UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	Docket Nos. 52-012-COL
	)	52-013-COL
STP NUCLEAR OPERATING COMPANY	)	
	)	
(South Texas Project Units 3 and 4)	)	January 22, 2010

APPLICANT'S ANSWER OPPOSING NEW AND REVISED CONTENTIONS REGARDING ENVIRONMENTAL REPORT SECTION 7.5S

I. INTRODUCTION

In accordance with 10 C.F.R. § 2.309(h), STP Nuclear Operating Company ("STPNOC"), applicant in the above-captioned proceeding, hereby submits this Answer opposing the new and revised contentions proffered by the Intervenors related to the impacts of accidents at one unit on co-located units, as discussed in Environmental Report ("ER") Section 7.5S.

In the December 22, 2009 "Intervenors' Contentions Regarding Applicant's Proposed Revision to Environmental Report Section 7.5S and Request for Hearing" ("Request"), the Intervenors sought admission of four new contentions related to STPNOC's addition of a new ER Section 7.5S. Additionally, in the December 14, 2009 "Intervenors' Response to Applicant's Motion to Dismiss Contention 21 as Moot" ("Intervenors' Answer"), the Intervenors requested that the Atomic Safety and Licensing Board ("Board") revise admitted Contention 21 to include Intervenors' allegations related to ER Section 7.5S.

As demonstrated below, the four new contentions and the proposed revisions to Contention 21 do not satisfy the contention admissibility requirements specified in 10 C.F.R. § 2.309(f), and therefore should be rejected.

II. PROCEDURAL BACKGROUND

The Board admitted Contention 21 on August 27, 2009.[1] Contention 21 is a contention of omission stating that the ER failed to analyze the environmental impacts of a radiological incident at one of the STP units on the co-located units.[2]

On November 11, 2009, STPNOC submitted a notification to the Board regarding Contention 21.[3] That notification informed the Board that STPNOC submitted a letter to the Nuclear Regulatory Commission ("NRC") with revisions to the ER for STP Units 3 and 4 on November 10, 2009.[4] STPNOC created a new ER Section 7.5S that evaluates the impacts of an accident at one of the new or existing units at the STP site on the other units at the site.[5] On November 30, 2009, STPNOC requested that the Board dismiss Contention 21 as moot based on the new ER Section 7.5S.[6] This request was opposed by the Intervenors, who requested that the Board revise Contention 21.[7] Thereafter, on December 22, 2009, the Intervenors filed the four new contentions related to ER Section 7.5S.

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1 *South Texas Project Nuclear Operating Co.* (South Texas Project Units 3 and 4), LBP-09-21, 70 NRC __, slip op. at 36-39 (Aug. 27, 2009).

2 *Id.* at 38.

3 Letter from S. Burdick, Counsel for STPNOC, to the Board, Notification of Filing Related to Contention 21 (Nov. 11, 2009) ("Notification Letter").

4 Attachment to Notification Letter, Letter from S. Head, STPNOC, to NRC, Proposed Revision to Environmental Report (Nov. 10, 2009) ("ER Letter").

5 ER Letter, Attachment, at 1-9.

6 *See* Applicant's Motion to Dismiss Contention 21 as Moot, at 1, 5 (Nov. 30, 2009).

7 Intervenors' Answer at 1-2, 5.

III. LEGAL STANDARDS

A petitioner must show that a late-filed contention meets the contention admissibility requirements of 10 C.F.R. § 2.309(f)(1)(i)-(vi).[8] These requirements are discussed in detail in STPNOC's May 18, 2009 Answer opposing the Petition, and a briefer discussion of the important contention admissibility requirements is set forth below.

Under 10 C.F.R. § 2.309(f)(1), a hearing request "must set forth with particularity the contentions sought to be raised." In addition, that section specifies that each contention must: (1) provide a specific statement of the legal or factual issue sought to be raised; (2) provide a brief explanation of the basis for the contention; (3) demonstrate that the issue raised is within the scope of the proceeding; (4) demonstrate that the issue raised is material to the findings the NRC must make to support the action that is involved in the proceeding; (5) provide a concise statement of the alleged facts or expert opinions, including references to specific sources and documents that support the petitioner's position and upon which the petitioner intends to rely; and (6) provide sufficient information to show that a genuine dispute exists with regard to a material issue of law or fact.[9]

The purpose of these six criteria is to "focus litigation on concrete issues and result in a clearer and more focused record for decision."[10] The Commission has stated that it "should not have to expend resources to support the hearing process unless there is an issue that is appropriate for, and susceptible to, resolution in an NRC hearing."[11]

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[8] *See Sacramento Mun. Util. Dist.* (Rancho Seco Nuclear Generating Station), CLI-93-12, 37 NRC 355, 362-63 (1993); *see also Crow Butte Res., Inc.* (License Renewal for In Situ Leach Facility, Crawford, Nebraska), CLI-09-9, 69 NRC 331, 364 (2009) (stating that the timeliness of the late-filed contention need not be evaluated because the contention did not satisfy the contention admissibility requirements of 10 C.F.R. § 2.309(f)(1)).

