GENERATOR

Items 1 through 7 were credited by removing maintenance unavailability for the subject systems/equipment. Item 8 was credited qualitatively only by not increasing the HEP during the extended DG CT. For Items 9a, 9b, and 9c, no improved HEP was credited. Sensitivity analyses have been performed for Items 2 through 7, 9d, and 9e (Item 1 is excluded since TS 3.8.1 requires specific actions with two or more DGs inoperable). The results for Items 2 through 7 are presented in Tables 5-1a and 5-1b below.

Table 5-1a: Sensitivity Results, With and Without Protected Equipment

Value	Switchyard											
	W/O Line 5	W/O Line 6	W/O RES A	W/O RES B	W/O LINE 5 & RES A	W/O LINE 6 & RES B	W/O DIV 3	W/O RCIC	W/O U1 DFP	W/O U2 DFP	With Protected Equipment	Accept. Criteria
	2a	2b	2c	2d	2e	2f	3	4	5a	5b		
ΔCDF_{ave}	4.2E-07	4.1E-07	7.0E-07	7.2E-07	7.1E-07	7.2E-07	1.8E-06	3.2E-06	3.1E-07	4.6E-07	2.9E-07	<1E-6
$\Delta LERF_{ave}$	2.5E-08	3.8E-08	4.6E-08	3.8E-08	4.7E-08	3.9E-08	1.4E-07	2.8E-07	2.5E-08	3.7E-08	2.2E-08	<1E-7
$ICCDP_1$	3.5E-07	3.3E-07	8.2E-07	3.4E-07	8.3E-07	3.5E-07	1.4E-06	3.1E-06	2.4E-07	3.5E-07	2.2E-07	<5E-7
$ICCDP_2$	4.5E-07	4.6E-07	5.2E-07	1.0E-06	5.2E-07	1.0E-06	2.1E-06	3.2E-06	3.6E-07	5.3E-07	3.3E-07	<5E-7
$ICLERP_1$	2.2E-08	2.4E-08	6.1E-08	2.4E-08	6.1E-08	2.4E-08	1.1E-07	2.7E-07	2.1E-08	3.0E-08	1.9E-08	<5E-8
$ICLERP_2$	2.6E-08	5.0E-08	2.8E-08	4.9E-08	2.8E-08	5.0E-08	1.7E-07	2.7E-07	2.7E-08	4.1E-08	2.4E-08	<5E-8

Table 5-1b: Sensitivity Results, With and Without Protected Equipment

Value	W/O RHS A	W/O RHS B	W/O LPCS	W/O RHS B & LPCS	W/O ATWS DIV 1	W/O ATWS DIV 2	W/O SLCS A	W/O SLCS B	With Protected Equipment	Acceptance Criteria
	6a	6b	6c	6d	7a	7b	7c	7d		
ΔCDF_{ave}	4.0E-06	6.8E-07	3.9E-07	7.9E-07	2.9E-07	2.9E-07	2.9E-07	2.9E-07	2.9E-07	<1E-6
$\Delta LERF_{ave}$	4.2E-08	3.1E-08	3.7E-08	4.3E-08	2.3E-08	2.3E-08	2.3E-08	2.2E-08	2.2E-08	<1E-7
$ICCDP_1$	1.3E-06	9.3E-07	2.5E-07	9.6E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	<5E-7
$ICCDP_2$	6.4E-06	3.7E-07	5.0E-07	5.4E-07	3.4E-07	3.3E-07	3.4E-07	3.3E-07	3.3E-07	<5E-7
$ICLERP_1$	3.5E-08	3.5E-08	3.2E-08	4.3E-08	1.9E-08	2.0E-08	1.9E-08	2.0E-08	1.9E-08	<5E-8
$ICLERP_2$	4.6E-08	2.5E-08	3.8E-08	4.0E-08	2.5E-08	2.4E-08	2.5E-08	2.4E-08	2.4E-08	<5E-8

Table 5-2 provides risk metrics without any of the credited compensatory operator actions, 9d, 9e (SBO), and 9e (Fire), and also with each action considered individually. Each of these cases assumes the Tier 2 equipment restrictions (protected equipment) are applied.

Table 5-2: Sensitivity Results, With and Without Compensatory Operator Actions

Value	Without Comp	With ZOSVL1	With ZIS03	With ZIS05	With All Comp	Acceptance Criteria
		9d	9e (SBO)	9e (Fire)		
ΔCDF_{ave}	3.7E-07	2.9E-07	3.7E-07	3.7E-07	2.9E-07	<1E-6
$\Delta LERF_{ave}$	1.0E-07	6.2E-08	8.8E-08	4.5E-08	2.2E-08	<1E-7
$ICCDP_1$	3.3E-07	2.2E-07	3.3E-07	3.3E-07	2.2E-07	<5E-7
$ICCDP_2$	3.8E-07	3.3E-07	3.8E-07	3.8E-07	3.3E-07	<5E-7
$ICLERP_1$	1.2E-07	5.6E-08	1.1E-07	4.0E-08	1.9E-08	<5E-8
$ICLERP_2$	7.6E-08	6.3E-08	5.6E-08	4.7E-08	2.4E-08	<5E-8

Comment 6

The risk analyses are dependent upon the once-per-2-year use of the extended completion times (CTs), but there is no justification as to why this assumption is valid. The licensee proposes to control voluntary use of the CT to once-per-2-years, but this is to be addressed in the TS bases, not in the TS action. Emergent repairs may result in additional use of the extended CT. The licensee will need to provide a technical justification for this assumption, and will need to provide sensitivity studies to address emergent repair use of the extended CT considering the increased probability of common cause failures (consistent with RG 1.177, Appendix A).

Response

As discussed in Section 2.2 of the submittal, the proposed amendment is desired to permit required DG inspections, maintenance, and overhauls to be scheduled and performed online. Either a planned 2-year inspection or a planned 6-year overhaul is scheduled once every 2 years for each DG (see the table in the response to Comment 7 below). This schedule for planned maintenance activities forms the basis for the assumption utilized in the risk assessment for the proposed amendment. This assumption is consistent with other similar license amendment requests that have been previously reviewed and approved by the NRC (e.g., River Bend Station – NRC letter dated September 25, 2002, Accession No. ML022590314; Columbia Generating Station – NRC letter dated April 14, 2006, Accession No. ML061000672; and Prairie Island Nuclear Generating Plant – NRC letter dated May 30, 2007, Accession No. ML071310023).

The common cause potential during the extended CT was considered. The common cause factors for the DGs are part of the results of determining the baseline risk metric values. However, TS 3.8.1 Required Action B.3.1 requires that within 24 hours, a determination be made that the operable DGs are not inoperable due to common cause failure. This TS requirement is unchanged by the proposed TS amendment. No additional common cause failure potential or HEP for incorrectly determining if a common cause was present has been added to the risk evaluation for the proposed amendment.

The DG extended CT risk evaluation assumes that a common cause failure does not exist due to the TS requirement to perform this common cause evaluation or, alternatively, to perform an operability test on the operable DGs. If the common cause determination method is by evaluation and is not sufficiently determinate as to whether a common cause failure exists, TS 3.8.1 Required Action B.3.2 allows testing to verify that the potential common cause is not impacting the operable DGs. If the common cause evaluation determines that the cause is likely to impact an operable DG, the TS actions allow a much shorter period to rectify the common cause inoperability or a plant shutdown would be required, regardless of the risk evaluation results that include an increased common cause potential. Specifically, TS 3.8.1 Required Action E.1 would require restoration of one DG to operable status within 2 hours for a Division 1 and Division 2 DG common cause and within 24 hours if the Division 3 DG is made inoperable by the common cause. Failure to restore a DG to operable status within these much shorter CTs would result in a required plant shutdown. Thus, for an actual common cause condition, the TS would preclude using the extended DG CT, unless the common cause condition is rectified. Based on these TS requirements, no PRA model adjustment is made to reflect an increased potential for common cause failure if one DG is out of service for corrective maintenance.

To conservatively bound uncertainty associated with common cause assumptions a sensitivity analysis with the following assumptions was performed:

- All extended diesel maintenance events were assumed to be corrective. Note that the last time NMP2 DGs required corrective maintenance was for the Division 1 DG in 2006; the next previous failure was in 1995.
- There is a 10% chance that common cause will not be correctly assessed in accordance with TS 3.8.1. The current value for DG Division 1 and 2 common cause for start and run were summed and multiplied by 0.1, then added to the Division 1 and Division 2 failure to start.

The risk metrics for this sensitivity case remain within the acceptance guidelines of RG 1.174 and RG 1.177.

Table 6-1: Sensitivity Results, Div 1/2 Common Cause

Value	Without CCF Adjustment	DG Start Failure + CCF	Acceptance Criteria
ΔCDF_{ave}	2.9E-07	3.09E-07	<1E-6
$\Delta LERF_{ave}$	2.2E-08	2.47E-08	<1E-7
$ICCDP_1$	2.2E-07	2.39E-07	<5E-7
$ICCDP_2$	3.3E-07	3.54E-07	<5E-7
$ICLERP_1$	1.9E-08	2.11E-08	<5E-8
$ICLERP_2$	2.4E-08	2.63E-08	<5E-8

Electrical Engineering Review

Comment 7

In the LAR, the licensee did not provide adequate justification for amending TS Section 3.8.1 to extend the CT for an inoperable Division 1 or 2 diesel generator (DG) from 72 hours to 14 days. Specifically, the licensee states, "the 2-year DG inspections (which typically require 5 days to complete) and the 6-year DG overhauls (which typically require 7 days to complete)." Provide the basis for the proposed extended CT of 14 days.

Response

The following table summarizes actual durations for 2-year DG inspections and 6-year DG overhauls performed for the NMP2 Division 1 and 2 DGs during the last three refueling outages.

Refueling Outage / Year	Approximate Actual Maintenance Duration			
	Division 1 DG		Division 2 DG	
	2-Yr. Inspection	6-Yr. Overhaul	2-Yr. Inspection	6-Yr. Overhaul
RF010 / 2006	7.3 days	---	---	7.6 days
RF011 / 2008	---	8 days	5.3 days	---
RF012 / 2010	8 days	---	8 days	---

The maintenance activities described in the above table were all performed during refueling outages; thus, the durations (ranging from approximately 5 to 8 days) were determined by outage schedules rather than TS CT requirements. As discussed in Section 3.2.6 of the submittal, the NMPNS practice is to schedule online maintenance activities (both preventive and corrective) so that they are completed within one-half of the TS CT limit. This practice is acknowledged in RG 1.177 (Section A.2.3.1). This allows sufficient time to resolve unexpected conditions discovered during performance of the maintenance or during subsequent post-maintenance testing so that subsequent actions required by the TS (e.g., plant shutdown) are avoided. Activities that require or result in exceeding 50 percent of the TS CT limit are classified as risk significant, requiring application of risk management actions in accordance with the NMPNS configuration risk management program.

Having an extended TS CT for an inoperable DG that is of sufficient duration also improves the effectiveness of the allowed maintenance period. A significant portion of on-line maintenance activities is associated with preparation and return-to-service activities, such as tagging, fluid system drain down, and fluid system fill and vent. The duration of these activities is relatively constant. A longer CT duration allows more maintenance to be accomplished during a given online maintenance period, thereby improving maintenance efficiency and avoiding multiple entry into and exiting from TS LCO Required Actions to complete desired activities.

The request to extend the TS CT for an inoperable Division 1 or Division 2 DG from 72 hours to 14 days is consistent with the above discussion, i.e., the 14-day CT is twice the expected duration for performing 2-year inspections or 6-year overhauls of the DGs while on line. In addition, the risk evaluation performed in support of the proposed amendment concluded that the increase in risk is small and consistent with the guideline values in RG 1.177. The NRC has previously reviewed and approved similar license amendment requests to extend the TS CT for an inoperable DG to 14 days (e.g., River Bend Station – NRC Letter dated September 25, 2002, Accession No. ML022590314; Beaver Valley Power Station – NRC letter dated September 29, 2005, Accession No. ML052720259; Columbia Generating Station – NRC letter dated April 14, 2006, Accession No. ML061000672; and Prairie Island Nuclear Generating Plant – NRC letter dated May 30, 2007, Accession No. ML071310023).

Comment 8

It appears that the capacity of the proposed alternate alternating current (AC) power source (High Pressure Core Spray Emergency DG) to replace the inoperable Emergency DG (Division 1 or 2) is not adequate to support a loss-of-offsite power (LOOP) event with a unit trip. Considering the changes in electric grid performance post-deregulation, the duration of LOOP events has increased, and the probability of a LOOP as a consequence of a reactor trip has increased. As a deterministic measure to ensure adequate defense-in-depth, given the changes in the electric grid performance post-deregulation, the NRC staff requires the replacement power source has adequate capacity of handling station blackout (SBO) and LOOP loads, to supplement the existing EDGs during the extended 14-day allowed outage time. Provide justification to demonstrate that the proposed diesel is adequate to maintain the defense-in-depth philosophy of the emergency power system.

Response

The capacity of the Division 3 HPCS DG has been evaluated and is capable of supplying the electrical loads needed for LOOP and SBO events. The cross-connection alignment of the Division 3 DG to either the Division 1 or Division 2 emergency bus would only be utilized in the event that a LOOP occurs when the Division 1 or Division 2 DG is inoperable (e.g., for maintenance activities requiring entry into the proposed extended TS CT) and the redundant DG fails to operate. This effectively creates an SBO condition.

The Division 3 DG has a continuous rating of 2600 kW and a 2000-hour rating of 2850 kW, as described in NMP2 Updated Safety Analysis Report (USAR) Section 8.3.1.1.2. The Division 3 emergency bus maximum load is 2540 kW (reference USAR Table 8.3-3). In the cross-connection alignment, the HPCS pump (2433 kW) will not be operating; thus, the remaining Division 3 emergency bus load is approximately 107 kW.

The loads powered by the Division 1 DG for a LOOP with unit trip condition are listed in USAR Table 8.3-1 (organized by power source) and are summarized in USAR Table 8.3-5 (as a function of time from inception of the event). The loads powered by the Division 2 DG for a LOOP with unit trip condition are listed in USAR Table 8.3-2 (organized by power source) and are summarized in USAR Table 8.3-6 (as a function of time from inception of the event). The loads powered by the Division 1 and Division 2 DGs consist of both automatically connected and manually connected loads, as discussed below.

Division 1

For the first two hours of the LOOP with unit trip condition, the maximum Division 1 running load is 2753 kW. This includes one automatically started Service Water (SW) pump, one manually started SW pump, and the manually started RHR pump A (assumed to occur one hour after event inception). The LPCS pump, which is also powered from the Division 1 emergency bus, is not operating since a concurrent loss of coolant accident (LOCA) need not be assumed to occur. In accordance with existing NMP2 SBO special operating procedures, only a single Division 1 SW pump should be in operation when the Division 3 DG is cross-connected to the Division 1 emergency bus. Thus, the Division 1 loads to be powered by the Division 3 DG for the first two hours of the LOOP with unit trip condition would be:

2753 kW + 107 kW (Division 3 load) – 442 kW (one SW pump load) = 2418 kW

After the first two hours of the LOOP with unit trip condition, the DG loading analyses assume that the Division 1 Spent Fuel Pool (SFP) cooling system pump (330 kW) is manually started to restore cooling flow to the spent fuel pool. This results in a total Division 1 load of 2748 kW, which is less than the 2000-hour rating of the Division 3 DG. Based on actual spent fuel pool cooling requirements, this action is not actually needed until approximately 5 hours (or longer) after inception of the event (depending on the spent fuel pool initial water temperature and spent fuel heat load).

Division 2
For the first two hours of the LOOP with unit trip condition, the maximum Division 2 running load is 2679 kW. This includes one automatically started SW pump, one manually started SW pump, and the manually started RHR pump B (assumed to occur one hour after event inception). RHR pump C, which is also powered from the Division 2 emergency bus, functions only in the low pressure coolant injection (LPCI) mode and is not operating since a concurrent LOCA need not be assumed to occur. In accordance with existing NMP2 SBO special operating procedures, only a single Division 2 SW pump should be in operation when the Division 3 DG is cross-connected to the Division 2 emergency bus. Thus, the Division 2 loads to be powered by the Division 3 DG for the first two hours of the LOOP with unit trip condition would be:

2679 kW + 107 kW (Division 3 load) – 442 kW (one SW pump load) = 2344 kW

After the first two hours of the LOOP with unit trip condition, the DG loading analyses assume that the Division 2 SFP cooling system pump (330 kW) is manually started to restore cooling flow to the spent fuel pool. This results in a total Division 2 load of 2674 kW, which is less than the 2000-hour rating of the Division 3 DG. Based on actual spent fuel pool cooling requirements, this action is not actually needed until approximately 5 hours (or longer) after inception of the event (depending on the spent fuel pool initial temperature and heat load).

Based on the above evaluation, it is concluded that the Division 3 DG is capable of supplying either the Division 1 or Division 2 electrical loads needed for a LOOP or SBO event, including the powering of one RHR pump aligned in either the shutdown cooling or suppression pool cooling modes of operation to remove reactor decay heat. As described in Section 3.1.1 of the submittal, the Shift Manager will determine the priority for energizing the safe shutdown loads based on plant needs while assuring that the Division 3 DG loading limits are not exceeded, as directed by the existing NMP2 SBO special operating procedures. Therefore, capability for cross-connecting the Division 3 DG to either the Division 1 or Division 2 emergency bus provides defense-in-depth in the event that a LOOP occurs while the Division 1 or Division 2 DG is in the proposed extended TS CT.