[9] *See* 10 C.F.R. § 2.309(f)(1)(i)-(vi).

[10] Final Rule, Changes to Adjudicatory Process, 69 Fed. Reg. 2182, 2202 (Jan. 14, 2004).

[11] *Id.*

The Commission's rules on contention admissibility are "strict by design."[12] The rules were "toughened . . . in 1989 because in prior years 'licensing boards had admitted and litigated numerous contentions that appeared to be based on little more than speculation.'"[13] As the Commission has stated:

> Nor does our practice permit "notice pleading," with details to be filled in later. Instead, we require parties to come forward at the outset with sufficiently detailed grievances to allow the adjudicator to conclude that genuine disputes exist justifying a commitment of adjudicatory resources to resolve them.[14]

The failure to comply with any one of the six admissibility criteria is grounds for rejecting a proposed contention.[15]

IV. GENERIC OBJECTIONS TO THE NEW AND REVISED CONTENTIONS

As discussed in Subsections A and B below, all of the proposed revisions to Contention 21 and the new contentions pertain to matters that are not material to evaluations under the National Environmental Policy Act ("NEPA"). Therefore, all of the proposed revisions and the new contentions should be rejected in accordance with 10 C.F.R. § 2.309(f)(1)(iv).

Additionally, as discussed in Subsection C below, many of the proposed revisions to Contention 21 and the new contentions argue that an accident at one unit could adversely affect a co-located unit, but do not contest STPNOC's evaluation of the environmental impacts of a scenario involving simultaneous severe accidents at all four units. Therefore, the proposed new

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12 *Dominion Nuclear Conn., Inc.* (Millstone Nuclear Power Station, Units 2 & 3), CLI-01-24, 54 NRC 349, 358 (2001) (citing *Duke Energy Corp.* (Oconee Nuclear Station, Units 1, 2, & 3), CLI-99-11, 49 NRC 328, 334 (1999)).

13 *Millstone*, CLI-01-24, 54 NRC at 358 (citing *Oconee*, CLI-99-11, 49 NRC at 334).

14 *N. Atl. Energy Serv. Corp.* (Seabrook Station, Unit 1), CLI-99-6, 49 NRC 201, 219 (1999).

15 *See* Final Rule, Changes to Adjudicatory Process, 69 Fed. Reg. at 2221; *see also Private Fuel Storage, L.L.C.* (Independent Spent Fuel Storage Installation), CLI-99-10, 49 NRC 318, 325 (1999).

and revised contentions do not raise a genuine dispute of material fact and should be rejected in accordance with 10 C.F.R. § 2.309(f)(1)(vi).

A. NEPA Does Not Require Evaluation of Remote and Speculative Events

NEPA requires that federal agencies, such as the NRC, prepare an Environmental Impact Statement ("EIS") in conjunction with "every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment."[16] An EIS must discuss "the environmental impact of the proposed action."[17]

As a general matter, NEPA imposes procedural restraints on agencies, requiring them to take a "hard look" at the environmental impacts of a proposed action.[18] This "hard look," however, is subject to a "rule of reason."[19] This means that an "agency's environmental review, rather than addressing every impact that could possibly result, need only account for those that have some likelihood of occurring or are reasonably foreseeable."[20] Consideration of "remote and speculative" or "inconsequentially small" impacts is not required.[21] As the Commission has explained, "NEPA also does not call for certainty or precision, but an *estimate* of anticipated (not unduly speculative) impacts."[22]

Consistent with these requirements, the Commission has explained:

> NEPA's twin goals are to inform the agency and the public about the environmental effects of a project. At NRC licensing hearings,

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16 42 U.S.C. § 4332(C).

17 *Id.* § 4332(C)(i)-(ii).

18 *See La. Energy Servs., L.P.* (Claiborne Enrichment Center), CLI-98-3, 47 NRC 77, 87-88 (1998); *see also La. Energy Servs., L.P.* (National Enrichment Facility), CLI-05-28, 62 NRC 721, 726 (2005) (citation omitted).

19 *La. Energy Servs., L.P.* (National Enrichment Facility), LBP-06-8, 63 NRC 241, 258 (2006) (citing *Long Island Lighting Co.* (Shoreham Nuclear Power Station), ALAB-156, 6 AEC 831, 836 (1973)).

20 *National Enrichment*, LBP-06-8, 63 NRC at 258-59 (citing *Shoreham*, ALAB-156, 6 AEC at 836).

21 *See Vt. Yankee Nuclear Power Corp.* (Vermont Yankee Nuclear Power Station), ALAB-919, 30 NRC 29, 44 (1989) (citing *Limerick Ecology Action v. NRC*, 869 F.2d 719, 739 (3d Cir. 1989)).

22 *La. Energy Servs. L.P.* (National Enrichment Facility), CLI-05-20, 62 NRC 523, 536 (2005).

> petitioners may raise contentions seeking correction of significant inaccuracies and omissions in the ER. Our boards do not sit to "flyspeck" environmental documents or to add details or nuances. If the ER (or the EIS) on its face "comes to grips with all important considerations" nothing more need be done.[23]

All of the new and revised contentions submitted by the Intervenors raise environmental issues under NEPA. As discussed below, these contentions seek more than is required by NEPA and attempt to "flyspeck" the ER. These contentions should be rejected.

Severe accident evaluations—like all evaluations performed pursuant to NEPA—are subject to a "rule of reason."[24] In accordance with this rule of reason, for the first ten years after the passage of NEPA, the Commission held that consideration of severe accidents (which were then referred to as "Class 9 accidents") was unnecessary on the grounds that such accidents in traditional light water reactors were "remote and speculative."[25]

Following the accident at Three Mile Island Unit 2, the Commission issued a Statement of Interim Policy on Class 9 accidents, which directed the NRC to evaluate the environmental impacts of Class 9 accidents in future EISs for nuclear power reactors.[26] The Statement of Interim Policy indicated that although severe accidents are "sufficiently remote in probability that the environmental risk is extremely low," the NRC would nonetheless consider such accidents in its NEPA reviews.[27]

Even after the Commission issued the Statement of Interim Policy, the courts continued to take the position that *NEPA did not require* consideration of Class Nine accidents, because

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[23] *Sys. Energy Res., Inc.* (Early Site Permit for Grand Gulf ESP Site), CLI-05-4, 61 NRC 10, 13 (2005) (footnotes omitted); *see also Exelon Generation Co., LLC* (Early Site Permit for Clinton ESP Site), CLI-05-29, 62 NRC 801, 811 (2005).

[24] *See Natural Res. Def. Council v. Morton*, 458 F.2d 827, 834 (D.C. Cir. 1972).

[25] *See, e.g.*, *Carolina Envtl. Study Group v. United States*, 510 F.2d 796, 799–800 (D.C. Cir. 1975).

[26] Statement of Interim Policy, Nuclear Power Plant Accident Considerations Under the National Environmental Policy Act of 1969, 45 Fed. Reg. 40,101 (June 13, 1980).

[27] *Id.* at 40,102.

such accidents are remote and speculative. In particular, in *San Luis Obispo Mothers for Peace v. NRC*,[28] the Court stated:

> [T]he Commission did not conclude in its Statement of Interim Policy that its original assumption regarding Class Nine accidents was scientifically incorrect. Rather, it recognized the need for renewed study of the issue. The clear import of the Commission's statement is that, until such time as its research yields a contrary result, the Commission continues to regard Class Nine accidents as highly improbable events. . . .
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> NEPA, therefore, does not require the consideration of Class Nine accidents in future EISs. . . . The approach adopted in the Statement of Interim Policy – to include discussion of such accidents in future EISs – was a discretionary policy choice.

Thus, the Commission as a matter of discretion has directed that EISs evaluate the environmental impacts of severe accidents at the reactor being licensed, even though such evaluations are not required by NEPA. In doing so, the Commission has made clear that "low probability is the key to applying NEPA's rule of reason test to contentions that allege that a specified accident scenario presents a significant environmental impact that must be evaluated."[29] Accordingly, the Commission stated that "[i]f the accident sought to be considered is sufficiently unlikely that it can be characterized fairly as remote and speculative, then consideration under NEPA is not required as a matter of law."[30]

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[28] 751 F.2d 1287, 1301 (D.C. Cir. 1984), *aff'd on rehearing en banc*, 789 F.2d 26 (D.C. Cir. 1986), *cert. denied* 479 U.S. 923 (1986) (footnote omitted). *Cf. Limerick Ecology Action v. NRC*, 869 F.2d 719, 739-41 (3d Cir. 1989), where the NRC took the position before the court that it was not required to consider severe accident mitigation alternatives because severe accidents are remote and speculative. The court rejected that argument, because the NRC had not based its decision in the proceeding on that position.

[29] *Vt. Yankee Nuclear Power Corp.* (Vermont Yankee Nuclear Power Station), CLI-90-7, 32 NRC 129, 131 (1990).

[30] *Vt. Yankee Nuclear Power Corp.* (Vermont Yankee Nuclear Power Station), CLI-90-4, 31 NRC 333, 335 (1990).

B. ER Section 7.5S Demonstrates that an Accident that Could Impact a Co-Located Unit Is a Remote and Speculative Event

All of the proposed revisions to Contention 21 and all of the new contentions are predicated upon an accident at one STP unit that adversely impacts other units at the STP site. As discussed in ER Section 7.5S, the probability of occurrence of an accident at one unit that could potentially affect a co-located unit is extremely small. Such an accident would involve both core damage and a large release of radioactivity during an accident.[31] As indicated in ER Section 7.5S.3, the Large Release Frequency ("LRF") for the Advanced Boiling Water Reactor ("ABWR") to be used at STP Units 3 and 4 is about 2.2×10^{-8} per year, and the Large Early Release Frequency ("LERF") for STP Units 1 and 2 is about 6.1×10^{-7} per year.[32] In other words, the frequency of such accidents is less than one in a million years. The Intervenors have not contested these values.