ATTACHMENT 2

COMPARISON OF THE NMP2 FIRE PRA MODEL TO THE

TECHNICAL ELEMENTS OF

REGULATORY GUIDE 1.200, REVISION 2, SECTION 1.2.4

ATTACHMENT 2

COMPARISON OF THE NMP2 FIRE PRA MODEL TO THE TECHNICAL ELEMENTS OF REGULATORY GUIDE 1.200, REVISION 2, SECTION 1.2.4

FIRE - RG 1.200 Rev 2 Technical Elements		
Element	**Technical Characteristics and Attributes**	**NMP2 Assessment**
Plant Boundary Definition and Partitioning	1. Global analysis boundary captures all plant locations relevant to the fire PRA. 2. Physical analysis units are identified by credited partitioning elements that are capable of substantially confining fire damage behaviors.	1. All plant locations relevant to the fire probabilistic risk assessment (PRA) are included in the analysis. 2. The fire compartments are delineated in the same manner as used for the Appendix R analysis. Definitions are provided in Nine Mile Point Unit 2 (NMP2) updated safety analysis report (USAR) Section 9A.2.4. The physical barriers included in the analysis confine damage from fires. These compartments include buildings in the protected area that can impact plant operation and are listed in Table A2-1A. These same compartments provide the basis for analyzing the effects of fires and documenting the analysis.
Equipment Selection	1. Equipment is selected for inclusion in the plant response model that will lead to a fire-induced plant initiator, or that is needed to respond to such an initiator (including equipment subject to fire-induced spurious actuation that affects the plant response). 2. The number of spurious actuations to be addressed increases according to the significance of the consequence (e.g., interfacing systems LOCA).	1. Electrical equipment in the internal events PRA and Appendix R safe shutdown analysis (SSA) provide the basis for equipment needed for the fire PRA model. Support system failures were considered with regard to initiating event potential for each compartment. If no support system initiator was identified for a compartment, plant trip was generally assumed due to turbine trip or reactor trip unless these causes could be excluded. The equipment selection includes the impact of single spurious operation. A multiple spurious operation (MSO) review has been recently completed as well and discussed in 2 below. ***GAP**: Since the individual plant examination for external events (IPEEE), new equipment has been added to the internal events PRA. An MSO review (Attachment A2-C) was performed, as well as a review of modifications since the IPEEE. Neither of these reviews identified issues that would impact the submittal. As a further review, the change tracking database was searched and identified six cable modifications that could have potentially impacted modeled components. These six modifications were evaluated as not having an impact.* 2. Spurious actuations were considered in the IPEEE. Consequential events that were considered in the evaluation of spurious actuations include interfacing system loss of coolant accident (ISLOCA), reactor pressure vessel (RPV) overfill and vessel isolation. ISLOCA is unlikely since power is removed from residual heat removal (RHR) valves to ensure this event is extremely unlikely. RPV overfill and vessel isolation failures are unlikely and are not considered significant relative to the diesel generator (DG) allowed outage time (AOT) delta risk assessment. Most recently, the industry generic MSO list was reviewed and MSOs 5a, 5f, 5g, 5h and 5i were determined to be related to this application (DG events). ***GAP**: A detailed evaluation of all MSOs for inclusion in the PRA has not been completed. However, the generic list of MSOs was reviewed to select those that could affect alternating current (AC) power to show that the risk of applicable scenarios is expected to be low for this application. This evaluation is documented in Attachment A2-C. Also, a review of condition reports initiated since the IPEEE based on a search for multiple spurious operation identified no events that were relevant to NMP2.* Spurious indications that can cause undesirable operator actions were also reviewed. Procedures typically have operators look at another indication to verify the condition before taking a potentially undesirable action and/or the operators are instructed to not trip the equipment if the equipment is required. Reactor Core Isolation Cooling (RCIC) and High Pressure Core Spray (HPCS) are considered most important, as they provide immediate RPV level control. These systems were checked to ensure the potential for undesirable actions is low.

FIRE - RG 1.200 Rev 2 Technical Elements		
Element	**Technical Characteristics and Attributes**	**NMP2 Assessment**
	3. Instrumentation and support equipment are included.	3. Physical separation has been identified for instrumentation and support equipment needed for Appendix R; thus no additional instruments are explicitly modeled. ***GAP***: *A Human Error Probability (HEP) review to determine if non-Appendix R instruments need modeling was performed. Ooperator actions with high risk achievement worth (RAW) values associated with the proposed DG AOT extension were evaluated to determine whether they have adequate instrumentation to support the HEP. Based on this review, it is unlikely that a fire will significantly impact instrumentation and operator response for these important actions. The most important operator actions (e.g., emergency depressurization) depend on Appendix R spatially separated instruments and other actions have been reviewed (see Attachment A2-D).*
Cable Selection	Cables that are required to support the operation of fire PRA equipment (defined in the equipment selection element) are identified and located.	Cables that are required to support PRA equipment were identified and located. The equipment in the area impacted by fire was considered lost. The identification of cables is based on a progressive analysis used in the fire analysis as summarized below: • A computerized spatial database was developed such that all plant cables and components in a fire compartment can be identified, including their raceways. A review of modifications (see Equipment Selection) determined that no significant changes have occurred. ***GAP***: *Although there may have been some changes to cables and routing since the IPEEE was performed in 1994, in general, components, junction boxes and panels where cables are routed have not been relocated. Therefore, any new cables would be routed in the same manner through the same fire zones/fire areas as was documented in the cable original database and, as such, there is no impact on the fire PRA.* • Cables that are required for PRA were identified for non-Appendix R equipment such as offsite power, feedwater, main condenser, and their support systems. These cables were queried against the spatial database to identify those compartments containing these impacts. • Initially, all possible Appendix R equipment impacts are assumed for each compartment. In other words, if the compartment is a Division 1 area, Division 1 equipment is assumed to fail, except in certain cases where it was relatively straightforward by use of the spatial database and Appendix R analysis to limit the impact. After the initial screening analysis, additional detailed cable evaluations and impacts, including their location, were included to better define realistic scenarios for inclusion in the PRA model.
Qualitative Screening *(Optional Element)*	Screened out physical analysis units represent negligible contributions to risk and are considered no further.	The screened out physical analysis units represent negligible contributions. Both qualitative and quantitative screening is conducted for each compartment with results summarized in Table A2-1A and A2-1B.

FIRE - RG 1.200 Rev 2 Technical Elements		
Element	**Technical Characteristics and Attributes**	**NMP2 Assessment**
Fire PRA Plant Response Model	1. Based upon the internal events PRA, the logic model is adjusted to add new fire-induced initiating events and modified or new accident sequences, operator actions, and accident progressions (in particular those from spurious actuations).	1. The internal events PRA model is used to represent the plant response for fire initiating events. The transient model is used as well, as its transfer to medium LOCA (MLOCA) (stuck open safety relief valve (SRV)), station blackout (SBO) and anticipated transient without scram (ATWS) models. Tables A2-1A and A2-1B summarize the impacts for the initial screening analysis. Table A2-2 summarizes the initiating events determined to be risk important and included in the PRA after the more detailed compartment evaluations. The impacts of each initiating event are provided in Table A2-3.
	2. Inapplicable aspects of the internal events PRA model are bypassed.	2. Aspects of the internal events model are bypassed in the fire portion of model; e.g. large and small LOCA, ISLOCA, and breaks outside containment (BOC) do not apply to fires, and therefore are not utilized.
Fire Scenario Selection and Analysis		The screening scenarios are identified in Table A2-1A and A2-1B, which summarize the total ignition frequency determined for each compartment, the initiating event identified for each compartment, and model impacts assuming everything is affected by the fire in the compartment. For those compartments that did not screen, additional analyses were conducted including consideration of the location of ignition sources, targets, fire growth and propagation, and fire suppression (Attachment A2-B). As a result of these evaluations, risk important scenarios were identified for inclusion into the PRA model (Tables A2-2 and A2-3 summarize the results of these evaluations). Four scenarios were identified for the main control room; each scenario includes consideration of operators remaining in the main control room and control room abandonment. Walkdowns were conducted in support of the analysis and to consider multi-compartment fire propagation. Multi-compartment fire scenarios were judged to be low risk and no such scenarios are included in the PRA model.
	1. Fire scenarios are defined in terms of ignition sources, fire growth and propagation, fire detection, fire suppression, and cables and equipment ("targets") damaged by fire.	1. Walkdowns were performed to identify ignition sources for all compartments. Fire growth, propagation, fire detection, fire suppression and equipment damaged by fire were evaluated for unscreened compartments.
	2. The effectiveness of various fire protection features and systems is assessed (e.g., fixed suppression systems).	2. The effectiveness of fire protection was assessed. Fire detection is provided in each compartment evaluated in the fire analysis. For those areas requiring more detailed analysis (i.e., did not screen out as part of the initial screening analysis), detection and suppression capabilities were reviewed, as well as how these systems are credited in the analysis. Some areas also have automatic suppression systems or manual suppression capabilities. Fire growth for applicable fires is in accordance with the IPEEE. ***GAP**: The only major change since the IPEEE is that auto initiation of the CO2 system for the switchgear rooms in now manual. This was considered in the fire growth evaluation and in the detailed evaluation (Attachment A2-B). The evaluation concluded that this change did not have a significant impact. Also, doubling the assumed failure probability of automatic actuation showed a very small increase in risk and did not change the conclusions of the analysis for the proposed amendment.*
	3. Appropriate fire modeling tools are applied.	3. The Electric Power Research Institute (EPRI) modeling tool, Fire Induced Vulnerability Evaluation (FIVE), was used.

FIRE - RG 1.200 Rev 2 Technical Elements		
Element	**Technical Characteristics and Attributes**	**NMP2 Assessment**
	4. The technical basis is established for statistical and empirical models in the context of the fire scenarios (e.g., fire brigade response).	4. Where explicit credit is taken for detection and suppression in the detailed analysis, an unreliability of 0.05 per demand is used for automatic detection and suppression. A plant specific systems analysis to estimate fire protection system reliability was not deemed necessary. No significant reliability problems have been observed at NMP2. Very Early Smoke Detection Apparatus (VESDA) has been installed in several areas in the plant and is being installed in the normal switchgear rooms. This is incipient detection that provides more time for operator or fire brigade response. This system has not been credited in the PRA. Fire brigade response is considered in the evaluation of fire zones that did not screen. The IPEEE evaluated fire brigade staffing, equipment, drills and training. There have been no significant changes to this IPEEE information.
	5. Scenarios involving the fire-induced failure of structural steel are identified and assessed (at least qualitatively).	5. Based on NMP2 design (see USAR Section 9.5 and Appendix 9A), structural steel is qualified as a 3-hour barrier which includes fire proofing. No scenarios that impact structures in a way that significant impacts can occur have been identified.
Fire Ignition Frequencies	1. Frequencies are established for ignition sources and consequently for physical analysis units.	1. The frequency of a fire was developed for each compartment. Quantification of the ignition sources in the plant and the cumulative fire ignition frequency is based on those hazards and the EPRI fire incident database is discussed in the FIVE methodology (Attachment 10.3 of EPRI TR100370). The total fire ignition frequency developed from this analysis for each compartment is provided in Table A2-1A. These frequencies were used in the initial screening analysis. The contributing ignition sources for each compartment developed from this analysis are considered in the detailed analysis of compartments when they could not be screened out using other methods.
	2. Transient fires should be postulated for all physical analysis units regardless of administrative controls.	2. Transient fire frequency was considered as part of Item 1 above.
	3. Appropriate justification must be provided to use nonnuclear experience to determine fire ignition frequency.	3. Nonnuclear experience was not used. EPRI TR 100370, Fire-Induced Vulnerability Evaluation (FIVE), is based on nuclear plant experience. ***GAP**: The latest ignition data was not used, but updating the data will not impact the result. Ignition frequencies are as derived from Table 1.2 of FIVE (Attachment 10.3 of EPRI TR 100370) and have not been updated to recent data. Attachment A2-A summarizes a comparison with recent updated data in EPRI 1016735 for some key ignition sources in the NMP2 PRA. Also, the present frequencies are judged to be reasonable (if not conservative) based on present methods of counting cabinets. The fire frequency will be comparable with no significant change once the frequency is adjusted for these compartments. A lower frequency for main control board fires would be calculated if more current data and methods were applied.*
Quantitative Screening	1. Physical analysis units that are screened out from more refined quantitative analysis are retained to establish CDF and LERF/LRF.	1. Both qualitative and quantitative screening is conducted with results summarized in Tables 2A-1A and 2A-1B. A containment performance evaluation was conducted to provide confidence that LERF was at least an order of magnitude less than core damage frequency (CDF). ***GAP**: A CDF value less than 1E-6 for a complete compartment was used as a screening value recognizing that a more detailed analysis would result in a CDF closer to 1E-7 or less. Table A2-1A was updated using the latest Computer Aided Fault Tree Analysis (CAFTA)*

FIRE - RG 1.200 Rev 2 Technical Elements		
Element	**Technical Characteristics and Attributes**	**NMP2 Assessment**
		*model for the same impacts and frequencies using a CDF screening value of 1E-7. Several compartments screened out and 3 new events were added, refer to Table A2-2. These new events were determined to be non-consequential based on the detailed evaluation in Attachment A2-B. The fire CDF values are lower in **ALL** the cases.* *Large early release frequency (LERF) screening was not performed for the IPEEE. However, a new screening assessment was performed using the current PRA and using the same fire zone impacts identified in Table A2-1A. This screening used a LERF cutoff of 1E-8. No new zones were unscreened (see Table A2-1B).* ***GAP**: Compartment screening was not retained and reported as a part of the total plant fire risk in the fire risk quantification. This is judged not to be significant based on the low screening value and other sensitivities considered for this application.*
	2. Typically, those fire PRA contributions to CDF and LERF/LRF that are established in the quantitative screening phase are conservatively characterized.	2. PRA contributors to CDF and LERF were conservatively characterized. Initial screening is very conservative as it assumes that all cables in a compartment and equipment are impacted.
Circuit Failure Analysis	The conditional probability of occurrence of various circuit failure modes given cable damage from a fire is based upon cable and circuit features.	Components were assumed to fail with a probability of 1.0 for cases were a cable existed in a compartment that could impact a component. As such, detailed circuit analyses were not required. ***GAP**: Spurious operation was assessed using a probability of 0.1 in the detailed evaluation without circuit failure analysis (see Attachment A2-B). However, this has no impact on the screening analysis conclusions.*
Postfire Human Reliability Analysis	1. Operator actions and related post-initiator HFEs, conducted both within and outside of the main control room, are addressed.	1. Human reliability was evaluated for response to control room fires for both the inside control room and the abandonment case. ***GAP:** The most important panel for this application (852) has been evaluated and includes two scenarios involving offsite power and the DGs. Other panels were determined to be less consequential based on a cabinet Failure Modes and Effects Analysis (FMEA) evaluation in the IPEEE, Table 4.6-2, Control Room Panels Evaluation, and their exclusion does not impact this application.*
	2. The effects of fire-specific procedures are identified and incorporated into the plant response model.	2. Fire specific procedures are identified, reviewed and incorporated specifically for control room abandonment. No changes were identified for other fire scenarios. ***GAP**: Procedure changes have been made since the IPEEE. These procedures were reviewed and confirmed that IPEEE assumptions are still valid. The IPEEE also discusses fire brigade staffing, equipment, drills and training. This information is still valid.*
	3. Plausible and feasible recovery actions, assessed for the effects of fire, are identified and quantified.	3. Plausible and feasible recovery actions, assessed for the effects of fire, are retained and used the same as HEP values as in the internal events model, or the associated action is failed (no recovery credited).

FIRE - RG 1.200 Rev 2 Technical Elements		
Element	**Technical Characteristics and Attributes**	**NMP2 Assessment**
	4. Undesired operator actions resulting from spurious indications are addressed.	4. The IPEEE HEP analysis assumed that procedures typically have operators look at another indication to verify the condition before taking a potentially undesirable action and/or the operators are instructed to not trip the equipment if the equipment is required. ***GAP:*** *Evaluation of undesired operator actions resulting from spurious indications that are important to this application was performed. See Equipment Selection review above.*
	5. Operator actions from the internal events PRA that are retained in the fire PRA are assessed for fire effects.	5. Operator actions important for this application were assessed in Table A2-D.1 for fires external to the control room. The probability for certain important actions was increased by 10. This sensitivity study showed a minimal increase in risk and did not change the conclusions of the submittal (Table A2-D.2). ***GAP:*** *Human reliability for fires out in the plant external to the control room was not penalized for fires. A sensitivity analysis was performed on high importance operator actions that require a response of 30 minutes or less. The HEP for these actions was increased by a factor of 10 and the results show a negligible increase in risk and when included in the assessment for the amendment, the results were well within the criteria.*
Fire Risk Quantification	1. For each fire scenario, the fire risk results are quantified by combining the fire ignition frequency, the probability of fire damage and the conditional core damage probability (and CLRP/CLERP) from the fire PRA plant response model. 2. Total fire-induced CDF and LERF/LRF are calculated for the plant and significant contributors identified. 3. The contribution of quantitatively screened scenarios (from the quantitative screening element) is added to yield the total risk values.	1. Table A2-3 summarizes CDF and LERF results for the fire initiating events modeled in the PRA. These are the result of combining the fire initiating event frequency and conditional core damage and large early release frequency through the plant response model. 2. The submittal includes top cutsets and importance measures based on the integrated internal events- fire-seismic model. 3. Refer to Tables A2-1A and A2-1B. The screening is conservative and judged not to have an impact on the PRA.
Seismic Fire Interactions	1. Potential interactions resulting from an earthquake and a resulting fire that might contribute to plant risk are reviewed qualitatively. 2. Qualitative assessment verifies that such interactions have been considered and that steps are taken to ensure that the potential risk contributions are mitigated.	1. The IPEEE includes a qualitative review of potential seismic/fire interactions to ensure that there are no potentially important contributors to plant risk and steps have been taken to ensure that potentially important risk contributors are mitigated. 2. See Item 1 above.