NEPA does not require an evaluation of the impacts of an accident at one STP unit on a co-located unit, given the low probability of such an event. As was recently held by the licensing board in the *Calvert Cliffs* combined license proceeding, an environmental report for a new nuclear plant does not need to evaluate the impacts of external events that have a low probability of occurrence.[33] The board stated that, under NEPA's rule of reason, a probability of 10^{-6} per year is the "threshold above which accident scenarios must be evaluated for NEPA consideration."[34]

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[31] Most core damage events do not result in large releases of radioactivity. A large release would occur only if containment integrity is not maintained.

[32] ER Letter, Attachment, at 4-5.

[33] *Calvert Cliffs 3 Nuclear Project, LLC* (Combined License Application for Calvert Cliffs Unit 3), LBP-09-04, 69 NRC 208, 209 (2009).

[34] *Id.*

It is undisputed that the probability of a large radiological release from an STP unit is well below this threshold. As a result, an accident that could affect a co-located unit at the STP site is remote and speculative and need not be considered under NEPA. Because the Intervenors' proposed revisions to Contention 21 and its new contentions are predicated on events that do not need to be evaluated under NEPA, the proposed revisions and new contentions all raise issues that are not material to this proceeding and accordingly should be rejected pursuant to 10 C.F.R. § 2.309(f)(1)(iv).

C. The Proposed Revisions and New Contentions Do Not Raise a Genuine Dispute of Material Fact Regarding the Environmental Impacts of Simultaneous Severe Accidents at All Four STP Units

ER Section 7.5S includes two evaluations related to the impacts of an accident at one unit on co-located units at the STP site. First, ER Sections 7.5S.2 and 7.5S.3 evaluate whether accidents at one STP unit could adversely impact the safe shutdown of the other units, and demonstrate that they would not. Second, ER Section 7.5S.6 evaluates the environmental impacts of a hypothetical event involving an accident at one STP unit that causes simultaneous severe accidents in the other three STP units. The evaluation in ER Section 7.5S.6 demonstrates that the risk-based environmental impacts from simultaneous severe accidents in all four STP units would be SMALL, given the low probability of such an event. In particular, ER Section 7.5S.6 states:

> Furthermore, even if it is arbitrarily postulated that a severe accident in the affected unit could cause a simultaneous severe accident in each of the unaffected units, the cumulative environmental impacts would still be SMALL. In such a scenario, the releases of radioactivity from all four units would be approximately four times the release from an individual unit. However, even if the environmental impacts (risks) discussed in Section 7.2.4 for an accident originating in one of the ABWR units were to be multiplied by a factor of four, the environmental risks would still be insignificant. For example, the cumulative risk from all four units would be about 0.017 person-rem/year (i.e., 4 x

> 0.0043 person-rem per reactor year), which is more than a factor of ten less than the cumulative dose risk from normal operation (about 0.5 person-rem per reactor year). Furthermore, the risk of cancer from such an accident scenario would be about 0.0044% of the background risk (i.e., four times 0.0011% of the background risk). This value is well below the 0.1% value specified in the Commission's Safety Goal Policy Statement.
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> As discussed in Section 7.5S.3, the LERF for Units 1 and 2 is approximately 30 times greater than the LRF for Units 3 and 4. However, even if the risk-based values in the previous paragraph were to be multiplied by a factor of 30, the resulting dose risk would be equivalent to the cumulative dose risk from normal operation and the resulting cancer risk would be equivalent to the Commission's Safety Goal. Therefore, the environmental impact from such a scenario would be SMALL.

A number of the Intervenors' proposed revisions to Contention 21 and their new contentions take issue with the evaluations in ER Sections 7.5S.2 and 7.5S.3. In particular, Contention CL-1 (including parts A through D) and all of the proposed revisions to Contention 21 contest one or more elements in ER Sections 7.5S.2 and 7.5S.3. However, the Intervenors have not contested the evaluation in ER Section 7.5S.6 that is quoted above.

In light of the undisputed evaluation in ER Section 7.5S.6, the Intervenors' contentions related to ER Sections 7.5S.2 and 7.5S.3 do not raise a genuine dispute of fact. Even if all of the allegations in Contention CL-1 and the proposed revisions to Contention 21 were assumed to be factually correct (*i.e.*, even if it is assumed that an accident at one unit could adversely impact the other units), the Intervenors have not contested the evaluation in ER Section 7.5S.6 which demonstrates that the environmental impacts from such a scenario would be SMALL. Accordingly, Contention CL-1 and the proposed revisions to Contention 21 should be rejected in

accordance with 10 C.F.R. § 2.309(f)(1)(iv) and (vi) because admission of those contentions would not make a difference in the conclusions in ER Section 7.5S.[35]

D. Conclusion

For the reasons discussed above, all of the Intervenors' new contentions and proposed revisions to Contention 21 should be rejected. Furthermore, as discussed in the next section, each of the individual contentions and proposed revisions is deficient on other grounds as well.