FIRE - RG 1.200 Rev 2 Technical Elements		
Element	**Technical Characteristics and Attributes**	**NMP2 Assessment**
Uncertainty and Sensitivity	1. Uncertainty in quantitative fire PRA results because of parameter uncertainties are evaluated.	1. The submittal provides an assessment of uncertainty related to this specific application. Impact of parameter uncertainties is not necessary for this application due to compensatory measures, etc. In the IPEEE, sensitivities were performed for control room fires. *GAP: A comprehensive uncertainty analysis has not been performed for fires; however, application-specific sensitivity analyses have been performed and show the conclusions for the proposed amendment do not change.*
	2. Model uncertainties as well as the potential sensitivities of the results to associated assumptions are identified and characterized .	2. See Item 1 above. The assumptions are imbedded in the analysis (see Attachment A2-B) and have not been separated in the documentation. *GAP: This is a documentation issue for the future and does not impact the results for the proposed amendment.*

Table A2-1A: Initial Fire Area Screening Analysis Summary, CDF – 5/2010 Post IPEEE Update

Area	Zone	Description	Fire Freq	App R	Initiator	Screening Summary	System Impacts														
							OG	A1/2	RW	TW	AS	CN	FW	HS	IC	LA	LB	LC	LS	SV	CV
1	201SW	North Aux Bay-LPCS pump	4.8E-03	I	yes (1)	CDF <1E-7													X		
1	202SW	North Aux Bay-RHR A pump	3.1E-03	I	yes (1)	CDF <1E-7										X					
1	203SW	North Aux Bay-RHR HE 1A	2.4E-03	I	yes (1)	CDF <1E-7										X					
1	211SW	North Aux Bay-RHR & CCP HE	2.4E-03	I	yes (1)	CDF <1E-7										X			X		
1	221SW	North Aux Bay-SWP to CCP	3.1E-04	I	RWX	CDF <1E-7			X			X			X	X			X	I	M1
1	231SW	North Aux Bay-MCC area	9.9E-04	I	RWX	CDF <1E-7			X			X	X		X	X			X	I	M1
2	204SW	RCIC pump room	4.2E-03	I	no	RCIC unavailability insignificant									X						
3	206SW	South Aux Bay-RHR B HE	2.4E-03	II	yes (1)	CDF <1E-7											X				
3	207SW	South Aux Bay-RHR B pump	4.2E-03	II	yes (1)	CDF <1E-7											X				
3	208SW	South Aux Bay-LPCI C pump	3.6E-03	II	yes (1)	CDF <1E-7												X			
3	214SW	South Aux Bay-RHR HE 1B	3.4E-04	II	yes (1)	CDF <1E-7											X	X			
3	224SW	South Aux Bay-South access	2.4E-03	II	RWX	CDF <1E-7			X			X			X		X	X			
3	239SW	South Aux Bay-MCC area	9.9E-04	II	RWX	CDF <1E-7			X			X			X		X	X			M2
4	205NZ	HPCS pump room	4.7E-03	III	no	HPCS unavailability insignificant								X							
5	234NZ	Drywell	0.0E+00	(2)	(2)	(2)															
8	301NW	140 degree tunnel	1.5E-04	I	A1X	CDF<1E-7		A1				X	X								Air
8	302NW	35 degree tunnel	1.4E-05	I	A1X	CDF<1E-7		A1	X			X	X								Air
10	303NW	315 deg tunnel	1.2E-05	N	RWX	CDF<1E-7			X			X	X								
16	306.1NW	Div1/2 cable area-general area	1.6E-04	I	RWX	CDF<1E-7			X			X	X								Air
16	306.2NW	Document storage room	5.3E-04	N	no	no initiator or impact															
16	312NZ	Div 1/2 cable area-general area	2.2E-04	I	MSIV	CDF<1E-7						X			X						
16	321NW	Div 1 riser area	1.5E-04	I	A1X	CDF<1E-7	KAR	A1	X	X		X	X		X						Air
16	332NW	Div 1 cable chase West	1.5E-04	I	LOSP	CDF=6.92E-7	OG	A1	X	X	X	X	X		X						Air
16	352NW	Div 1 cable chase West	1.6E-04	I	LOSP	CDF=7.38E-7	OG	A1	X	X	X	X	X		X						Air
16	362.2NZ	Pipe tunnel (FA55 362NZ)	2.3E-04	I	RWX	<1E-7															
16	371NW	Div 1 cable chase West	1.5E-04	I	LOSP	CDF=6.92E-7	OG	A1	X	X	X	X	X		X						Air
17	305NW	Div 1 riser area	1.3E-05	I	RWX	CDF<1E-7			X	X		X	X		X						Air
17	322NW	Div 1 cable routing area	1.5E-04	I	A1X	CDF<1E-7	KAR	A1				X	X		X						Air
17	325NW	Div 1 cable routing area	1.3E-05	I	A1X	CDF<1E-7	KAR	A1							X						
17	333XL	Div 1 standby switchgear room	9.9E-04	I	A1X	CDF=1.22E-7	KAR	A1							X						DW
17	334NZ	Div 1 battery room	5.1E-04	I	D1X	CDF<1E-7 (D1 - Div 1 DC)									X						
17	343NZ	Remote shutdown room A West	1.5E-04	I	A1X	CDF<1E-7		A1							X						
17	NONEXX	Fire Protection Valve Room	2.3E-04	I	A1X	CDF<1E-7		A1													
18	304NW	230 degree tunnel	1.5E-04	II	A2X	CDF = 1.58E-7		A2				X		X							X
18	309NW	Cable chase East	1.3E-05	II	A2X	CDF < 1E-7		A2	X			X	X	X							
18	324NW	Div 2 riser area	1.5E-04	II	A2X	CDF = 1.58E-7	KBR	A2	X			X	X	X							X
18	337NW	Div 2/3 cable chase East	1.5E-04	II	A2X	CDF = 1.58E-7	KBR	A2	X		1B	X	X	X							X
18	359NW	Div 2/3 cable chase East	1.5E-04	II	A2X	CDF = 1.58E-7	KBR	A2	X		1B	X	X	X							X
18	377NW	Div 2/3 cable chase East	1.5E-04	II	A2X	CDF = 1.58E-7	KBR	A2	X			X	X	X							X
19	323NW	Div 2 cable routing area	1.5E-04	II	A2X	CDF = 1.58E-7	KBR	A2				X		X							X
19	326NW	Div 2 cable routing area	1.3E-05	II	A2X	CDF < 1E-7	KBR	A2						X							
19	335NZ	Div 2 battery room	5.1E-04	II	D2X	CDF < 1E-7 (D2 - Div 2 DC)															
19	336XL	Div 2 standby switchgear room	9.7E-04	II	A2X	CDF = 5.03E-7	KBR	A2	X		1B			X							
19	338NZ	Remote shutdown room B East	1.5E-04	II	A2X	CDF<1E-7		A2													
21	327NW	HPCS cable routing area	1.5E-04	III	no	HPCS unavailability insignificant								X							
21	342XL	HPCS Switchgear	9.8E-04	III	no	HPCS unavailability insignificant								X							
22	340NZ	Div 1 chiller	3.8E-03	I	no	No initiator or impact on PRA															
23	341NZ	Div 2 chiller	3.8E-03	II	no	No initiator or impact on PRA															
24	356NZ	PGCC relay (353,354,362SG)	2.3E-04	I & II	yes	CDF=2.3E-04detailed evaluation req'd		X													
24	357XL	PGCC computer room (358XG)	1.5E-04	I & II	yes	CDF=1.5E-04detailed evaluation req'd		X													

Table A2-1A: Initial Fire Area Screening Analysis Summary, CDF – 5/2010 Post IPEEE Update

Area	Zone	Description	Fire Freq	App R	Initiator	Screening Summary	System Impacts														
							OG	A1/2	RW	TW	AS	CN	FW	HS	IC	LA	LB	LC	LS	SV	CV
25	360NZ	Div 1 CR HVAC room	2.8E-03	I	no	No initiator or impact on PRA															
26	373.1NZ	Control Room (372-376)	9.9E-03	I & II	yes	CDF=9.9E-03 *[detailed evaluation req'd]*		X													
26	373.2NZ	Shift supervisors office	2.3E-04	I & II	yes	CDF=2.3E-04 *[detailed evaluation req'd]*		X													
26	373.3NZ	Training room	2.3E-04	I & II	yes	CDF=2.3E-04 *[detailed evaluation req'd]*		X													
27	378NZ	Div 2 CR HVAC room	2.5E-03	II	MSIV	CDF<1E-7						X									
28	401.1NZ	Div 1 diesel generator-CR	2.7E-03	I	no	DG unavailability insignificant		DG													
28	402.1SW	Div 1 diesel generator	2.9E-02	I	no	DG unavailability insignificant		DG													
29	401.2NZ	Div 2 diesel generator-CR	2.7E-03	II	no	DG unavailability insignificant		DG													
29	403.1SW	Div 2 diesel generator	2.9E-02	II	no	DG unavailability insignificant		DG													
30	401.3NZ	HPCS diesel control room	2.7E-03	III	no	DG unavailability insignificant								DG							
30	404.1SW	HPCS diesel generator	2.9E-02	III	no	DG unavailability insignificant								DG							
34	0NA	North reactor building	3.9E-02(4)	I		See Zones below															
34	212SW	North reactor building El 175	1E-2(4)	I	RWX	CDF = 1.58E-7			X				X		X	X			X		Air
34	222SW	North reactor building El 215	1E-2(4)	I	RWX	CDF = 1.58E-7			X			X	X		X	X			X	I	Air
34	232SW	North reactor building El 240	1E-2(4)	I	RWX	CDF = 2.48E-7		DG	X			X	X		X	X			X	I	Air
34	243SW	North reactor building El 261	1E-2(4)	I	RWX	CDF = 1.58E-7 (E1 - ECCS Div 1)			2 of 3			X	X		X	X			X		Air
34	252SW	North reactor building El 289	1E-2(4)	I	RWX	CDF = 1.58E-7			X			X	2 of 3		X	X			X		Air
34	261SW	North reactor building El 306	1E-2(4)	I	no	No initiator or impact on PRA															Air
34	271SW	North reactor building El 328 NW	1E-2(4)	I	RWX	CDF<1E-7			X			X									M1
34	273SW	North reactor building El 328 NE	1E-2(4)	I	no	No initiator or impact on PRA															
34/35	281NZ	North reactor building El 353 and above	1E-2(4)	I	no	No initiator or impact on PRA															
34	242NW	Track bay (same as FA98)	5.3E-04(4)	N	no	No initiator or impact on PRA															
35	0NA	South reactor building	3.8E-02(4)	II		See Zones below															
35	213SW	South reactor building El 175	1E-2(4)	II	RWX	CDF = 3.35E-6			X					X			X	X			
35	223SW	South reactor building El 215	1E-2(4)	II	RWX	CDF = 8.43E-6			X			X	X	X			X	X		II	X
35	238SW	South reactor building El 240	1E-2(4)	II	RWX	CDF = 3.35E-6			X			X	X	X			X	X		II	DW
35	245SW	South reactor building El 261	1E-2(4)	II	RWX	CDF = 3.36E-6 (E2 - Div 2 ECCS)			X			X	X	X			X	X		II	M2
35	255SW	South reactor building El 289	1E-2(4)	II	RWX	CDF = 3.35E-6			X					X			X	X			DW
35	262SW	South reactor building El 306	1E-2(4)	II	RWX	CDF<1E-7			X				2 of 3					X			M2
35	272SW	South reactor building El 328 SW	1E-2(4)	N	RWX	CDF<1E-7			X												
35	274SW	South reactor building El 328 SE	1E-2(4)	II	no	no initiator or impact on PRA															
38	311NZ	Computer battery room	5.1E-04	N	no	no initiator or impact on PRA															
39	307NZ	Div 1 West battery room	5.0E-04	N	no	no initiator or impact on PRA															
40	308NZ	Div 2 East battery room	5.0E-04	N	no	no initiator or impact on PRA															
42	708NW	Oil storage tank	3.8E-03	N	yes	CDF <1E-7						1F	2 of 3								
48	236NZ	Div 1 HVAC room	2.4E-03	I	no	no initiator or impact on PRA															
49	701NW	RR track bay	5.3E-04	N	no	no initiator or impact on PRA															
49	CHWTR	Chilled water STR	6.0E-03	N	no	no initiator or impact on PRA															
50	256NZ	Main steam tunnel	6.2E-04	I	yes	CDF <1E-7		DG				X	X								
50	702NZ	Turbine building	3.6E-02	N	yes	CDF <1E-7															
50	703NZ	Turbine building	8.3E-04	N	yes	CDF <1E-7						X									
50	704NZ	Turbine building	8.7E-04	N	yes	CDF <1E-7							1 of 3								
50	705NZ	Turbine building	8.7E-04	N	yes	CDF <1E-7							1 of 3								
50	706NZ	Turbine building	8.7E-04	N	yes	CDF <1E-7							1 of 3								
50	707SW	Turbine building	5.9E-04	N	yes	CDF <1E-7					1C	X									
50	709NZ	Turbine building	5.0E-03	N	yes	CDF <1E-7					X	X	X								
50	716SW	Turbine building (717, 718SW)	1.3E-02	N	yes	CDF <1E-7				X	X	X	X								
50	721NZ	Turbine building	5.9E-04	N	yes	CDF <1E-7						X									
50	722NZ	Turbine building	7.9E-04	N	yes	CDF <1E-7															
50	723NZ	Turbine building	6.8E-04	N	yes	CDF <1E-7							1 of 3								
50	724NZ	Turbine building	6.8E-04	N	yes	CDF <1E-7							1 of 3								
50	725NZ	Turbine building	6.8E-04	N	yes	CDF <1E-7							1 of 3								

Table A2-1A: Initial Fire Area Screening Analysis Summary, CDF – 5/2010 Post IPEEE Update

Area	Zone	Description	Fire Freq	App R	Initiator	Screening Summary	System Impacts														
							OG	A1/2	RW	TW	AS	CN	FW	HS	IC	LA	LB	LC	LS	SV	CV
50	727SW	Turbine building (730, 731SW)	7.0E-03	N	yes	CDF <1E-7					1A,1C	X	X								
50	728NZ	Turbine building	5.3E-04	N	yes	CDF <1E-7							X								
50	729NZ	Turbine building	5.3E-04	N	yes	CDF <1E-7															
50	751NZ	Turbine building	2.1E-03	N	yes	CDF <1E-7															
50	752.1NZ	Turbine building	1.1E-03	N	yes	CDF <1E-7						X									
50	752.2NZ	Turbine building	1.5E-03	N	yes	CDF <1E-7						X									
50	753NZ	Turbine building	2.1E-03	N	yes	CDF <1E-7															
50	754NZ	Turbine building	5.8E-04	N	yes	CDF <1E-7															
50	755NZ	Turbine building	1.5E-02	N	yes	CDF <1E-7															
50	756NZ	Turbine building	5.8E-04	N	yes	CDF <1E-7															
50	762NZ	Turbine building	5.3E-04	N	yes	CDF <1E-7															
50	763NZ	Turbine building	2.1E-03	N	yes	CDF <1E-7															
50	764NZ	Turbine building	5.3E-04	N	yes	CDF <1E-7															
51	601XL	West normal switchgear	9.7E-04	N	LOSP	CDF <1E-7	OG		X	X	X	X	X								
52	602XL	East normal switchgear	1.1E-03	N	LOSP	CDF <1E-7	OG		X	X	X	X	X								
52	604NZ	East normal switchgear	9.6E-04	N	KBX	CDF <1E-7	KBR		X	X	X		1 of 3								
53	603NZ	Battery rooms	4.9E-04	N	LOSP	CDF <1E-7	OG			X	1A,1B	X	X								
55	237NZ	Div 2 HVAC room	2.4E-03	II	RWX	CDF <1E-7			X	X											
55	361NZ	Pipe tunnels	2.3E-04	II	RWX	CDF <1E-7			2 of 3	X		3 of 6	2 of 3								
55	362.1NZ	Pipe tunnels (FA16 362.2NZ)	2.3E-04	II	RWX	CDF <1E-7			2 of 3	X		3 of 6	2 of 3								
55	363NZ	Pipe tunnels El 244	2.3E-04	II	TWX	CDF <1E-7				X											
55	811NZ	Service water intake/disch area	2.3E-04	N	no	no initiator or impact on PRA															
55	902NW	Condensate storage tanks	2.7E-03	N	LOC	CDF <1E-7						X									
57	961NW	Asphalt tank and pumps	.7.4E-04	N	no	no initiator or impact on PRA															
58	901NZ	LWS - Radwaste	7.5E-04	N	no	no initiator or impact on PRAi															
58	904NZ	LWS - Radwaste	7.4E-04	N	no	no initiator or impact on PRA															
58	906NZ	LWS - Radwaste	7.7E-04	N	no	no initiator or impact on PRA															
58	911NW	LWS - Radwaste	7.9E-04	N	no	no initiator or impact on PRA															
58	941NW	LWS - Radwaste	7.6E-04	N	no	no initiator or impact on PRA															
59	908NZ	WSS - Radwaste	7.4E-04	N	no	no initiator or impact on PRA															
59	921SW	WSS - Radwaste	7.5E-04	N	no	no initiator or impact on PRA															
59	951NW	WSS - Radwaste	7.5E-04	N	no	no initiator or impact on PRA															
60	807NZ	Service water pump B	6.0E-03	II	SAX	CDF <1E-7 (SB)						3 of 6									
60	808NZ	Auxiliary boiler room	3.0E-03	N	no	no initiator or impact on PRA															
61	806NZ	Service water pump A	6.0E-03	I	SAX	CDF <1E-7 (SA)						3 of 6									
62	804NW	Diesel fire pump room	6.6E-03	N	no	no initiator or impact except fire pump															
63	805NZ	Electric fire pump room	6.7E-03	N	no	no initiator or impact except fire pump															
64	715NZ	Foam pump room	5.8E-03	N	no	no initiator or impact on PRA															
65	714NW	I&C shop	5.3E-04	N	no	no initiator or impact on PRA															
66	402.2SW	Div 1 diesel day tank	2.3E-04	I	no	DG unavailability insignificant		DG													
67	403.2SW	Div 2 diesel day tank	2.3E-04	II	no	DG unavailability insignificant		DG													
68	404.2SW	HPCS diesel day tank	2.3E-04	III	no	DG unavailability insignificant								DG							
69	801NZ	Water treatment building	6.2E-03	N	no	no initiator or impact on PRA															
70	395XL	Radwaste switchgear room	9.8E-04	N	LOF	CDF <1E-7					1C	X	X								
70	903NZ	Decon area & RW CR	7.8E-04	N	no	no initiator or impact on PRA															
70	905NW	Decon area & RW CR	7.6E-04	N	no	no initiator or impact on PRA															
70	907NZ	Decon area & RW CR	7.5E-04	N	no	no initiator or impact on PRA															
71	803,802NZ	Intake area/Screenwell Bldg	6.6E-03	II	LOC	CDF <1E-7						X									
72	351.1NZ	Instrument shop El 288 CB	5.3E-04	I & III	A1X	CDF=2.71E-7 based on 380.1		A1		X				X							
72	351.2NZ	Corridor El 288 CB	5.3E-04	I & III	A1X	CDF=2.71E-7 based on 380.1		A1		X				X							
73	247NZ	Standby gas treatment-A	2.4E-03	N	no	no initiator or significant impact															X
74	248NZ	Standby gas treatment-B	2.4E-03	N	no	no initiator or significant impact															X

Table A2-1A: Initial Fire Area Screening Analysis Summary, CDF – 5/2010 Post IPEEE Update

Area	Zone	Description	Fire Freq	App R	Initiator	Screening Summary	System Impacts														
							OG	A1/2	RW	TW	AS	CN	FW	HS	IC	LA	LB	LC	LS	SV	CV
75	339NZ	HPCS battery room	5.0E-04	III	no	HPCS unavailability insignificant								X							
76	380.1NZ	Operators lunch room El 306	2.3E-03	I & III	A1X	CDF=1.18E-6		A1						X							
76	380.2NZ	Corridor/toilet El 306	5.3E-04	I & III	A1X	CDF=2.71E-7 based on 380.1		A1						X							
77	621NZ	Penthouse	3.8E-03	N	LOC	CDF <1E-7															
78	612XL	West normal switchgear	9.8E-04	N	LOSP	CDF <1E-7	OG		2 of 3	X	X	X	X								
79	613XL	East normal switchgear	9.7E-04	N	LOSP	CDF <1E-7	OG		X	X	1A,1B	X	X								
80	246NW	South Aux service building	5.9E-04	N	RWX	CDF <1E-7			X												
80	611NW	Electrical bay	1.5E-04	N	RWX	CDF <1E-7			X	X	X	X	X								
80	761.2NZ	Clean access area El 288	5.9E-04	N	RWX	CDF <1E-7			2 of 3			X	1 of 3								
80	761.3NZ	Clean access area El 306	5.9E-04	N	RWX	CDF <1E-7			2 of 3			X	2 of 3								
81	253XL	600V switchgear room	9.6E-04	N	RWX	CDF <1E-7			X				2 of 3								
82	732NW	Lube oil storage room	4.0E-03	N	yes	CDF <1E-7							1 of 3								
83	726XL	Normal switchgear East	9.8E-04	N	yes	CDF <1E-7					1C	X	X								
84	740XL	Normal switchgear West	9.8E-04	N	yes	CDF <1E-7					1C	2 OF 6	X								
85	251NW	Standby gas treatment-HVAC	3.7E-03	N	no	no initiator or impact on PRA															
86	274SW	Resin storage area	2.3E-03	N	no	no initiator or impact on PRA															
86	770NW	Cafeteria and corridor	5.3E-04	N	no	no initiator or impact on PRA															
87	255SW	Div 1 SFC pump room (or 87SW)	3.5E-03	I	no	no initiator or impact on PRA															
88	331NW	Corridor El 261 CB	7.7E-04	I & III	LOSP	5.10E-6	OG	A1	X	X	X	X	X	X							
90	761.1NZ	Stairway enclosure	5.3E-04	N	RWX	CDF <1E-7			2 of 3												

Table 2A-1A Notes:

1. N2-EOP-SC, Rev 10 requires the operator to immediately shut down the plant per OP-101C & D if more than 1 RB area temperature exceeds 135F. This is assumed to occur in the North and South Auxiliary Bays.

2. The primary containment was qualitatively screened out. With the exception of instrumentation and containment venting valves, most equipment required to respond to an initiator in the drywell are located outside the primary containment. There is separation among the instrumentation and venting valves, and the primary containment is normally inerted during operation.

3. The following summarizes the column headings (PRA systems) and the codes used to summarize impacts:

OG - Offsite AC power in the PRA is represented by four event tree top events. OG represents the offsite grid (OG failure equates to a total loss of all offsite power), KA represents 115kV source A, KB represents 115kV source B, and KR represents crosstie capabilities between KA and KB to plant loads. The following explains the impact codes used in the table:

KAR - failure of both KA and KR capabilities
KBR - failure of both KB and KR capabilities
OG - failure of all offsite AC power (KA, KB & KR failed)

A1/2 - Division 1 and 2 emergency AC power was modeled as top events A1 and A2 in the PRA. For those systems where simplified cable block diagrams were developed or detailed evaluation of cables was performed, the evaluations of each component considered cables up to the emergency and normal switchgear rooms and control complex. However, in some cases where Appendix R indicated that emergency AC was in the fire zone or if the area was not evaluated in detail, it may have been assumed. The following explains the impact codes used in the table:

DG - only the emergency diesel for the applicable Division is affected.
A1 - Div 1 emergency AC failure occurs or is assumed.
A2 - Div 2 emergency AC failure occurs or is assumed.
X - failure of both divisions can occur or is assumed.

RW - Reactor building closed loop cooling (RBCLC) is modeled in the PRA as top event RW. The impacts are based on evaluation of the critical cables required for RBCLC components. The following explains the impact codes used in the table:

1 of 3 - one of three pump trains are impacted
2 of 3 - two of three pump trains are impacted
X - system failure occurs

TW - Turbine building closed loop cooling (TBCLC) is modeled in the PRA as top event TW. The impacts are based on evaluation of the critical cables required for TBCLC components. The following explains the impact codes used in the table:

1 of 3 - one of three pump trains are impacted
2 of 3 - two of three pump trains are impacted
X - system failure occurs

AS - Instrument air is modeled in the PRA as top event AS. The impacts are based on evaluation of the critical cables required for instrument air components. The following explains the impact codes used in the table:

1A - compressor 1A is impacted
1B - compressor 1B is impacted
1C - compressor 1C is impacted
X - system failure occurs

CN - The main condenser is modeled in the PRA as top event CN. The impacts are based on evaluation of the critical cables required for main condenser and support system components. The following explains the impact codes used in the table:

1 of 6 - one of six circ water pumps are impacted
2 of 6 - two of six circ water pumps are impacted
3 of 6 - three of six circ water pumps are impacted
X - system failure due to more than 3 circ water pumps impacted and/or MSIVs close and/or main condenser or its support systems fail

FW - The main feedwater system is modeled in the PRA as top event FW. The impacts are based on evaluation of the critical cables required for feedwater and condensate components. The following explains the impact codes used in the table:

1 of 3 - one of three pump trains are impacted
2 of 3 - two of three pump trains are impacted
X - system failure occurs

HS, IC, LA, LB, LC, and LS model HPCS, RCIC, RHR “A”, RHR “B”, and LPCS, respectively in the PRA. The impact is either system failure, “X”, or no impact. The impacts were developed from Appendix R evaluations and/or evaluations of cables in a specific fire zone.

SV - Safety relief valves opening to allow low pressure injection is modeled in the PRA as top event SV. In general, the cables for this system were not evaluated in detail, because Appendix R assured that at least one Div of ADS is available. With one Div available, the unavailability of SV is low and in combination with the fire frequency is not significant. Still, if failure of A1 or A2 is assumed in Appendix R Div 1 or Div 2 areas that were not evaluated in detail, this results in loss of 1/2 of SV in the PRA. Thus, the impact is included where A1 and A2 are failed. In cases where SV impact was found, “I” or “II” is shown as an impact to represent Div 1 and 2, respectively.

CV - Containment venting is modeled in the PRA as top event CV. The impacts are based on evaluation of the critical cables required for containment venting components. The following explains the impact codes used in the table:

M1 - Div 1 MOVs in the standby gas treatment system (SGTS) are impacted. This has an insignificant impact on containment venting capability since Div 2 MOVs are available and the Div 1 MOVs can be locally opened or closed.
M2 - Div 2 MOVs in the SGTS system are impacted. This has an insignificant impact on containment venting capability since Div 1 MOVs are available and the Div 2 MOVs can be locally opened or closed.

DW - Drywell venting is impacted. This has an insignificant impact on containment venting since the preferred path from the suppression chamber is available.
Air - The outside air operated valves and/or the 20" AOV101 must be locally opened. There may be other impacts such as M1 or M2 and/or drywell venting may fail, however, suppression chamber venting is available if the outside AOV is opened locally as modeled in the PRA.
X - system failure

Div 1 and 2 DC power (D1 and D2), vital AC (UA and UB), ECCS actuation (E1 and E2), and service water (SA and SB) were treated similarly to SV. Loss of service water or DC at the main source was modeled as an initiating event as shown in the table. Where cable evaluations were performed on main line systems or the BOP systems, cable evaluations and impacts were conducted to the electrical power source and controls.

(4) Reactor building fire zones were evaluated with a screening frequency of 1E-2/yr.

Table A2-1B: Initial Fire Area Screening Analysis Summary, LERF

Flags	CLERP	FREQ	LERF	LERF Screen?	CDF Screen?
26\373.1NZ_RPS	4.29E-03	9.90E-03	4.24E-05	No	No
26\373.XNZ_A1X	4.29E-03	9.90E-03	4.24E-05	No	No
26\373.1NZ_SCRAM	4.28E-03	9.90E-03	4.24E-05	No	No
26\373.2NZ_RPS	4.29E-03	2.30E-04	9.86E-07	No	No
24\356NZ_A2X	4.29E-03	2.30E-04	9.86E-07	No	No
24\356NZ_A1X	4.29E-03	2.30E-04	9.86E-07	No	No
24\356NZ_RPS	4.29E-03	2.30E-04	9.86E-07	No	No
26\373.3NZ_RPS	4.29E-03	2.30E-04	9.86E-07	No	No
26\373.XNZ_A2X	4.29E-03	2.30E-04	9.86E-07	No	No
24\356NZ_SCRAM	4.28E-03	2.30E-04	9.85E-07	No	No
26\373.3NZ_SCRAM	4.28E-03	2.30E-04	9.85E-07	No	No
26\373.2NZ_SCRAM	4.28E-03	2.30E-04	9.85E-07	No	No
24\357XL_A1X	4.29E-03	1.50E-04	6.43E-07	No	No
24\357XL_RPS	4.29E-03	1.50E-04	6.43E-07	No	No
24\357XL_A2X	4.29E-03	1.50E-04	6.43E-07	No	No
24\357XL_SCRAM	4.28E-03	1.50E-04	6.42E-07	No	No
88\331NW_LOSP	6.82E-04	7.70E-04	5.25E-07	No	No
16\352NW_LOSP	4.27E-04	1.60E-04	6.84E-08	No	No
16\332NW_LOSP	4.27E-04	1.50E-04	6.41E-08	No	No
16\371NW_LOSP	4.27E-04	1.50E-04	6.41E-08	No	No
35\238SW_RWX	6.29E-06	1.00E-02	6.29E-08	No	No
35\245SW_RWX	6.29E-06	1.00E-02	6.29E-08	No	No
35\223SW_RWX	6.29E-06	1.00E-02	6.29E-08	No	No
35\255SW_RWX	6.23E-06	1.00E-02	6.23E-08	No	No
35\213SW_RWX	6.23E-06	1.00E-02	6.23E-08	No	No
76\380.1NZ_A1X	1.74E-05	2.30E-03	4.01E-08	No	No
19\336XL_A2X	1.67E-05	9.70E-04	1.62E-08	No	No
34\232SW_RWX	1.24E-06	1.00E-02	1.24E-08	No	No
72\351.1NZ_A1X	1.74E-05	5.30E-04	9.23E-09	Yes	No

Screening Criteria: < 1E-8

Table A2-2: Detailed Evaluation Summary and Initiating Events Modeled –IPEEE and Updated

Area	Zone	Description	Screening Summary 2010 Criteria ≥ 1E-7	Screening Summary IPEEE Criteria ≥ 1E-6	Detailed Evaluation	Model Initiating Event
16	332NW	Div 1 cable chase West	CDF = 6.92E-7	CDF = 1E-5	Detailed evaluation	FA16A FA16B
16	352NW	Div 1 cable chase West	CDF = 7.38E-7	CDF = 1.1E-5		
16	371NW	Div 1 cable chase West	CDF = 6.92E-7	CDF = 1E-5		
17	333XL	Div 1 standby switchgear room	CDF = 1.22E-7	CDF = 2E-6	Detailed evaluation	F333XL
17	343NZ	Remote shutdown room A West	CDF < 1E-7	CDF = 3E-7	Detailed evaluation [evaluated due to room B not screened]	F343NZ
18	304NW	230 degree tunnel	CDF = 1.58E-7	CDF = 3E-6	Detailed evaluation	FA18A FA18B
18	324NW	Div 2 riser area	CDF = 1.58E-7	CDF = 3E-6		
18	337NW	Div 2/3 cable chase East	CDF = 1.58E-7	CDF = 3E-6		
18	359NW	Div 2/3 cable chase East	CDF = 1.58E-7	CDF = 3E-6		
18	377NW	Div 2/3 cable chase East	CDF = 1.58E-7	CDF = 3E-6		
19	323NW	Div 2 cable routing area	CDF = 1.58E-7	CDF = 3E-6		
19	336XL	Div 2 standby switchgear room	CDF = 5.03E-7	CDF = 1.9E-5	Detailed evaluation	F336XL
19	338NZ	Remote shutdown room B East	CDF < 1E-7	CDF = 3E-6	Detailed evaluation	F338NZ
24	356NZ	PGCC relay (353,354,362SG)	CDF = 2.63E-5	CDF = 2.3E-4	Screened based on evaluation at panel level of detail.	None
24	357XL	PGCC computer room (358XG)	CDF = 1.71E-5	CDF = 1.5E-4	Screened after more careful assessment of impacts	None
26	373.1NZ	Control Room (372-376)	CDF = 1.13E-3	CDF = 9.9E-3	Fires in panels 852 (FCR1 and FCR2) and 601 (FCR3) determined important. FCR0 conservatively added to represent other panels.	FCR0 FCR1 FCR2 FCR3
26	373.2NZ	Shift supervisors office	CDF = 2.4 E-5	CDF = 2.3E-4	Screened after more careful assessment of impacts	None
26	373.3NZ	Training room	CDF =2 .4 E-5	CDF = 2.3E-4	Screened after more careful assessment of impacts	None
34	212SW	North reactor building El 175	CDF = 1.58E-7	CDF = 8E-6	Screened based on detailed evaluation	None
34	222SW	North reactor building El 215	CDF = 1.58E-7	CDF = 8E-6	Screened based on detailed evaluation	None
34	232SW	North reactor building El 240	CDF = 2.48E-7	CDF = 8E-6	Screened based on detailed evaluation	None
34	243SW	North reactor building El 261	CDF = 1.58E-7	CDF = 8E-6	Screened based on detailed evaluation	None
34	252SW	North reactor building El 289	CDF = 1.58E-7	CDF = 8E-6	Screened based on detailed evaluation	None
35	213SW	South reactor building El 175	CDF = 3.35E-6	CDF = 8E-6	Screened based on detailed evaluation	None
35	223SW	South reactor building El 215	CDF = 8.43E-6	CDF = 8E-6	Screened based on detailed evaluation	None
35	238SW	South reactor building El 240	CDF = 3.35E-6	CDF = 8E-6	Screened based on detailed evaluation	None
35	245SW	South reactor building El 261	CDF = 3.36E-6	CDF = 8E-6	Screened based on detailed evaluation	None
35	255SW	South reactor building El 289	CDF = 3.35E-6	CDF = 8E-6	Screened based on detailed evaluation	None
51	601XL	West normal switchgear	CDF < 1E-7	CDF = 1.1E-6	Total loss of offsite power modeled after evaluation	FNSGR
52	602XL	East normal switchgear	CDF < 1E-7	CDF = 1.3E-6		

Table A2-2: Detailed Evaluation Summary and Initiating Events Modeled –IPEEE and Updated

Area	Zone	Description	Screening Summary 2010 Criteria ≥ 1E-7	Screening Summary IPEEE Criteria ≥ 1E-6	Detailed Evaluation	Model Initiating Event
60	807NZ	Service water pump B	CDF < 1E-7	CDF = 3.2E-6	Screened based on detailed evaluation	None
61	806NZ	Service water pump A	CDF < 1E-7	CDF = 3.2E-6	Screened based on detailed evaluation	None
72	351.1NZ	Instrument shop El 288 CB	CDF = 2.71E-7 based on 380.1	CDF = 5.8E-7 based on 380.1	Screened based on detailed evaluation	None
72	351.2NZ	Corridor El 288 CB	CDF = 2.71E-7 based on 380.1	CDF = 5.8E-7 based on 380.1	Screened based on detailed evaluation	None
76	380.1NZ	Operators lunch room El 306	CDF = 1.18E-6	CDF = 2.5E-6	Screened based on detailed evaluation	None
76	380.2NZ	Corridor/toilet El 306	CDF = 2.71E-7 based on 380.1	CDF = 5.8E-7 based on 380.1	Screened based on detailed evaluation	None
78	612XL	West normal switchgear	CDF < 1E-7	CDF = 1.2E-6	Total loss of offsite power modeled after evaluation	FNSGR
79	613XL	East normal switchgear	CDF < 1E-7	CDF = 1.1E-6		
88	331NW	Corridor El 261 CB	5.10E-6	5.30E-05	Detailed evaluation	FA88B

Table A2-3: Fire Initiating Events and Their Contribution to CDF and LERF

Initiator	Frequency	Location	Impacts	CDF and LERF Contribution, Percent					
				CDF Base	CDF1 Div.1 DG OOS	CDF2 Div.2 DG OOS	LERF Base	LERF1 Div.1 DG OOS	LERF2 Div.2 DG OOS
FCR0	1.9E-4	Control Room	Feedwater and main condenser	12.4%	4.6%	3.50%	1.3%	0.6%	0.5%
FCR1	1.0E-5	Control Room Panel 852	Same as FCR0, LOSP, HPCS, potential Div 2 DG	2.7%	3.8%	2.49%	2.3%	17.1%	9.7%
FCR2	1.0E-5	Control Room Panel 852	Same as FCR0, LOSP A, potential Div 1 DG	3.7%	2.0%	1.02%	0.4%	0.4%	0.2%
FCR3	1.0E-5	Control Room Panel 601	Service Water	3.2%	1.2%	0.92%	0.3%	0.2%	0.1%
FNSGR	1.8E-4	Normal SWGR	LOSP	0.6%	2.5%	2.64%	2.6%	1.2%	1.2%
FA88B	3.6E-6	Control Bldg Corridor EL 261	LOSP, HPCS	0.6%	1.5%	1.51%	3.2%	1.3%	1.3%
FA16B	2.1E-6	Div 1 Cable Chase West w/ Auto Suppression Failure	LOSP, Division 1 AC, RCIC	0.27%	0.1%	4.35%	1.8%	0.1%	4.2%
FA18B	2.1E-6	Div 2 Cable Chases w/ Auto Suppression Failure	LOSP, Division 2 AC, HPCS	1.16%	10.2%	0.09%	7.0%	9.3%	0.1%
FA16A	4.1E-5	Div 1 Cable Chase West	Division 1 AC and RCIC	0.08%	0.0%	0.18%	0.1%	0.0%	0.2%
FA18A	4.1E-5	Div 2 Cable Chases	Division 2 AC and HPCS	2.11%	0.6%	0.41%	0.2%	0.2%	0.1%
F333XL	6.2E-5	Div 1 Switchgear Room	Division 1 AC	0.08%	0.0%	0.03%	0.0%	0.0%	0.0%
F336XL	6.2E-5	Div 2 Switchgear Room	Division 2 AC	1.03%	0.3%	0.18%	0.0%	0.0%	0.0%
F338NZ	1.4E-4	Remote Shutdown Room B	RCIC and RHR B	0.00%	0.0%	0.01%	0.0%	0.0%	0.0%
F343NZ	1.4E-4	Remote Shutdown Room A	RCIC and RHR A	0.02%	0.0%	0.20%	0.0%	0.0%	0.0%
			TOTAL	30%	27%	18%	19%	30%	18%

ATTACHMENT A2-A

IGNITION FREQUENCY COMPARISON

Ignition frequencies are as derived from Table 1.2 of FIVE Attachment 10.3 (EPRI TR 100370) and have not been updated to recent data. The following summarizes a comparison with recent updated data in EPRI 1016735 for some key ignition sources in the NMP2 PRA:

Electrical Cabinets – Table 1.2 of FIVE Attachment 10.3 (EPRI TR 100370) has the following generic values:

Control Room = 9.5E-3
Switchgear Room = 1.5E-2
Cable Spreading = 3.2E-3

More recent data from EPRI 1016735 Bin 15.1 (non-HEAF) = 2.4E-2 and Bin 15.2 (HEAF) = 1.1E-3. Also, there is a separate Bin 4 = 8.2E-4 for the main front control board in the control room. Because of differences in methodology such as counting cabinets, etc., it is difficult to compare without essentially updating the ignition frequencies for the NMP2 fire PRA. However, the present frequencies are judged to be reasonable based on the following comparisons:

- The Unit 2 IPEEE frequency per cabinet in the emergency switchgear rooms is ~5E-5/yr.
- The value using the latest Bin 15.1 frequency and assuming 800 cabinets (unit 1 value, but Unit 2 is expected to have more cabinets) would be approximately 3E-5/yr.
- Using NRC Inspection Manual 0609, Appendix F, Attachment 4, the frequency per cabinet is 5.5E-5/yr.