V. SPECIFIC OBJECTIONS TO THE NEW AND REVISED CONTENTIONS

A. Contention CL-1

Contention CL-1 states:

> The STPNOC evaluation of the possible impacts of a severe accident at one of the STP units on the other STP units is inadequate.[36]

The Intervenors rely upon Dr. Edwin Lyman as support for this contention.[37] This contention is separated into four parts, each of which is addressed separately below.

1. Contention CL-1, Part A, Severe Accident Warning Time

Part A of Contention CL-1 states:

> The Amended ER § 7.5S.3 states that the time from general emergency warning until the first release of radiation was of sufficient duration in all ten accident scenarios to put unaffected units into stable long term decay heat removal condition. However, in Applicant's accident scenario eight the release occurred prior to bringing unaffected units into stable long-term decay heat removal condition. Therefore the proposed amendment to the ER is not adequately substantiated.[38]

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[35] As the Commission has stated, "[t]he dispute at issue is 'material' if its resolution would 'make a difference in the outcome of the licensing proceeding.'" *See Oconee*, CLI-99-11, 49 NRC at 333-34 (citing Final Rule, Rules of Practice for Domestic Licensing Proceedings – Procedural Changes in the Hearing Process, 54 Fed. Reg. at 33,172).

[36] Request at 3.

[37] *Id.*

[38] *Id.* at 3-4.

The Intervenors rely upon entries in the ABWR Design Control Document ("DCD") Tier 2 Table 19E.3-6, Event Release Parameters, to conclude that for Case 8 "the radiological release to the environment commences after 2 hours, or 1.2 hours after the declaration of a general emergency."[39]

This issue raised by the Intervenors regarding accident case 8 is not material under NEPA. As discussed in ER Table 7.2-1, Case 8 has a frequency of 4.05E-10 per year (*i.e.*, about twice in ten billion years).[40] By any reasonable definition, such an event is remote and speculative and need not be considered under NEPA.[41]

In any event, as discussed in Section IV.C above, ER Section 7.5S.6 provides a hypothetical evaluation that assumes that all of the STP units experience simultaneous severe accidents and demonstrates that the environmental impact is SMALL. Therefore, even if it were assumed that Part A of Contention CL-1 is correct and that the co-located units could not be safely shutdown, it would not make a difference to the conclusions provided in ER Section 7.5S.6. In other words, the evaluation in Section 7.5S.6 encompasses the Intervenors' arguments regarding Case 8 and the ability to shut down a co-located unit. As the Commission has stated, "[t]he dispute at issue is 'material' if its resolution would 'make a difference in the outcome of

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[39] *Id.* at 4-5. ER Section 7.5S uses information for the minimum time between damage and release from ABWR DCD Tier 2 Table 19E.2-16, Summary of Critical Parameters for Severe Accident Sequences. For accident sequence NSRC-PF-R-N, the Time of Vessel Failure is at 5.6 hours, and the Fission Product Release Time is at 8.6 hours. (STP Attachment 1). This was the shortest release time (3 hours) calculated for the severe accident scenarios quantified in the ABWR Probabilistic Risk Assessment ("PRA"), and provides the basis for the conclusion in ER Section 7.5S that "[t]he time increment from general emergency warning time until the first release of radioactivity to the environment for all ten accident sequences is greater than the time required to put an unaffected unit into a stable long-term decay heat removal condition." ER Letter, Attachment, at 4. DCD Tier 2 Table 19E.2-16 is the correct source for ER Section 7.5S as it reflects data generated by the MAAP code for the vessel and containment responses under severe accident conditions. DCD Tier 2 Table 19E.3-6 reflects input parameters used for other analytical purposes. (STP Attachment 2). However, as discussed below, any dispute between these time values is inconsequential because this contention fails for other reasons.

[40] ER at 7.2-9 (Rev. 3, 2009), *available at* ADAMS Accession No. ML092931582.

[41] *See Calvert Cliffs*, LBP-09-04, 69 NRC at 208-09.

the licensing proceeding.'"[42] Therefore, because the Intervenors' arguments would not change the conclusions in ER Section 7.5S.6, they are not material, contrary to 10 C.F.R. § 2.309(f)(1)(iv) and (vi).

2. Contention CL-1, Part B, Severe Accidents During Shutdown

Part B of Contention CL-1 states: "The proposed amendments to the ER do not address the radiological impact of a severe accident at an STP unit during shutdown, when the primary containment head is removed, on the other STP units."[43] In particular, the Intervenors are contending that "the ABWR large release frequency (LRF) does not contain contributions from severe accidents during low power or shutdown operations," which the Intervenors allege "are significant and sometimes dominant contributors to LRF."[44] As discussed below, the Intervenors' arguments are untimely, constitute an impermissible challenge to the finality of the ABWR, and do not raise a genuine dispute of material fact.