Transients – Table 1.2 of FIVE Attachment 10.3 (EPRI TR 100370) has a value of 1.3E-3 whereas more recent data from EPRI 1016735 Bin 7 = 4.8E-3. Thus, there could be an overall increase in transient frequency, but for the critical areas identified in the NMP2 fire PRA it is expected that the frequency will be comparable with no significant change once the frequency is adjusted for these compartments (e.g., influence factors and controls as described in Section 6 of NRREG/CR-6850).

Main Control Board – The frequency of a fire with major impacts was developed for the NMP2 PRA based on an evaluation of data for control room fires and the number of cabinets; a frequency of 1.1E-5/cabinet in the control room was used. This frequency would be closer to 1E-6 based on more recent data and methods:

- Total frequency for main control board = 8.2E-4 (EPRI 1016735 Bin 4)
- There are 5 cabinets that make up the main control board
- The conditional probability from NUREG/CR-6850 Appendix L that the fire spreads beyond the initial starting point (e.g., a switch) and causes additional impacts can be considered. This is reasonable because the presence of operators essentially ensures incipient detection and suppression before the fire can develop and spread.

ATTACHMENT A2-B

DETAILED EVALUATIONS

Control Room Evaluation (FA26 373.1NZ) - As a result of detailed analysis, the following four fire initiators are included in the PRA model.

FCR0 - Fire in control room with minor impact = 2.1E-4/yr
FCR1 - Fire in control room panel 852 - LOSP & HPCS failure = 1.1E-5/yr
FCR2 - Fire in control room panel 852 - partial LOSP = 1.1E-5/yr
FCR3 - Fire in control room panel 601- loss of SW, but recoverable = 1.1E-5/yr

The most difficult area to screen was the control room because all safety and non-safety system control cables enter this area. In order to realistically estimate core damage frequency (CDF) for fires in this area, the routing of cables through the area was evaluated as well as the impact of fires in specific electrical cabinets. It was determined that 2 main control room cabinets dominate risk with regard to impact on the PRA. In addition, the fire events that have occurred in the database were evaluated to develop a more realistic estimate of a fire initiator that causes major damage.

GAP: Completeness of main control board fire scenario development is lacking, but scenarios are included for Panel 852, which is most important for the EDG AOT evaluation because this panel includes offsite power controls as well as controls for all 3 emergency diesels.

Shift Supervisors Office (FA26 373.2NZ), Training Room (FA26 373.3NZ), and PGCC Computer Room (FA24 357XL) - These compartments were not evaluated during the initial screening analysis (CDF was set equal to the total fire frequency for the area) because the spatial database developed for fire areas 24 and 26 did not distinguish between zones 373.1NZ (control room), 373.2NZ (shift supervisors office) and 373.3NZ (training room). Likewise the database did not distinguish between the relay and computer rooms. Thus, the actual cables being routed in these zones have to be evaluated. There is no safety related or important non-safety related equipment or cables in the supervisor's office or the training room based on a review of electrical drawings and a visual inspection. These rooms are screened out. Regarding the computer room, the design review indicates that no safety related (divisional) cables are located in this zone. It is considered possible that a fire could cause a plant trip, but the low frequency of a fire in this zone in combination with the minor impact on plant systems indicates that this zone can be screened out.

Operators Lunch Room El 306 (FA76 380.1NZ) - This fire zone was not evaluated during the initial screening analysis. The initial screening analysis assumed loss of Division 1 AC power and HPCS based on Appendix R results and because the spatial database developed for fire area 76 did not distinguish between zones 380.1NZ (operators lunch room) and 380.2NZ (corridor). Thus, the actual cables being routed in these zones have to be evaluated. There are smoke detectors in the area with no automatic suppression. However, there are operators and other personnel either in the area or close by.

During a walkdown, the following conduits were observed on one wall in the room:

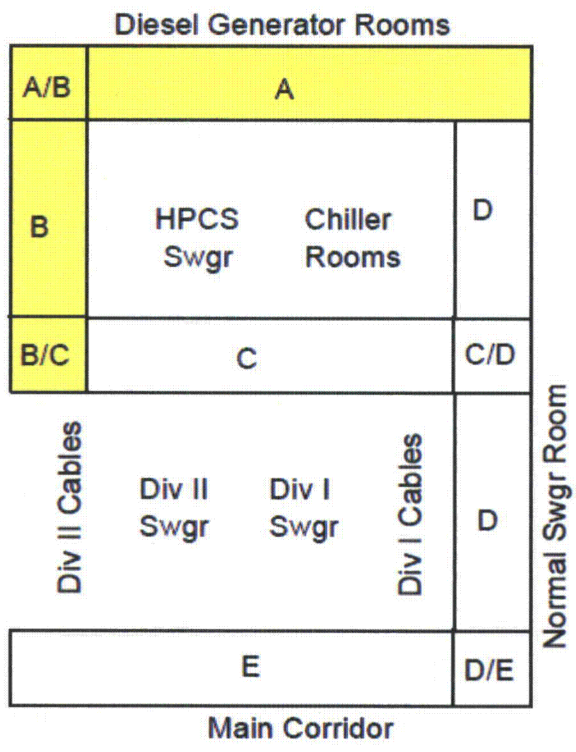
- 2CC502PF1 (purple), 2CC502PF2 (purple), 2CC502PF4 (purple), 2CC502PF5 (purple)
- 2CC520YP (yellow) containing cable 2HVKBYC503

The purple cables are associated with the HPCS (Div 3) system and the yellow cable is associated with Div 2 chilled water (control building cooling). Even if failure of these cables is assumed, the impact would be insignificant; this location can be screened out at <1E-7/yr.

There are smoke detectors in this area with no automatic suppression.

Corridor El 261 CB (FA88 331NW) - The initiating event frequency for FA88B contains the probability that automatic suppression fails (7.7E-4/yr for frequency of fire in FA88 times 0.05 probability of suppression failure = 3.9E-5/yr) which causes loss of normal AC power and HPCS. Successful suppression is assumed to have no impact on these plant systems.

This corridor is very long as shown in the simplified diagram. This diagram shows several sections that were defined for the purposes of documenting walkdown notes. For initial analysis purposes, the corridor was broken into two separate zones with the shaded portion called FA88A and the remaining corridor FA88B. These two zones were identified because FA88A (Sections A and B, including B/C) in the diagram has no automatic suppression (does have smoke detection) and the ceilings are much lower. Whereas FA88B, the remaining non shaded sections, have automatic detection and suppression (smoke detection and cable tray water spray) and the ceiling is much higher. Thus, the following strategy was developed to more realistically assess the risk of fires in fire area 88:



FA88A was evaluated to determine the impact of a fire in this zone. Initially, it will be assumed that a fire will cause this impact without a chance for suppression. All non-safety trays and conduits were found to have no impact on offsite power and the balance of plant (feedwater and main condenser). A single conduit (2CL511GD containing cable 2BYSAGL609) can impact the Division 1 diesel generator. Another conduit, 2CL510YF, was found to be empty (no cable). Apparently the control cable to the Division 2 diesel generator was rerouted through 2CL510YH in another fire area as described in the FA88A evaluation below. Also, there is a HPCS (purple cable) in the B/C interface area.

FA88B has automatic suppression. If suppression is successful, no impacts are assumed to occur in cable trays and conduits. This is based on an evaluation of the time to cable critical temperature versus time to detect and suppress the fire. Also, all the impacts are associated with cables in cable trays and conduits up high in the vicinity of cable tray water sprays. There are no cables or cabinets of concern near the floor area. If automatic suppression fails, initially it will be assumed that all impacts identified in the

FA88B occur. This includes loss of offsite power, balance of plant systems, and HPCS. The location of the Division 1 diesel cable in FA88A which has no automatic suppression is at the opposite end of section A from where FA88B starts. Thus, a fire that impacts this cable and causes loss of offsite power in FA88B is considered unlikely and is neglected. FA88A can be easily screened out because the only impact of a fire is the Division 1 diesel and possibly HPCS. Even if we assume an initiating event and loss of the diesel and HPCS, the scenario will easily screen out below 1E-7/yr.

FA88B can be conservatively evaluated by running the FA88 fire initiator through the PRA with HPCS and offsite power failed. This is conservative because the total frequency of a fire in FA88 has been applied to the FA88B portion and additional detailed evaluations of HPCS cables and their vicinity to offsite power and other balance of plant cables has not been considered.

Fire area FA88A was inspected to determine if Div 1, 2 & 3 diesel generators are lost. The specific goal was to identify which wires were impacted by the fire and did they actually cause the loss of diesel generators. There are 2 conduits 2CL510YF & 2CL511GD in this zone. A query of the CRS2 database for conduit 2CL511GD and a review of drawings EE-10A-9 indicates that cable 2BYSAGL609 provides power to 2BYS*PNL204A in the diesel generator room. Loss of this cable causes loss of the Div 1 DG control circuits for both the engine and the generator. A query of the CRS2 database for conduit 2CL510YF indicated that this conduit is routed from 2BYS*PNL204B to the tray system located in a different fire area. But, there is not any cable in the conduit. To verify that the power feed to 2BYS*PNL204B was not in this conduit, CRS2 was queried to identify the drawing for this panel. Drawing EE-10A-9 indicates that the power feed to 2BYS*PNL204B is cable 2BYSBYL609. This cable is routed to 2BYS*PNL204B via the following raceways: 2CL507YQ, 2TL507Y, 2TL510Y & 2CL510YH.

Conduit 2CL510YH is located in the diesel generator control room. It runs from 2BYS*PNL204B out of the control room via the floor. Therefore, this conduit is not affected by a fire in FA88.

An evaluation of FA88B indicates this section of fire area 88 has automatic detection and suppression. The fire area walkdown identified that the following divisional conduits exit one of the contiguous fire areas and enter FA88B. The cables in the conduits were identified using the CRS2 database. The divisional cables are:

Div 1	2HVCAGK290, 2HVCCGK290, 2RPSAGK502, 2LACAGK200, 2LACAGK201, 2LACAGK202
Div 2	2LACBYK200, 2LACBYK201, 2LACBYK202, 2HVCBYK206

Failure of each cable was evaluated for the impact on shutdown and the failure of cables was evaluated for breaker coordination and potential loss of the busses that power the cables.

The Division 1 lighting system cables, 2LACAGK200, 2LACAGK201, 2LACAGK202 are powered from panel 2LAC*PNL100A. These cables supply power to the lighting system. Loss of the emergency lighting power feed is judged to have a minimal impact on the ability to respond to the fire since the required lights are battery backed. The supply breaker to 2LAC*PNL100A is sized to not trip in the event that all three cables have bolted faults.

Cables 2HVCAGK290 and 2HVCCGK290 are powered from 2EJS*PNL102A. Loss of each cable has an impact on the capability to isolate the control room when a high radiation condition exists. Damper isolation or loss of this isolation feature has no impact on the capability to respond to this fire. The supply breaker to 2EJS*PNL102A is sized and coordinated so as to not open if both of these cables have bolted faults.

Cable 2RPSAGK502 is powered by panel 2RPM*PNLB100. This panel provides power to the "B" scram solenoids. Failure of this panel generates a 1/2 reactor trip. Loss of the individual cable generates 1/2 for group 1 scram solenoids. This failure has no adverse impact on the capacity to respond to this fire.

The Division 2 lighting system cables 2LACBYK200, 2LACBYK201 and 2LACBYK202 are powered from 2LAC*PNL301B. The individual or combined failures of the cable have a minimal impact on the capacity to respond to this fire and are not modeled (see Div 1 evaluation above).

Cable 2HVCBYK206 powers a heater in the control building HVAC system. Failure of this cable has a minimal impact on the capacity to safely shutdown and is not modeled.

Division 2 Standby Switchgear Room (FA19 336XL) - This initiating event frequency for F336XL is 6.7E-5/yr. The dominant scenario was determined to be loss of Div 2 AC power due to switchgear fires that did not credit suppression.

The initial screening analysis assumed that Division 2 AC power failed, as well as RBCLC and HPCS, given a fire in this location. Walkdowns were performed in support of this more realistic evaluation. The ceiling and cables in this room are very high. Cables enter the cabinets from the top as well as from underneath. There are 7 smoke detectors in this fire zone and a manual carbon dioxide total flooding suppression system. A more realistic analysis of fires in this zone was performed by considering the impacts of fires within cabinets (electrical cabinet fires), on cables external to the cabinets (transient type of fires), and cabinet fire impacts on cables.

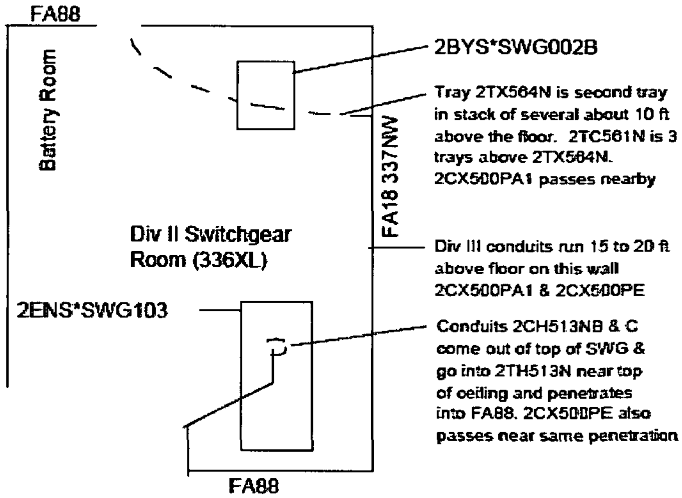
An evaluation of cables concluded that core damage frequency due to fires external to electrical cabinets is less than 1E-7/yr. This is based on the following:

- The frequency of a fire in this zone is dominated by electrical cabinet fires. The contribution from other causes (i.e., welding, transient, ventilation fans, junction box splices) external to the cabinets is much less frequent. This alone provides over an order of magnitude reduction in the screening analysis results.

- The proximity of cables that could have the impact assumed in the initial screening analysis was also evaluated. Based on this evaluation, it was determined that Div 2 cables associated with the 4kV switchgear, the diesel, and its supplies are not in close proximity with normal AC power feeds. Most Div 2 cables come from underneath the switchgear (cable spreading below switchgear room) and normal AC power enters the top of the switchgear cabinets. Three yellow (Div 2) conduits (2CC534YN, G and M) enter the top of the switchgear. They come out of the floor behind the switchgear, go up the wall, and pass over to enter the top of the cabinet passing near 2CH514N. These cables are associated with tie breaker 2NNS-SWG015 103-8 which are control cables for an alternate offsite supply. Thus, fires external to electrical cabinets are unlikely to cause total failure of Div 2 AC power which was assumed in the screening analysis. Cabinet fires will dominate the frequency of a total loss of Div 2 AC power.

- Four critical normal AC power cables to Div 2 switchgear were found in this room during the initial screening analysis. Two are in tray 2TC561N. The other two are in tray 2TH513N and enter this tray from conduits 2CH513NB and 2CH513NC which come from the top of the switchgear cabinet. The frequency of core damage from a fire that causes loss of normal AC power to Div 2 switchgear, but does not lead to loss of the Div 2 diesel, is less than 1E-7/yr (see initial screening analysis of fire area 52 604NZ).

- RBCLC cables were also found in this room during the initial screening analysis. Two cables in tray 2TX564N can lead to a loss of RBCLC which would lead to loss of the main condenser and feedwater systems. However, these cables do not enter any cabinets in the room and the tray is not directly above or next to the Div 2 AC power cabinets. This tray is more than ten feet off the floor (second tray up) and it passes over 2BYS*SWG002B. A fire in this Div 2 DC power cabinet and potential impacts on the above cable trays (i.e., RBCLC) is assessed later in this section. Another tray containing normal AC power (2TC561N) is in the vicinity but higher up near the ceiling. It is judged that fires that could impact these cable would not likely impact Division 2 AC power. Thus, fires that impact Div 2 AC power and RBCLC as assumed in the initial screening analysis are less than 1E-7/yr. Fires that impact RBCLC and not impact Div 2 AC or DC power can be neglected because core damage frequency would be less than 1E-7/yr (RWX CCDP in the PRA times the fire frequency).



- Div 3 HPCS conduits pass along the wall behind the switchgear. The conduits are 2CX500PA1 and 2CX500PE. However, these conduits do not enter any cabinets in the room and it is judged that fires that could impact these conduits would not likely impact Division 2 AC or DC power. One conduit (PA1) passes near normal AC power (tray 2TC561N) and/or RBCLC (tray 2TX564N) at one end of the room. The other conduit (PE) passes near normal AC power (tray 2TH513N) at the opposite end of the room where cables exit through a penetration to FA88. Thus, fires that impact normal AC power to Div 2 switchgear or RBCLC and HPCS is possible in two localized areas. Core damage frequency from these events would be less than 1E-7/yr even without taking credit for suppression.

- It is difficult to impact cables due to transient fires on the floor level because the cables are so high and all cables are IEEE 383 qualified. Even without automatic detection and manual suppression, it appears that the fire could burn out before impacting the cables.

Evaluation of Cabinets - the impact associated with an electrical cabinet fire depends on the cabinet and the location of the fire within the cabinet. Table 4.6-4 of the IPEEE identifies the 20 electrical cabinets in the room and describes the potential impact of a fire within each cabinet. Based on this evaluation, emergency switchgear 2ENS*SWG103 was identified as the most critical cabinet as summarized below:

- Loss of 2VBA*UPS2B results in the loss of Div 2 automatic ECCS actuation, Div 2 RRCS and the ability to open RCIC, LPCI "B" and "C" injection MOVs. Although loss of the UPS was not identified as an automatic plant trip in the PRA, it is assumed for this fire that plant shutdown occurs. The frequency of core damage was conservatively estimated with the PRA to be less than 1E-8/yr, assuming a plant trip and a fire frequency of 1E-3/yr. Thus, this scenario can be neglected.

- Loss of 2BYS*SWG002B (Div 2 DC) results in a plant trip and impacts the availability of several Div 2 components (i.e., pump start and actuation systems). The CCDP in the PRA from loss of Div 2 DC (initiating event D2X) combined with the fire frequency results in CDF less than 1E-7/yr and can be neglected.

- Loss of 2ENS*SWG103 (Div 2 AC) results in a plant trip and impacts the availability of Div 2 systems. The CCDP in the PRA from loss of Div 2 AC (initiating event A2X) combined with the fire frequency results in CDF less than 1E-7/yr and can be neglected.

From the above, loss of Div 2 AC power due to fire is expected to have the most important impact on core damage frequency, although apparently less than 1E-7/yr. For this reason, these scenarios were evaluated in more detail. With regard to a fire in a switchgear cabinet, it will usually start in a specific cubicle and therefore, the impacts suggested in Table 4.6-4 of the IPEEE are not expected for all fires. In order for the total impact to occur, either the fire must occur in a cubicle that could result in the total impact or the fire must occur in a cubicle that has limited impacts, but propagates to cause additional impacts before detection and suppression.

The 4kV switchgear was inspected to determine the fire locations that can cause loss of the bus. A fire in the cubicle where the protective relaying is located can cause the breakers to trip. A fire in a breaker cubicle that faults the upstream (supply side) cables can cause loss of the 4kV bus. A fire in a breaker cubicle that faults the load cables and also causes the breaker to fail as-is can cause loss of the 4kV bus. Alternatively, if the fire causes spurious opening of the breaker or if it causes a fault that is cleared, the fire impact is localized to that load only.

A total loss of power can occur if the protective relaying for the bus is impacted by fire. Total loss of Division 2 4kV is assumed for any fire in the following cubicles:

C3226 Bkr 103-3, C3227 Bkr 103-4, C3236 Bkr 103-14

A total loss of 4kV can occur if a fire in an energized cubicle causes a power system fault within the cubicle and also depowers or fails the breaker control circuit before the CO2 system is manually discharged and suppresses the fire. The fault will be cleared by the upstream breaker, not the branch breaker, resulting in loss of offsite power. After the supply breaker clears, the diesel generator breaker will close onto a faulted bus and quickly open thus preventing recovery of offsite power.

Alternatively, the fire can occur and the branch breaker operates to clear the fault. The CO2 system is manually discharged and suppresses the fire thus limiting any additional damage to the cubicle. A fire in the following cubicles can cause loss of the Division 2 bus or loss of the branch load:

C3228 Bkr 103-5, C3230 Bkr 103-7, no Id Bkr 103-8, C3231 Bkr 103-9, C3232 Bkr 103-10, C3233 Bkr 103-11, C3234 Bkr 103-12, C3239 Bkr 103-N2

A fire in an empty cubicle or racked down/out breaker is not postulated to occur since a fault on the supply side cables is actually a bus fault. The following cubicles have their breaker removed or it's control circuit depowered:

C3225 Bkr 103-2, C3229 no bkr, C3237 Bkr 103-15., C3238 Bkr 103-N1

In summary, there are 3 of 17 cubicles in 2ENS*SWG103, associated with protective relaying, that can lead directly to loss of all Div 2 AC power. There are 8 of 17 cubicles that can lead to loss of all Div 2 AC power if a short (fault) also occurs from the fire. Later in this section, this information is used in developing the conditional frequency of fires that cause a total loss of Div 2 AC power given a fire occurs in 2ENS*SWG103. To develop these conditional frequencies, it was assumed that the total frequency of a fire in the cabinet is dominated by the 11 cubicles that can lead to a total loss of Div 2 AC power. The other six cubicles are usually not energized or empty and judged to contribute less to the total frequency. Thus, conditional frequencies of 3/11 and 8/11 are used in the analysis.

The 600V AC distribution can be failed by a fire in 4kV bus breaker 103-1 switchgear and the feed for 2EJS*US3. Additionally, a fire at the "X3A" transformer will result in loss of 600V AC. Fires at the load center, 2EJS*US3, can cause loss of all 600V AC. 600V AC MCCs 2EHS*MCC303 bus B is separated from the D bus. A fire in the "B" bus can cause loss of the B & D busses while a fire at the D bus will only cause loss of that section.

A fire at the battery board breakers can result loss of 125V DC. It may cause only the loss of the branch load/supply or loss of the bus. Fire at a battery charger will result in loss of one of the two chargers but not the bus. There is another standby charger available that can be switched in after the fire is out and the room ventilated (local operator action).

A fire at the UPS can cause a non recoverable loss of 120V AC.

The fire frequency developed for this fire area using the FIVE methodology included all cabinets. Some cabinets are empty and some switchgear breakers are completely depowered while a few are in standby. Also, fires in several cabinets will have an insignificant impact.

To better model this area, a more detailed evaluation was performed to identify cabinets/cubicles/enclosures that are energized or have been previously shown to be important to risk. The approach taken realized that only powered equipment was likely to fail and only those cubicles that were previously shown to have some affect on risk need be evaluated.

This fire area contains very few exposed cables and they are locates more than 20 feet above the floor. All of the important cables are in cubicles or cabinets. There is no Div 2 4kV cables (and only control wires to the alternate power offsite source) that are routed outside of switchgear in conduit.

The fire frequency was calculated using a combination of fixed and transient combustibles. For this switchgear room, the major source of damage is the cubicles themselves. Transient combustibles are of lesser concern because of procedural controls to limit transient combustibles and there is a cross zone detection system and a 100% coverage manual CO2 system.

The total fire frequency is partitioned according to the normal operating status of the cabinet and other features that determine the potential for fire. All loads were subjectively categorized into four groups according to their potential for fire. The first category is the equipment that is normally operating, requires internal cooling and has a high density of internal components; 2VBA*UPS2B and 2BYS*CHGR2B1. T he second group of components are normally operating but far from design capacity and have lower density of internal components; 2ENS*SWG103, 2EJS*US3, 2EJS*X3A and 2BYS*SWG002B. The third group of components are panels that are intermittently operating or not operating and are not near their design capacity; 2EHS*MCC303, 2EJS*PNL300B, 2EJA*XD301B and 2EJA*PNL301B. The last group consists of panels that are not normally operating or are at a minimal loading such as emergency lighting panels and transformers, the breaker test station, and the standby charger.

Later in this section, this information is used in developing the conditional frequency of a fire in electrical cabinet 2ENS*SWG103, given a fire in this room. It was decided that using a 1/20 conditional frequency (a total of 20 cabinets in Table 4.6-4 of the IPEEE) could be optimistic since the frequency of cabinet fires is probably dependent on the cabinet as discussed in the previous paragraph. If we assumed that the total fire frequency is dominated by the six cabinets identified in the first two groups, a 1/6 conditional frequency would be used. A 1/5 conditional frequency is used in the analysis described below.

The frequency of a fire within electrical cabinet 2ENS*SWG103 that causes loss of Div 2 AC power is estimated with the following equation:

FSWG103/A2 = F336XL * FSWG103 * [(3/11) + (8/11)*PF] = 9.7E-4 * (1/5) [(3/11 + (8/11)*0.1] = 6.7E-5/yr

Where:

FSWG103/A2 is the annual frequency of a fire in 2ENS*SWG103 that results in loss of Division 2 AC power (A2X initiator in the PRA)

F336XL is the sum total annual frequency of a fire in this room from all causes.

FSWG103 is the fraction of fires in the room associated with 2ENS*SWG103. Rather than utilize 1 in 20 cabinets as shown in Table 4.6-4, 1/5 is used based on the evaluation above.

PF is the probability of a fault causing loss of the switchgear. A value of 0.1 is used.

(3/11) and (8/11) are fractions of fires in 2ENS*SWG103 (cubicles) that lead to loss of bus from protective relay cubicles and other cubicles requiring an additional short, respectively. The development of these conditional frequencies is discussed above.

Core damage frequency can be estimated by taking the CCDP in the PRA for initiating event A2X times the above frequency for fires. The result is as follows:

6.7E-5/yr * 6.3E-5 = 4.2E-9/yr

If the probability of a fault is set equal to 1.0, core damage frequency would increase to 4E-8/yr.

Another bounding calculation was performed to check the possible upper bound frequency of fires that have minor impact initially, but manual suppression does not work and the fire propagates to have the impact assumed in the initial screening analysis. The result is as follows:

5E-7/yr*0.05 = 3E-8/yr

where 5E-7/yr is the core damage frequency in the initial screening analysis utilizing the total fire frequency for the room, assuming loss of Div 2 AC power, HPCS, and RBCLC, and taking no credit for suppression preventing propagation. The 0.05 value is the unreliability of suppression. Thus, the fire is assumed to keep burning to have this level of impact. This conservative bounding estimate indicates that core damage frequency will be less than 1E-7/yr even if spurious failure was increased to 1.0.

Evaluation of Cabinet Fire Impacts on Cables - during walkdowns, the potential for cabinet or panel fires to impact cables or conduits overhead was evaluated. This was done because cabinets dominate the frequency of fires in this room and a combination of impacts from the cabinet failure and cables nearby could be important. The following summarizes the conclusions of this evaluation:

- Some fires in the 4kV switchgear already result in a total loss of Div 2 AC power. The normal AC power cables are routed straight up toward the ceiling, above a cubicle that does lead to loss of Div 2 AC power, before being routed in trays. It is unlikely that any fire in this switchgear, which does not result in a total loss Div 2 AC power, would impact these cables.

- As described earlier, both RBCLC and normal AC power cables pass over 2BYS*SWG002B. Since RBCLC is much closer to the top of this cabinet, core damage frequency was estimated for the case where Div 2 DC power and RBCLC are both lost. Using a conditional frequency of 1/5, as used in the previous evaluation of cabinets above, core damage frequency is less than 1E-7/yr.

- Another less likely scenario would also include failure of normal AC power to Div 2. These cables are much higher, three trays above RBCLC. Again, core damage frequency was estimated for the case where Div 2 DC power, RBCLC and normal AC power to Div 2 are lost.

- Other cabinet fires would have much less impact than the cases identified above.

Division 1 Standby Switchgear Room (FA17 333XL) - This initiating event frequency for F333XL is 6.7E-5/yr and is based on assumed symmetry with Div 2 based on review comparison. The dominant scenario was determined to be loss of Divisional AC power due to switchgear fires that did not credit suppression.

The initial screening analysis assumed that Division 1 AC power and RCIC failed, given a fire in this location. The functional design of the electrical distribution system for Division 1 is essentially identical to the Division 2 functional design. Walkdowns and design reviews were performed to compare this area with the Division 2 room. The ceiling and cables in this room are very high. Cables enter the cabinets from the top as well as from underneath. There are 7 smoke detectors in this fire zone and a manual carbon dioxide total flooding suppression system. The Division 1 and 2 standby switchgear rooms each have the same number of cabinets with the same ratio of empty to deenergized cubicles. The relative locations of protective relay cabinets are essentially the same. There are some differences in the physical routing of conduits and raceways. The degree of separation or independence of cables associated with the offsite power sources and those associated with the diesel was evaluated to determine the number of locations where a fire can cause the loss of both offsite power and the failure of the diesel. There are no cable trays over the Division 1 125 VDC switchgear as there is in the Division 2 standby switchgear room and no RBCLC system cables.

Core damage frequency from the initial screening analysis is less than 1E-6/yr. This value is also less than the Division 2 switchgear screening analysis which was subsequently screened in the above Division 2 evaluation. Because these switchgear rooms are very similar with regard to design, cabinets, routing of normal AC and diesel cables, and fire impacts, this section does not provide the same level of detail as above for Division 2. Instead, the important attributes identified above for Division 2 that reduce the probability of core damage were checked by design review and walkdown. These important attributes include the fact that fire frequency is dominated by electrical cabinets, that normal AC power and diesel supply cables are separated such that failure of both is dominated by cabinet fires in specific cubicles, that the switchgear is similar to the Division 1 switchgear, and the room arrangements and configurations are very similar. Based on this review, the area easily screens below 1E-7/yr.

Division 1 Cable Chase West (FA16 332NW, 352NW & 371NW) – Two initiating events (FA16A and FA16B) are postulated for these rooms. FA16A is a fire near vertical cable trays that contain Division 1 and RCIC cables. The frequency (4.5E-5/yr) is based on the total for these rooms (4.5E-4/yr) times a spatial factor (10%) for a fire near vertical trays. FA16B is a fire near vertical cable trays that contain Division 1 and RCIC cables times the probability of automatic suppression failure (0.05) which allows normal AC power and the balance of plant to be affected. The frequency (2.3E-6/yr) is based on FA16A (4.5E-5/yr) times suppression failure (0.05).

The initial screening analysis assumed failure of Division 1 AC power and RCIC, given a fire in this location. T his was based on the Appendix R analysis which indicated that Division 1 and RCIC are impacted. The actual impact on Division 1 was not assessed. In addition, the BOP cable evaluation identified loss of offsite power and other balance of plant systems being lost. A walkdown was performed to investigate a more realistic evaluation of impacts. T he ceiling and horizontal cable trays in this room are high. Taking credit for automatic suppression (0.05 unavailability assumed) in these rooms would result in a core damage frequency less than 1E-7/yr still assuming the worst impact as in the initial screening analysis. Note that only IEEE 383 cables are used and for most fires it is not expected that impacts would occur away from the fire (i.e., hot gas layers, etc) even without suppression (i.e. fire burns out). For these reasons, the focus of the evaluation in these rooms is on identifying impacts that could occur before detection and suppression. This includes electrical cabinet fires and noncabinet fires near the floor as described below.

The following summarizes detection and suppression in each zone:

Fire Zone	Number of Detectors		Type of Automatic Fire Suppression	
	Temp	Smoke	Area Water Sprinkler	Cable Tray Water Spray
332NW	0	5	No	Yes
352NW	0	4	Yes	Yes
371NW	0	4	Yes	Yes

Electrical Cabinet Fires - The frequency of a fire in each zone is dominated by electrical cabinet fires. Therefore, the impact of a fire in each cabinet was assessed and is summarized in Table 4.6-5 of the IPEEE. Only impacts judged to potentially influence the PRA are noted and in many cases the impacts are based on conservative assumptions (i.e., a cabinet supplies main steam circuits and it was assumed that MSIVs close and condenser is unavailable even though the circuit impacts were not evaluated). In addition, the proximity of cables to cabinets was evaluated during walkdowns and included in Table 4.6-5 of the IPEEE. If the cabinet is closed (not vented) no additional impacts were considered. In the case of vented electrical cabinets, conduits and cable trays within about 5 feet of the cabinet were considered for the plume and 1.5 feet from the cabinet for radiation heat transfer.

One important finding from this evaluation is that normal AC power is not affected by cabinet fires. This finding alone would reduce the frequency of core damage from cabinet fires below 1E-7/yr. Also, the loss of all Division 1 equipment was not found to occur due to a single cabinet fire. Thus, the modeling of impacts by cabinet and considering the frequency of a fire/cabinet would further reduce core damage frequency.

Noncabinet Fires - The frequency of fire due to other causes such as transients, welding, and junction box/splices are about an order of magnitude less than cabinets. In fact, if this non cabinet frequency was used in the initial screening, these rooms would screen out at 1E-7/yr. Because of this, it was decided to judgmentally consider a spatial reduction factor to completely screen these rooms. When considering the floor area where fires could potentially impact Div 1 cables (i.e., vertical trays or conduits near the floor) before suppression would occur, it was judged that 10% of the floor area could potentially cause some damage. Assuming that these fires are as likely to occur any place on the floor area, this would reduce core damage frequency less than 1E-7/yr. Note that this is conservative because it still assumes that for all these fires the worst case impacts also occur as in the initial screening analysis. A more realistic assessment could consider those areas where both offsite power (loss of offsite power reduces the reliability of Div 2) and Div 1 cables are located which would reduce the spatial reduction factor even further. Thus, identifying those areas where normal AC power and Div 1 can be impacted would produce a smaller spatial reduction factor. For those areas where a fire does not affect both offsite power and Div 1, core damage frequency estimates for these scenarios would be much less. Finally, assuming that loss of Div 1 cables lead to a total loss of Div 1 equipment is still conservative.

Division 2 Cable Chases (FA18 304NW, 324NW, 337NW, 359NW, 377NW & FA19 323NW) - Two initiating events (FA18A and FA18B) are postulated for these rooms. FA18A is a fire near vertical cable trays that contain Division 2 and HPCS cables. The frequency (4.5E-5/yr) is based on the total for these rooms (4.5E-4/yr) times a spatial factor (10%) for a fire near vertical trays. FA18B is a fire near vertical cable trays that contain Division 2 and HPCS cables times the probability of automatic suppression failure (0.05) which allows normal AC power and the balance of plant to be affected. The frequency (2.3E-6/yr) is based on FA18A (4.5E-5/yr) times suppression failure (0.05).

The initial screening analysis assumed failure of Division 2 AC power and HPCS, given a fire in one of these locations. This was based on the Appendix R analysis which indicated that Division 2 and HPCS are impacted. The actual impact on Division 2 was not assessed. In addition, the BOP cable evaluation identified a partial loss of offsite power and other balance of plant systems being lost. The following summarizes detection and suppression in each zone:

Fire Zone	Number of Detectors		Type of Automatic Fire Suppression	
	Temp	Smoke	Area Water Sprinkler	Cable Tray Water Spray
304NW	0	4	Yes	Yes
324NW	0	4	Yes	Yes
337NW	0	5	No	Yes
359NW	0	5	Yes	Yes
377NW	0	3	Yes	Yes
323NW	0	15	No	Yes

These compartments are similar to the Division 1 Cable Chase West compartments described above. However, the frequency of core damage is less for these Division 2 areas which means that smaller reduction factors are needed to screen these areas. Rather than document impacts of cabinets in detail, as done in Table 4.6-5 of the IPEEE for the Division 1 areas, a walkdown and review was performed to assure that cabinet impacts are similar to those in the Division 1 areas (i.e., symmetry) and to investigate the proximity of vented cabinets to cable trays and conduits. Note that 337NW, 359NW and 337NW are symmetrical to those Division 1 zones described above. There were very few cabinets in the other zones. Based on this review, it was concluded that the approach taken for the Division 1 areas also applied in these areas as summarized below:

- Taking credit for automatic suppression (0.05 unavailability assumed) in these rooms would result in a core damage frequency less than 1E-6/yr still assuming the worst impact as in the initial screening analysis. Note that only IEEE 383 cables are used and for most fires it is not expected that impacts would occur away from the fire (e.g., hot gas layers, etc.) even without suppression (i.e., fire burns out).

- The configuration of zones 337NW, 359NW and 337NW is similar to the Division 1 zones evaluated above and the impact of cabinet fires is similarly symmetrical. No significant new scenario was identified from the walkdown and review of cabinets. Thus, these zones can be screened out for the same reasons developed above.

Thus, fire zones 304NW, 323NW and 324NW can also be screened for the same reasons developed above.

Normal Switchgear Rooms (FA51 601XL, FA52 602XL, FA78 612XL & FA79 613XL) – According to the analysis, suppression would have to fail in order to impact sufficient cables to cause a total loss of offsite power. Such a scenario is postulated for initiating event FNSGR where the frequency is the sum of the 4 rooms (FA51 601XL, FA52 602XL, FA78 612XL & FA79 613XL), 4E-3/yr, times the probability of suppression failure (0.05) which equals 2E-4/yr. Normal AC is set to guaranteed failure without recovery.

The initial screening analysis assumed that normal offsite power and balance of plant systems failed, given a fire in this location. Although the most recent screening indicates these compartments can be screened, they are retained due to potential importance to the proposed amendment. The frequency of fires is dominated by electrical cabinet fires similar to other areas evaluated previously. With the exception of FA52 which has MG sets that contribute, electrical cabinets dominate by an order of magnitude. Thus, the screening of these areas concentrated on electrical cabinets and the MG sets similar to other analyses. Each fire zone has smoke detectors and a manual actuated total flooding carbon dioxide suppression system. The fraction of fires that cause a total loss of offsite power versus partial loss of offsite power or even less impacts is the key to this analysis. Fires that cause a partial loss of offsite power would screen out at less than 1E-7/yr.