The Intervenors' argument is untimely and should be rejected for failure to satisfy or even address the factors identified in 10 C.F.R. § 2.309(c) and (f)(2). In this regard, the evaluation in ER Section 7.5S.3 of an accident in Unit 3 or 4 is based upon the severe accident scenarios identified in ER Section 7.2, which was not changed when STPNOC submitted the revision to add ER Section 7.5S. If the Intervenors desire to contend that the ER should evaluate severe accidents at Units 3 and 4 involving shutdown conditions, then they should have raised a challenge to ER Section 7.2 in response to the notice of hearing for this proceeding. The Intervenors' attempt to challenge these accidents now is untimely, contrary to 10 C.F.R. § 2.309(c) and (f)(2).

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[42] *See Oconee*, CLI-99-11, 49 NRC at 333-34 (citing Final Rule, Rules of Practice for Domestic Licensing Proceedings – Procedural Changes in the Hearing Process, 54 Fed. Reg. at 33,172).

[43] Request at 5.

[44] *Id.*

Additionally, the Intervenors' arguments constitute an impermissible challenge to the finality of the ABWR design certification. The probability of accidents during shutdown conditions was evaluated for the ABWR design certification and shown to be low. For example, ABWR DCD Tier 2 Section 19Q.12.5 (STP Attachment 3) explains:

> The ABWR has been evaluated for risks associated with shutdown conditions and for all postulated events, the risk has been determined to be low. Multiple means of removing decay heat and supplying inventory makeup have been identified that along with appropriate Technical Specifications and outage procedures result in acceptably low shutdown risk levels for the ABWR.

Similarly, Section 19.1.3.4 of the Final Safety Evaluation Report ("FSER") for the ABWR states:

> The staff concludes, based on previous shutdown analyses (both international and U.S. operating reactors) and the ABWR Shutdown Risk Evaluation, that the chances of a core damage event occurring when in Modes 3, 4, or 5 [shutdown or refueling] is probably on the same order of magnitude as that of internal events occurring in Modes 1 and 2 [startup or operation].[45]

Therefore, the ABWR DCD evaluated the accidents during shutdown conditions and determined that the risks are low, and the NRC Staff has concluded that the risks are on the same order of magnitude as those during operations.[46] These conclusions have finality in accordance with 10 C.F.R. Part 52, Appendix A, Section VI.B and are not subject to challenge in this proceeding.

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[45] NUREG-1503, Final Safety Evaluation Report Related to the Certification of the Advance Boiling Water Reactor Design, Main Report, at 19-29 (July 1994) (STP Attachment 4).

[46] The Intervenors also quote from the ABWR FSER, which states: "NUREG-1449 stated that BWR secondary containments were judged unlikely to prevent an early release following initiation of boiling with an open RCS or during potential severe-core-damage scenarios. This is also the case for the ABWR." Request at 5-6. The Intervenors ignore the discussion in the FSER that explains that the concerns in NUREG-1449 have been addressed. Specifically, FSER Section 19.3.3.3 discusses the capabilities of the ABWR containment design for low power/shutdown operation and concludes: "Based on the conclusions reached in NUREG-1449 and the improvements, beyond that of operating BWRs, provided in the ABWR design, the staff concludes that additional requirements are not necessary for the primary containment." NUREG-1503, at 19-81 (STP Attachment 4). Thus, the Intervenors' quotation from the FSER does not demonstrate a genuine dispute of a material fact, contrary to 10 C.F.R. § 2.309(f)(1)(vi).

Given those conclusions, there is no reason for ER Section 7.5S to include a discussion of risks during shutdown conditions. In any event, even if ER Section 7.5S had included such a discussion, it would not have affected the results. As discussed in ER Sections 7.5S.5 and 7.5S.6, the cost impacts and dose risks from an accident in one of the ABWRs could be increased by one to two orders of magnitude without affecting the results of those evaluations. Therefore, even if the risk of accidents at the ABWR were conservatively increased by a factor of ten to account for the risk of accidents during shutdown and low power conditions, there would be no impact upon the conclusions in those sections. Thus, this contention does not establish a genuine dispute of material fact and should be rejected in accordance with 10 C.F.R. § 2.309(f)(1)(vi).[47]

In summary, given the low risks posed by low power and shutdown conditions in an ABWR, the conclusions in the ER would not be affected if it were to include an explicit discussion of this issue. Therefore, this contention does not raise a material issue. In this regard,[48] the licensing boards do not sit to "flyspeck" ERs and EISs or to "add details or nuances."[49] Therefore, this part of Contention CL-1 should be rejected.

3. Contention CL-1, Part C, External Events

Part C of Contention CL-1 states:

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[47] The Intervenors base this contention on Request for Additional Information ("RAI") 19-3 from the NRC Staff. Request at 5 n.5. RAI 19-3 requests that STPNOC provide information on the impacts of low power and shutdown scenarios; it does not state that the ABWR is deficient in this respect. (STP Attachment 5). This reliance on the Staff's RAI as a basis for this contention runs afoul of long-standing Commission precedent. The Commission has held that "petitioners must do more than 'rest on [the] mere existence' of RAIs as a basis for their contention." *Oconee*, CLI-99-11, 49 NRC at 336 (quoting *Baltimore Gas & Elec. Co.* (Calvert Cliffs Nuclear Power Plant, Units 1 and 2), CLI-98-25, 48 NRC 325, 350 (1998)). Instead, a petitioner must provide an "analysis, discussion, or information of their own on any of the issues raised in the RAIs." *Oconee*, CLI-99-11, 49 NRC at 337. The Intervenors have not done this.