Based on the above and previous analysis, walkdowns and design reviews were performed to develop confidence that a reduction factor of at least 1/10 could be developed for cabinet fires that cause total loss of offsite power. No single cabinet was identified that could cause a total loss of offsite power. Cable trays were identified that could lead to total loss of offsite power, however, the manual suppression system provides confidence that propagation and damage to cable trays is unlikely. The following summarizes walkdown and design review conclusions:

- FA51 - This fire area contains the chargers and switchgear that is associated with the 125 VDC systems 2BYS-SWG001A and 2BYS-SWG001B. The power cables for 2NNSSWG016 are routed through this area. There are numerous cables associated with the 115kV motorized disconnects. A fire in this area results in the loss of offsite power to 2ENS*SWG101 due to cables - cabinet fires do not fail offsite power supplies. Loss of balance of plant systems should be assumed since this was not evaluated.

- FA52 - A fire in this area can result in a total loss of offsite power due to control cables - cabinet fires do not fail offsite power supplies. Power cables to both 2NNS-SWG016 and 017 are routed in this area; there is approximately 50 feet separation between the cables (cables to SWG016 are routed on the opposite end of the room from SWG017 cables). Loss of balance of plant systems should be assumed since this was not evaluated.

  This area contains the grounding transformers for the main supply transformers from offsite power, the feeder cables for buses 2NNS-SWG016, 017, the motor generator sets for the RPS power, two non-safety UPSs, UPS3A & B, the grounding transformers for the 4.16kV busses 2NNS-SWG016, 2NNS-SWG017, 2NNS-SWG018 and the four non-safety UPSs, UPS1A,B,C,D.

  Loss of a grounding transformer, by itself, will not result in loss of offsite power to the associated bus. The AC power system for this bus is delta connected and is not grounded. For a fire to cause the loss of the associated offsite power bus, another concurrent failure in a power feed must occur in addition to a fault in the grounding transformer power cable.

Loss of the RPS UPSs 2VBB-UPS3A & 3B will result in reactor trip and vessel isolation. There are a few cables 15 ft directly above the UPSs. At higher elevations there are more cables.

Loss of the BOP UPSs is conservatively assumed to result in loss of the BOP systems.

The offsite power cables supplying power to both Division 1 & 2 4kV busses pass through this room. There is approximately 50 feet separation between these power cables at the point of closest approach. The intervening space between the tray routes has a small combustible loading, consisting of horizontal cable trays.

The control cables for the motorized disconnects in the 115kV switchyard are impacted by a fire that affects either trays 2TC850N or 2TC855N. If the fire causes wire to wire short circuits then the motorized disconnects will open and not be able to be reclosed. A minimum of two disconnects opening (2YUC-MDS3 or 2YUL-MDS1 and 2YUC-MDS4 or 2YUL-MDS2) isolate the plant from offsite power. In this case, offsite power is not recoverable.

- FA78 - A fire in this area can result in a total loss of offsite power due to control cables - cabinet fires can cause a partial loss of offsite power (loss of 2NNS-SWG016 supply). Loss of balance of plant systems should be assumed since this was not evaluated.

- FA79 - A fire in this area can result in a total loss of offsite power due to control cables - cabinet fires can cause a partial loss of offsite power (loss of 2NNS-SWG017 supply). Loss of balance of plant systems should be assumed since this was not evaluated.

Remote Shutdown Room B East (FA19 338NZ) - This initiating event (F338NZ) frequency is 1.5E-4/yr. Loss of Div 2 service water pumps, RCIC due to SRV actuation, and RHR B are modeled for this initiator.

The initial screening analysis conservatively assumed that Division 2 AC power was impacted by a fire in this zone. Since the actual impact was not evaluated, this was performed first.

The remote shutdown panel 2CES*PNL405 contains both remote shutdown divisions that are separated by a three hour fire wall. This panel contains transfer switches and controls. Panels 2CES*PNL415 & 2CES*PNL416 are not located within the remote shutdown room. They contain isolation switches that prevents spurious operation where needed and it provides isolation for circuits that need manual actuation for remote safe shutdown. The design bases for these switches assume that the switches are transferred before their circuits are impacted by the control room fire. A fire at either panel causes loss of all circuits connected to the panel. For the control room fire, two switches at 2CES*PNL415 or 416 and at the remote shutdown panel must be thrown to recover a service water pump. The 2CES*PNL415/416 switches isolates unwanted control room contacts and the transfer switch isolates the operation features.

A fire at the remote shutdown panel could cause loss of Divisional service water (the three Divisional pumps trip and/or lose control power). These pumps cannot be operated from the control room. Additionally, the fire can cause actuation of an SRV (1 or more of 4 SRVs). Loss of control power to one solenoid is not a concern because the SRVs have three solenoids (two from Division 1 and one from Division 2 that can actuate the valve). There is a possibility that these valves cannot be closed if they spuriously open. A RHR pump can be lost due failure of control cables.

Diesel generator backed AC power is not directly impacted by a fire in 2CES*PNL405. AC power components are isolated by either 2CES*PNL415 or 2CES*PNL416, both located in different fire areas from the remote shutdown panel.

Two smoke detectors are provided with no automatic suppression. This is a small room with the impacts concentrated at one panel. For this reason no credit for suppression before impact was considered. A fire initiator (FA338 = 1.5E-4/yr) was run through the PRA model as follows:

Loss of Division 2 service water pumps
Loss of RCIC due to ADS actuation
ADS success
Loss of RHR B

The resulting core damage frequency from FA338 is less than 1E-7/yr.

The above calculation is conservative. ADS actuation requires hot shorts with a probability which was not applied (i.e., 0.1). Allowing RCIC to succeed and requiring the operators to actuate ADS would lead to a core damage frequency estimate comparable to or less than calculated for the above case.

Remote Shutdown Room A West (FA17 343NZ) - This initiating event (F338NZ) frequency is 1.5E-4/yr. Loss of Div 1 service water pumps, RCIC due to SRV actuation, and RHR A are modeled for this initiator. Although this compartment screened during initial screening, this initiator was added to include symmetry with the Div 2 remote shutdown panel.

Reactor Building (FA34 212SW, 222SW, 232SW, 243SW & 252SW) - Similar to other locations, the total impacts associated with each zone were assumed to occur in the initial screening. The impacts include loss of Division 1 ECCS (RHR, LPCS, ADS), RCIC and balance of plant systems (RBCLC, main condenser, and feedwater). Each fire zone represents one half of a reactor building floor elevation which is a large area. The total frequency of a fire in FA34 is about 3.9E-2/yr. The initial screening analysis used a fire frequency of 1E-2/yr for each fire zone (assumed to be a reasonably conservative estimate) which led to a core damage frequency of less than 1E-6 for some zones. The reactor building was screened out by inspecting dominate (highest frequency) fire sources and the proximity of potential important targets during a walkdown. The strategy and walkdown notes are provided below.

Automatic cable tray water spray suppression is provided in each zone. The following summarizes the detectors in each fire zone:

Fire Zone	Number of Detectors	
	Temperature	Smoke
212SW	13	34
222SW	0	39
232SW	5	32
243SW	5	38
252SW	0	39

The frequency of a fire in FA34 is based on the following fire source frequencies (events/yr):

H2 Recombiner 2.9E-2
Pumps 6.4E-3
Elec Cabinet 2.1E-3
Compressors 5.9E-4
Ventilation/Fans 4.1E-4
Transformers 2.8E-4
JB/Splice 2.5E-4
Weld/ORD 2.0E-4
Weld/CAB 6.0E-5
Transients 4.1E-5

The initial screening analysis did not demonstrate that the fire zones meet the definition of a fire compartment in FIVE. However, core damage frequency results for the upper elevations screened out of the initial screening analysis and are not sensitive to the total fire frequency for area FA34. Also, given the size of these areas, height of the ceilings, and the floor openings, the accumulation of hot gases is difficult. During the walkdown, the proximity of cables to the ceiling and the potential for gas accumulation were considered and no important configurations or impacts were identified. This fire area was evaluated utilizing the following strategy:

- Those fire sources with frequencies less than 1E-3 can be screened out. The total frequency of these other causes is on the order of 1E-3/yr; assuming the total impact as in the initial screening analysis, core damage frequency would be less than 1E-7/yr. However, during the walkdown, the proximity of compressors, ventilation/fans, and transformers to cables and other important systems were inspected to obtain confidence that fires from these sources cannot have the impact assumed in the initial screening analysis. Also, junction boxes and splices (JB/Splice) are typically contained in enclosures without vents which mean that these fires are expected to have only limited local impacts. This evaluation provides confidence that core damage frequency from these lower frequency sources is less than 1E-7/yr.

- Starting at elevation 175 (lowest elevation), each fire zone was inspected for the high frequency sources and their proximity to other important equipment and cables (i.e., radiant and plume impacts). Also, ceilings/overheads were visually inspected for the potential of hot gas accumulation and flow. During the walkdown, automatic cable tray water spray suppression capabilities were confirmed where important.

- When conduits or cable trays were found in close proximity to a source (<5 feet from electrical equipment), they were not considered important unless there is a mixture of safety (green and/or yellow) with non-safety (black). If the fire does not impact safety and non-safety (balance of plant), the fire can be easily screened.

Each elevation was walked down with no distinction made between fire areas 34 and 35. The impacts identified during the walkdown were evaluated (i.e., cable raceway database, CRS2, was used to identify cables within a raceway and the elementary and/or wiring diagrams used to identify impact). Based on impacts, fire frequency, and the PRA, FA34 was screened out.

Reactor Building (FA35 213SW, 223SW, 238SW, 245SW & 255SW) - This fire area is similar to FA34 described in the previous section. Similarly, the total impacts associated with each zone were assumed to occur in the initial screening. The impacts include loss of Division 2 ECCS (RHR, ADS), HPCS, and balance of plant systems (RBCLC, main condenser, and feedwater). Each fire zone represents one half of a reactor building floor elevation which is a large area. The total frequency of a fire in FA35 is about 3.8E-2/yr. The initial screening analysis used a fire frequency of 1E-2/yr for each fire zone (assumed to be a reasonably conservative estimate) which led to a core damage frequency of 8E-6/yr for some zones.

Automatic cable tray water spray suppression is provided in each zone. The following summarizes the detectors in each fire zone:

Fire Zone	Number of Detectors	
	Temperature	Smoke
213SW	20	35
223SW	0	39
238SW	1	32
245SW	2	37
255SW	4	33

The frequency of fires in FA35 is based on the following sources and frequencies (events/yr):

H2 Recombiner 2.9E-2
Pumps 4.1E-3
Elec Cabinet 2.1E-3
Elevator Motors 1.6E-3
Ventilation/Fans 5.3E-4
Transformers 5.7E-4
Compressors 3.9E-4
JB/Splice 2.2E-4
Weld/ORD 2.0E-4
Weld/CAB 6.0E-5
Transients 4.1E-5

The strategy for evaluating this fire area is the same as described in the previous section for FA34.

Service Water Pumps (FA60 807NZ & FA61 806NZ) - For each of these zones, the initial screening analysis assumed failure of the Division 1 service water header and pumps similar to the PRA initiator SAX. A fire initiating event frequency in each zone is equal to 6E-3/yr and leads to a CDF value of <1E-7 in each zone (symmetry between Div 1 and 2 is assumed). There are six smoke detectors provided for each fire zone with no automatic suppression.

A walkdown was performed to assess the location of fire sources that dominate the fire initiating event frequency to determine more realistic impacts of fires. It was noted prior to the walkdown that the fire frequency was dominated by electrical cabinets and pumps. The total frequency of other fire causes is about an order of magnitude less likely and a more detailed evaluation of these causes and impacts would likely result in additional reduction factors.

With regard to pump and electrical cabinet fires, the following summarizes the walkdown observations:

- The pumps are in a deep pit about forty feet below the deck (El 261) where most of the remaining service water equipment (strainers, MOVs, MCC, cable trays) is located. There is another elevation above the deck where hot gases would tend to collect given a fire in the area. There is no important equipment or cables at this higher elevation.

- There is sufficient distance between the three pumps, their associated cables, and other critical equipment on the upper deck such that a fire initiated at one pump is very unlikely to impact a second pump let alone all three as assumed in the screening analysis. The only conceivable scenario that could impact more than one pump might be a pump fire and oil spill onto the floor. However, there is limited oil associated with a pump motor and the surface area associated with oil spread on the floor to impact all three pumps is large. This may not even be credible, but if it is, the frequency of such an event is less than assumed in the screening analysis. In addition, the safety related header supplies are not impacted. Our judgment is that pump fires that impact all three pumps are unlikely and can be screened out (core damage frequency <1E-7/yr).

- There are two large unit coolers (e.g., 2HVY*UC2A & C in FA61) below the deck at El 261, but above one of the pumps. The initiating frequency for a unit cooler fire is less than the frequency for the pumps and the impact would likely be only one pump. Therefore, this source can be screened as stated above.

- The major electrical cabinet in each area is the MCC (e.g., 2EHS*MCC101 in FA61) on the deck at El 261. The MCC is actually contained within another cabinet, thus the impact of fires within the MCC are very unlikely to impact cable trays above the MCC. No vented cabinets that could impact cables or conduits were identified during the walkdown.

- Each MCC supplies Divisional strainers, strainer MOVs, pump discharge MOVs, unit coolers, a crosstie MOV, header MOVs and tunnel heaters. There are no cables that would depower the pumps and since service water is normally operating (MOVs are in their correct position for normal operation), a fire would have to cause a short circuit to have an impact on system operation (i.e., shorts cause pump discharge MOV or header MOV to close). The probability of a short is less than 1.0. In addition, the frequency of a fire that impacts more than one MCC cubicle causing loss of two or more pumps, or loss of pumps and header supplies is much less than the frequency used in the screening analysis. All these factors are judged to lead to core damage frequencies less than 1E-7/yr.

Based on the above analysis and walkdown observations, it is judged that core damage frequency in each area due to fires is easily <1E-7/yr.

Corridors and Instrument Shop El 288 and 306 of CB - As a result of performing the screening analysis using the latest CAFTA model and using a 1E-7 screening value, the following new compartments required evaluation; they assumed the same conservative impacts as other zones in the area:

Area	Zone	Description	Screening Value
72	351.1NZ	Instrument shop El 288 CB	2.7E-7
72	351.2NZ	Corridor El 288 CB	2.7E-7
76	380.2NZ	Corridor/toilet El 306	2.7E-7

These areas were reviewed, including walkdowns to inspect cabinets in the corridors. There are no cable trays in these corridors and no PRA impacts were identified. Appendix R (UFSAR Appendix 9A) confirms that there are no safety related impacts in these areas. As a result, CDF is clearly less than 1E-7/yr.

ATTACHMENT A2-C

REVIEW OF INDUSTRY-GENERIC MSOs APPLICABLE TO DG-RELATED EVENTS

MPL	#	Generic Scenario	Generic Notes	Evaluation
E12	5a	Additional components load onto credited diesel generator	Scenario causes diesel generator overloading and inoperability. Note: Scenario very site specific. Interlocks may prevent this from occurring. In addition, overloading may also occur if proper load sequencing is bypassed via hot shorts, causing simultaneous loading of multiple components onto the DG.	**This MSO concern is <u>not</u> applicable to NMP2.** Simultaneous loading of attached loads to the diesel. NMP2 does not have a sequencer. It does have sequencing logic that consists of several relays. NMP2 has no load sequencer for operation under the loss of off-site power. Therefore, there may be concern for spurious operation of some of the large loads that may be loaded spuriously which could cause a DG stall condition. NMP2 does not load DGs for either LOCA or LOOP scenarios through any load sequencer pre programmed devices. Logic circuits for these sequencing circuits are routed from PNL 415, 852 (Relay RM) and 609 (at MCR) to the respective switchgear. 2ENS*SWG101 and 102 loadings include RHR pumps, SWP, SFP pumps, and LPCS. Each DG is rated for 4750 KW for 2000 hrs of operation. A LOOP will pickup UVR27 which will trip all loads feeder breakers at the switchgear (except 600V SST feeder breakers). A loop sets a time delayed relay, then closes each load feeder breaker after bus is powered by the DG. All the control cables to these switchgear are separated and isolated from one another according to the NMP2 Electrical separation criteria. Each division of control circuits from CR/RR to switchgear maybe routed within the same cable or raceway since separation is not required within the same division; therefore, when one division of power source was selected for safe shutdown, all associated circuits such as these control circuits were considered. Therefore, as such, this MSO concern was included in the evaluation concept of original safe shutdown analyses. At most, it was anticipated that a failure in one division of power source cannot impact other division. The same argument applies to the control room/relay room fire and control room evacuation.

MPL	#	Generic Scenario	Generic Notes	Evaluation
R43	5f	Non-synchronous paralleling of DG with on-site and off-site sources through spurious breaker operations	Scenario causes damage to diesel generator by closing into a live bus out-of-phase. Note: Scenarios are very site specific. Interlocks may prevent this from occurring.	Spurious start of the DG and spurious closure of the feeder breaker. 2EGS*EG1 2ENS*SWG101-13, -10, -1 2EGS*EG3 2EGS*EG2 2ENS*SWG103-2 -4, -14 Based on modifications made to the plant and physical separation of control cables associated with emergency switchgear, the likelihood of this scenario is very low. At NMP2, modifications were implemented as part of the plant original compliance and safe shutdown analysis to prevent connecting offsite power to the DGs when they are not synchronized. This was accomplished by an additional permissive (contact in the control circuit) in the DG breaker control circuit that would prevent fire induced spurious closure of the breaker if offsite power is available at the emergency busses. This modification precludes this scenario from occurring during and following a control room fire event. For a postulated fire outside the control room, the likelihood of this scenario is very low due to physical separation of control cables associated with the emergency switchgears. The divisional switchgears and associated breakers are located in separate fire areas. For an auto-start of a DG, the diesel breaker cannot close unless the bus (normal feed) breakers are both open. There is a contact on the diesel breaker circuit that prevents it. Operations can close the diesel breaker manually, but there is another contact that forces them to turn on the Sync scope in order to close the breaker. This is procedurally controlled.

MPL	#	Generic Scenario	Generic Notes	Evaluation
R43	5g	Non-Synchronous Paralleling - inadvertent cross-tie breaker operation between opposite divisions (e.g., 4160V, 480V) of Div 1(2) DGs through Spurious Operation of 480 V Breakers or the Divisional Cross-Tie through 4160 V Maintenance Tie Breakers	Scenario causes damage to diesel generator by closing into a live bus out-of-phase. Note: Scenario very site specific. Interlocks may prevent this from occurring.	**This scenario is not credible at NMP2.** EE-MO01A, B On a given emergency bus there is only one breaker for the two feeds. There are no maintenance tie breakers.
R43	5h	Cross-tying the offsite power sources through the on-site busses & breakers	Spurious breaker closings between separate divisions of off-site power.	**This scenario is not credible at NMP2.** EE-MO01A, B In order to cross tie, an extra breaker has to be inserted into the second cubicle. That is an abnormal line up.