[48] The ABWR design certification does not include a PRA for low power and shutdown conditions, and such a PRA does not need to be conducted under 10 C.F.R. § 50.71(h)(1) until fuel load at the earliest. Therefore, at this stage of the project, only qualitative analyses of the risks posed by low power and shutdown conditions exist.

[49] *Grand Gulf*, CLI-05-4, 61 NRC at 13 (footnotes omitted); *see also Exelon Generation Co., LLC* (Early Site Permit for Clinton ESP Site), CLI-05-29, 62 NRC 801, 811 (2005).

> The amendments to the ER fail to evaluate the impact of a severe accident at one STP unit on the other units when the initiating event of the accident is an external event such as an earthquake, that could result in common-cause failures of systems at one or more of the other units, potentially extending the time necessary for operators to put the units into stable long-term decay heat removal configurations.[50]

This allegation mischaracterizes the ER. ER Section 7.5S.3 addresses external events (which include seismic events). Specifically, this section states: "Externally initiated events, and their associated small contribution to risk, are described in FSAR Section 19.4 and 19.6, which in turn incorporate by reference the associated sections of the ABWR DCD."[51] Additionally, ER Section 7.5S.3 quotes the conclusion in the ABWR FSER stating that the external events have low CDFs and the ABWR design meets the Commission's safety goals.[52] Therefore, the Intervenors' argument that "Section 7.5S of the ER only considers severe accidents associated with internally initiated events" is incorrect and mischaracterizes ER Section 7.5S.[53] Therefore, this contention does not demonstrate a genuine dispute of a material fact, contrary to 10 C.F.R. § 2.309(f)(1)(vi).[54]

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50 Request at 6.

51 ER Letter, Attachment, at 4.

52 NUREG-1503, at 19-1 (STP Attachment 4).

53 The ABWR design certification does not include a PRA for seismic events, and such a PRA does not need to be conducted under 10 C.F.R. § 50.71(h)(1) until fuel load at the earliest. Therefore, at this stage of the project, only qualitative analyses of the risks posed by seismic events exist.

54 The Intervenors quote from page 20-88 of the ABWR FSER, which states that the seismic risk from the ABWR could be one to two orders of magnitude greater than the risk from internal events. However, the Intervenors selectively quoted from the FSER - - the remainder of that page states that "the value for the final ABWR design would be somewhat less since these estimates do not account for plant improvements incorporated in the design subsequent to the original PRA analysis, including upgrading the seismic capability of the diesel-driven fire water pump." (STP Attachment 4). Additionally, page 19-1 of the ABWR FSER states: "Although direct comparison of external-event results to these goals is not possible, the ABWR design has significant margins above the design bases for seismic, fire, and internal flood-initiating events and, where computed, has low estimated core damage frequencies from these bounding analyses. The staff believes that the ABWR design meets the Commission's safety goals." (STP Attachment 4). Furthermore, the STP site is in a region of low seismicity (the safe shutdown earthquake (SSE) for the STP site is less than 0.1g, but the ABWR is designed for a SSE of 0.3g). FSAR at 2.0-8 (Rev. 3, 2009), *available at* ADAMS Accession No. ML092931238. As page 19-8 of the ABWR FSER (STP Attachment 4) notes:

In any event, as discussed in Section IV.C above, ER Section 7.5S.6 provides a hypothetical evaluation which assumes that all of the STP units experience simultaneous severe accidents. Therefore, even if it were assumed that Part C of Contention CL-1 is correct and that the co-located units could not be safely shutdown in the event of an accident caused by a seismic event, it would not make a difference to the conclusions provided in ER Section 7.5S.6. In other words, the evaluation in Section 7.5S.6 encompasses the Intervenors' arguments regarding external events and their impact on a co-located unit. Therefore, the Intervenors' arguments are not material, contrary to 10 C.F.R. § 2.309(f)(1)(iv).

4. Contention CL-1, Part D, Chain Reaction of Accidents

Part D of Contention CL-1 states that "[t]he amended ER fails to fully evaluate the impact of a chain-reaction that leads to more than one unit experiencing a severe accident."[55] The Intervenors further state that "if the units were indeed coupled in that a severe accident affecting one would likely lead to comparable accidents in one or more of the co-located units, then the combined radiological consequences could have a significant impact on the ABWR severe accident mitigation design alternatives (SAMDA) analysis."[56]

The first part of this argument mischaracterizes ER Section 7.5S. ER Section 7.5S.6 does evaluate the potential for an accident to impact co-located units and concludes that a chain reaction among the STP units is not possible. ER Section 7.5S.6 states:

> The seismic design bases for the ABWR is a 0.3*g* SSE. In simple terms, the ABWR design can be built at any site that has its site-specific spectrum bounded by the design bases spectrum. Such a site might normally have an SSE of 0.2*g* assigned to it. However, the ABWR will be built to the 0.3*g* SSE standard, regardless. This creates an additional explicit seismic robustness at most potential sites east of the Rocky Mountains.