MPL	#	Generic Scenario	Generic Notes	Evaluation
R43	5i	Spurious diesel generator operation without cooling water	The fire causes the startup of the Diesel Generator. Spurious closure of the ESW Pump Discharge Valve or trip of the ESW Pump would stop the cooling water supply to the Diesel Generator. Running the Diesel Generator with a loss of cooling water could trip the diesel on high temperature. If the fire has resulted in the actuation of a LOOP or LOCA bypass of the high temperature trip, the diesel could continue to run until damage from over-temperature conditions stop it.	PID 11L Only 5 minutes are available if the DG is loaded, 15 minutes if half loaded, or 30 minutes if not loaded. The spurious start of the DG can occur for a fire in panel 852 in the MCR and in DG control panel in DG control room. MOV 95A AND MOV 95B have to fail for EG2 MOV 94A AND B have to fail for EG2 MOV 66A for EG1, MOV 66B for EG3, MOV 94A, B, MOV 95A, B for EG2 Operators can manually open MOV 66A and MOV 66B. As previously noted, this would take less than 5 minutes based on alarms in MCR. Div 1 and 2 DGs can also run longer than 5 minutes fully loaded based on previous operating experience. • If the diesel was started due to a short and not an actual LOP/LOCA condition, Operations could simply shut it down manually. • If it was due to a LOCA circuit short, there is the LOCA over-ride that can be used to shut it down. • If the diesel was manually shut down, it would still be able to be started manually, if required. • If there is a start with no LOP, the normal feed breaker to the switchgear would still be closed, blocking closure of the diesel breaker. The diesel would be totally unloaded. • Operations can open the MOV94A/B or MOV95A/B as required – they are local in the diesel rooms. • An operator would have to be stationed at the diesel panels to ensure proper start or stop of the diesel(s). • The override of the high temperature shut off does not mask the alarm. Operators would still see the alarm and could shut the diesel down – assuming there is not a LOP.

MPL	#	Generic Scenario	Generic Notes	Evaluation
				• If there is a false start with no LOCA, the loading on the diesel would be minimal – just 2 service water pumps. The 15 to 30 minute duration would be appropriate for operation with no cooling.
				The current NMP2 safe shutdown analysis demonstrates the availability of one train of safe shutdown capability including support system such as electrical distribution and service water systems. In order for a fire event to cause the postulated scenario (i.e., spurious DG start without SW), it has to cross divisional boundaries. The current divisional separation at NMP2 is such that a postulated fire can potentially cause this scenario in only one division of safe shutdown system/train. There are 2 divisions of electrical distribution and service water systems. Each division's components, associated controls, and cabling are separated from the redundant division in accordance with 10CFR50, Appendix R III.G.2 requirements. For a control/relay room fire, the existing control room evacuation procedure (N2-SOP-78) includes steps for plant operators to verify at the diesel control panel the proper start and control of DGs, including verification of service water supply.

ATTACHMENT A2-D

IMPORTANT OPERATOR ACTIONS

A detailed evaluation of HEPs in the internal events PRA for fires has not been completed for the NMP2 Fire PRA. Thus, the most important operator actions were identified and evaluated to determine whether there is an important operator action that could be effected when considering response during a fire. The following table provides a list of operator actions with a RAW greater than 2 with Division 1 DG out of service and with Division 2 DG out of service (this was done 1[st] with CDF with Division 1 DG out of service; blanks indicate RAW is less than 2). It is assumed that a fire could cause some confusion and delay with the operating crew at least early during the event. Thus, those operator actions required less than an hour after a plant trip were considered potentially important for further evaluation.

Based on this review, operator actions **ZOD01**, **ZSA01**, and **ZHS04** were identified for further evaluation – refer to Table A2-D.1. A sensitivity analysis was performed where fires risk was quantified with these operator actions increased by a factor of 10 for the amendment analysis. The results show that there is very little change between the base case results and the factor of 10 increase, as shown in Table A2-D.2.

Table A2-D.1: Important Operator Actions

Event Name	CDF1 RAW	CDF2 RAW	LERF1 RAW	LERF2 RAW	Description	Evaluation
ZOD01_ODOPERATOR	24.09	18.22	101.12	87.85	Operator Fails to Manually Depressurize (Transient)	30 min
ZHRA1_HROPERATOR	23.11	17.66	4.03	3.64	Operators Fail to Successfully Respond to Control Room Fire	Fire specific HEP
ZIC02_ICSBYPTEMP	8.69	6.62	8.11	6.94	Operator Fails to Bypass RCIC Trip on High RHR Area Temperature – SBO	Required within 15 min per SOP-1, but RCIC success for even 15 minutes and then trip would provide additional time and a cue to re-start and trip high area temp trips.
ZIC04_OPEN_DOOR	7.96	6.07	6.97	5.96	Operator Fails to Open RCIC Room Doors Given SBO	Required within 2 hours per SOP-1
ZHRA2_HROPERATOR	6.36	5.04	2.02	<2	Operators Fail to Successfully Respond to Control Room Fire	Fire specific HEP
ZSA01_SWOPERATOR	5.99	5.05	<2	<2	Operators Fail to start a SW Pump	30 min
ZHS05_HSROOMCOL	3.6	4.47	3.26	4.63	Operator Fails to open HPCS Room Doors and HVAC Duct	About 1 hour based on room heat up and this ZHS04 must be successful and will be a further cue to perform this action
ZHS04_EDGCOOLING	3.38	4.29	2.61	4.08	Operator fails to protect DG From High Temp During SBO	15 to 30 min assuming that ZHS03 is not already aligned
ZOH03_OHOPERATOR	3.34	7.31	<2	<2	Operator Fails to Align RHR Early (To Avoid HCTL)	Several hours available
ZHS03_HSDGOPERTR	3.26	4.07	3.12	4.36	Operator Fails to Align Fire Water for DG Cooling	Assuming ZHS06 is successful; operators have close to an hour to perform this alignment.

Table A2-D.1: Important Operator Actions

Event Name	CDF1 RAW	CDF2 RAW	LERF1 RAW	LERF2 RAW	Description	Evaluation
ZOLS1_LOADSHEDDC	3.14	2.49	3.09	2.6	Operator Fails to Conduct DC Load Shedding Procedure	This should start within an hour after SBO, but this could be delayed at least an hour based on conservatisms in the model regarding battery life.
ZHS06_HPCSLV8SBO	2.95	4.5	2.7	4.75	Operator Fails to Allow HPCS to Run for Init Level Restoration in SBO	Operators would have to consciously prevent HPCS operation, which is judged unlikely
ZMA01_OPENRMDOOR	2.48	2.12	<2	<2	Operators Fail to Open ECCS Room Doors Given High Temp Annunciator	Several hours available
ZCV02_CVOPERATOR	2.4	2.52	<2	<2	Operators fail to align containment venting when air or Div 1 AC unavailable	Several hours available
ZCV01_CVOPERATOR	2.36	2.49	<2	<2	Operators fail to align containment venting when all support systems are available	Several hours available
ZA301DCRDOOR	2.3	2.22	3.01	2.13	Operator Fails to Manually Open DG Room Door or Supply MOV	15 min is conservatively used for HEP. An operator is dispatched to DG when it starts; **Compensatory measure used for AOT**
ZCV06_PPSWPCVENT		2.15	<2	<2	Operator Fails to Vent PC (Local Actions including use of Port. power-pack)	Several hours available
ZOD04_ODOPERATOR	<2	<2	3.74	3.38	Operator Fails to Manually Depressurize (SLOCA)	Fire induced small LOCA is very unlikely
ZIS03_SBOE-FAIL-	<2	<2	2.94	4.23	Operator Fails to Locally Close MOVs (SBOE)	Initiated at RPV level at TAF (30 min) per SOP-1; **Compensatory measure used for AOT**
ZAI01_AIOPERATOR	<2	<2	2.31	2.14	Operator Fails to Inhibit ADS (ATWS)	Fire induced ATWS is very unlikely

Table A2-D.2: Operator Actions ZOD01, ZSA01 & ZHS04
HEP Increased by a Factor of 10

Value	AOT Base Case	HEP x 10	Acceptance Criteria
ΔCDF_{ave}	2.85E-07	2.88E-07	<1E-6
$\Delta LERF_{ave}$	2.23E-08	2.26E-08	<1E-7
$ICCDP_1$	2.16E-07	2.18E-07	<5E-7
$ICCDP_2$	3.31E-07	3.34E-07	<5E-7
$ICLERP_1$	1.88E-08	1.90E-08	<5E-8
$ICLERP_2$	2.40E-08	2.43E-08	<5E-8

ATTACHMENT 3

COMPARISON OF THE NMP2 SEISMIC PRA MODEL TO THE TECHNICAL ELEMENTS OF REGULATORY GUIDE 1.200, REVISION 2, SECTION 1.2.6

Nine Mile Point Nuclear Station, LLC
June 1, 2010

Regulatory Guide 1.200, Rev. 2 (Table 7)		NMP2 Assessment
Element	**Technical Characteristics and Attributes**	
Probabilistic Seismic Analysis	1. Seismic hazard analysis a. establishes the frequency of earthquakes at the site b. site-specific c. examines all credible sources of damaging earthquakes d. includes current information e. based on comprehensive data, including geological, seismological, and geophysical data, local site topography, historical information f. reflects the composite distribution of the informed technical community g. level of analysis depends on application and site complexity 2. Aleatory and epistemic uncertainties in the hazard analysis (in characterizing the seismic sources and the ground motion propagation) properly accounted for fully propagated allow estimates of fractile hazard curves, median and mean hazard curves, uniform hazard response spectra 3. Spectral shape used in the seismic PRA based on a site-specific evaluation broad-band, smooth spectral shapes for lower-seismicity sites acceptable if shown to be appropriate for the site uniform hazard response spectra acceptable if it reflects the site-specific shape 4. Need to assess whether for the specific application, other seismic hazards need to be included in the seismic PRA, such as fault displacement landslide, soil liquefaction soil settlement	Seismic hazards developed by EPRI and NRC (see references below) were used to develop seismic initiating events. The hazard estimate depends on uncertain estimates of attenuation, upperbound magnitudes, and the geometry of the postulated sources. Such uncertainties are included in the hazard analysis by assigning probabilities to alternative hypotheses about these parameters. A probability distribution for the frequency of occurrence is thereby developed. The hazards are discretized and used as initiating events in the PRA accident sequence analysis. The following summarizes the point estimate initiating events as developed in the PRA: **EPRI HAZARD** Initiator / Acceleration Range (g) / Mean Annual Frequency SEIS1 / 0.01-0.05 / 1.46E-2 SEIS2 / 0.05-0.10 / 2.87E-4 SEIS3 / 0.10-0.25 / 6.61E-5 SEIS4 / 0.25-0.51 / 6.21E-6 SEIS5 / 0.51-0.71 / 5.10E-7 SEIS6 / 0.71-1.02 / 1.44E-7 The following provide the hazard analysis details and results: • EPRI NP-6395-D, April 1989, "Probabilistic Seismic Hazard Evaluations at Nuclear Plant Sites in the Central and Eastern United States: Resolution of the Charleston Earthquake Issue," Prepared by Risk Engineering, Inc., Yankee Atomic Electric Company, and Woodward-Clyde Consultants. • NUREG-1488, "Revised Livermore Seismic Hazard Estimates for 69 Nuclear Power Plant Sites East of the Rocky Mountains"" Final Report, April 1994. ***GAP****: These are generic issues associated with hazard development and its impact on plan fragility that should be considered in future updates. However, these issues do not impact this application.*

EPRI HAZARD (table within NMP2 Assessment):

Initiator	Acceleration Range (g)	Mean Annual Frequency
SEIS1	0.01-0.05	1.46E-2
SEIS2	0.05-0.10	2.87E-4
SEIS3	0.10-0.25	6.61E-5
SEIS4	0.25-0.51	6.21E-6
SEIS5	0.51-0.71	5.10E-7
SEIS6	0.71-1.02	1.44E-7

Regulatory Guide 1.200, Rev. 2 (Table 7)		NMP2 Assessment
Element	**Technical Characteristics and Attributes**	
Seismic Fragility Analysis	1. Seismic fragility estimate a. plant-specific b. realistic c. includes all systems that participate in accident sequences included in the seismic-PRA systems model d. basis for screening of high capacity components is fully described 2. Seismic fragility evaluation performed for critical SSCs based on a. review of plant design documents b. earthquake experience data c. fragility test data d. generic qualification test data (use is justified) e. walkdowns 3. walkdowns focus on a. anchorage b. lateral seismic support c. potential systems interactions	Systems and equipment modeled in the PRA as well as the structures that house this equipment were identified and considered in developing the equipment list for the seismic margins assessment. Also, a relay chatter evaluation was performed to identify those relays that could potentially affect mitigating equipment. Structures, systems, and components identified were evaluated for seismic capabilities including seismic qualification, analysis, and test information that would support screening. Calculations were performed as necessary to support screening. The strategy developed for the seismic margin assessment and PRA development included the following: 1. The seismic margins assessment used a 0.5g HCLPF as the screening level instead of 0.3 required by Generic Letter 88-20. This was to ensure that the screening fragility used in the PRA as a direct contributor to CDF (COMP1) would not be too conservative. 2. Consistent with other seismic PRAs, loss of feedwater, main condenser and their support systems is incorporated within the loss of offsite power fragility (COMP3). This is a reasonable assumption since offsite power has been assessed to be the weak link and this is based on actual earthquake experience. The seismic margins evaluation methodology is based on the following including detailed walkdowns: • EPRI NP-6041, "A Methodology for Assessment of Nuclear Power Plant Seismic Margin," Revision 1, August 1991. • SQUG, "Generic Implementation Procedure (GIP) For Seismic Verification of Nuclear Plant Equipment," Revision 2 Corrected, February 14, 1992. • EPRI NP-5223, "Generic Seismic Ruggedness of Power Plant Equipment," Rev 1, February 1991. • EPRI NP-7147, "Seismic Ruggedness of Relays," February 1991. • EPRI NP-7146, "Development of In-Cabinet Amplified Response Spectrum for Electrical Cabinets," December 1990. • EPRI NP-7148, "Procedure for Evaluating Nuclear Power Plant Relay Seismic Functionality," December 1990. As a result of the seismic margins evaluation of structures and equipment, the only component that did not meet the 0.5g HCLPF screening was the nitrogen makeup supply (COMP2). Also, it was noted during the evaluation that some components, including certain relays, had small margins above the 0.5g HCLPF screening value. Thus, the conservatism in the model with regard to assigning the screening HCLPF (COMP1) to core damage may not be significant. Additional more detailed fragility analysis would be required to make this determination.

Regulatory Guide 1.200, Rev. 2 (Table 7)		NMP2 Assessment
Element	**Technical Characteristics and Attributes**	
		NMP2 specific references include the following: • "Identification of Structures, Systems & Components," Nine Mile Point Unit 2 IPEEE - Seismic Analysis, NMPC Report SAS-I3U2-1, December 1993. • "Relay Chatter Evaluation," Nine Mile Point Unit 2 IPEEE - Seismic Analysis, NMPC Report SAS-I3U2-2, January 1994. • NMP2 Screening Evaluation Work Sheets (SEWS) signed by the Seismic Review Team, 6/94. • NMPC Document Number STRS 08.000-5000, Rev 0, "NMP2 IPEEE Floor response Spectra," Prepared by Stevenson & Associates. • NMPC Calculation 2-SQ-061, Rev 0, "HCLPF Calculations for IPEEE." • NMPC Document Number STRS 08.000-5001, Rev 0, "NMP2 IPEEE Relay HCLPF Evaluation Report," Prepared by Stevenson & Associates. • NMPC Calculation 2-SQ-061, Rev 0 Disposition 00A, "HCLPF Calculations for IPEEE." ***GAP**: Overall, the analysis is judged to be conservative. The contribution to CDF is still small (4%). The impact to LERF is 35% and as such, it is an important contributor that is dominated by screening fragility. However, this does not impact the proposed amendment.*
Seismic Plant Response Analysis	1. The seismic PRA models include a. seismic-caused initiating events b. seismically induced SSC failures c. nonseismically induced unavailabilities, d. other significant failures (including human errors) that can lead to CDF or LERF 2. The seismic PRA models a. adapted to incorporate seismic-analysis aspects that are different from corresponding aspects found in the at-power, internal events PRA model b. reflects the as-built and as-operated plant being	The internal events PRA model is used to represent the plant response for seismic initiating events. The transient model is used as well as its transfer to medium LOCA (stuck open SRV) and station blackout models. The model is based on the following: • The seismic initiating basic events (SEIS1 through SEIS6) are included as initiating events in the transient event tree model top logic. • The screening fragility (COMP1) is incorporated into the AC and DC power models, including recovery models to ensure that this fragility goes directly to core damage. • The nitrogen fragility (COMP2) is incorporated into the nitrogen system model as a failure mode. • The offsite power fragility (COMP3) is incorporated into the normal offsite AC power model, including recovery.

Regulatory Guide 1.200, Rev. 2 (Table 7)		NMP2 Assessment
Element	**Technical Characteristics and Attributes**	
	analyzed 3. Quantification of CDF and LERF integrates a. the seismic hazard b. the seismic fragilities c. the systems analysis	• Key human actions were evaluated, including recovery of seismic induced failures. • Operator action to depressurize the reactor, given loss of RCIC and HPCS is an important event (ZOD05). It was assumed for transients that the operators inhibited ADS (automatic depressurization) and then, had to manually open the safety relief valves when level reached top of active fuel. The reliability of ADS and injection systems is sufficiently high such that if the operators failed to disable ADS, core damage frequency would not change significantly. In fact, it is assumed that this treatment is as conservative for seismic events as it is for transients. The operator failure probability used for emergency depressurization was increased in the seismic model relative to a general transient. • Long term alignment of RHR to suppression pool cooling is explicitly modeled (ZOH01). This was considered to be a very reliable operator action for non seismic events due to the significant time available, limited actions required, and redundant cues available to the operators in the EOPs. The total unavailability of RHR Trains A and B with all support systems available has a higher failure probability than ZOH01, which has the equivalent impact as the operator failure. This value is assumed to reasonably envelop operator errors even for seismic events. • The containment isolation (IS) model includes an operator action to isolate outside motor operated valves, given a station blackout. The operator failure probability is set to 1.0 for the case where COMP1 fails. • Operator action to initiate ECCS given that signals fail (ZME01) is conservatively set to failure for seismic initiating events. ***GAP**: A more detailed HRA evaluation should be completed for future updates. This is unlikely to impact the proposed amendment as demonstrated by the fire sensitivity analysis of operator actions related to events outside the control room.*