This statement is doubly true for an ABWR located at the STP site.

[55] Request at 7.

[56] *Id.*

> As demonstrated above, a design basis accident or a severe accident at the affected unit would not prevent the unaffected units from safely shutting down. Additionally, all equipment necessary to complete safe shutdown of the unaffected units would be able to operate as designed without any degradation to its functional capabilities for the exposure levels associated with the airborne release from the accidents evaluated. Therefore, the accident scenarios would not result in any incremental environmental impacts attributable to the unaffected units beyond those evaluated in Sections 7.1 and 7.2.[57]

Therefore, ER Section 7.5S.6 concludes that the "chain-reaction" contemplated by the Intervenors would not occur and there would not be any incremental impacts. Based on this conclusion, there is no reason to perform a SAMDA analysis assuming simultaneous accidents at all four units. For this reason, the Intervenors' argument is not material and should be rejected as contrary to 10 C.F.R. § 2.309(f)(1)(iv).

Additionally, for the purpose of performing a bounding environmental impact analysis, ER Section 7.5S.6 nevertheless does postulate that a severe accident in one unit could cause accidents in the other three units. However, this was an arbitrary assumption for the purposes of a bounding analysis of environmental impacts, and the Intervenors have provided no basis for extending this assumption to the SAMDA analysis.

Finally, while the Intervenors claim that a SAMDA analysis should be performed for a scenario involving severe accidents at four units, they do not allege that such an analysis would impact the conclusions of the SAMDA analysis. ER Section 7.3 performs a SAMDA analysis for a single unit experiencing a severe accident, and provides a highest averted cost-risk for one ABWR of $12,500.[58] Multiplying that value by four to account for severe accidents at four units would result in an overall cost-risk for the four units of $50,000. This value is still well below

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[57] ER Letter, Attachment, at 8.

[58] ER at 7.3-5 (Rev. 3, 2009), *available at* ADAMS Accession No. ML092931583.

the lowest cost SAMDA for an ABWR of $100,000.[59] Therefore, even if the Intervenors' contention were accepted, it would have no impact on any of the outcomes of this proceeding.[60] Accordingly, this contention should be rejected because the Intervenors have not demonstrated a genuine dispute of material fact, contrary to 10 C.F.R. § 2.309(f)(1)(vi).

B. Contention CL-2

Contention CL-2 states:

> The Applicant's quantification of the probable replacement power costs in the event of a forced shutdown of nuclear units on the STP site is inadequate and understates the replacement power costs which would be incurred.[61]

The Intervenors rely upon the report from Mr. Clarence L. Johnson for this contention.[62] That report concludes that the replacement power costs "are roughly 3 to 3.8 times the $430 thousand/day cost used by the Applicant."[63] The Intervenors also argue that this evaluation should be based on a forecast of baseline ERCOT market prices.[64] As discussed below, Contention CL-2 should be rejected because the claims made by the Intervenors are untimely and do not demonstrate a genuine dispute of a material fact.

ER Section 7.5S.5 evaluates the economic impacts of a temporary shutdown of a co-located unit due to an accident, including the corresponding replacement power costs, and then

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59 *See* Technical Support Document for the ABWR, MPL No. A90-3230, 25A5680, Table 4 (1995) (STP Attachment 6).

60 The ER does not need to contain a SAMDA evaluation for STP Units 1 and 2, because such an evaluation is outside the scope of this proceeding (which pertains to Units 3 and 4). As discussed in ER Section 7.5S.5, and is unchallenged by the Intervenors, there is no SAMDA for STP Units 3 and 4 that would prevent or mitigate the economic impacts of accidents in Units 1 and 2.

61 Request at 7.

62 *Id.*

63 *Id.*, Attachment, Review of Replacement Power Costs for Unaffected Units at the STP Site, at 4 (Dec. 21, 2009) ("Johnson Report").

64 Request at 7-8.

concludes that there are no corresponding cost effective design changes.[65] The analysis of replacement power costs in ER Section 7.5S.5 uses the NRC-prescribed approach set forth in NUREG/BR-0184, "Final Report, Regulatory Analysis Technical Evaluation Handbook" (Jan. 1997).[66] NUREG/BR-0184 states that typical short-term replacement power costs for a 910 MWe power plant are $310,000 per day.[67] STPNOC scaled this value up to account for the higher power levels of the STP units, and used this value in an equation specified in NUREG/BR-0184 to calculate the monetized impacts of replacement power costs of a severe accident on the other units.[68] The monetized impacts are shown in ER Tables 7.5S-1 and 7.5S-2.[69]

In this regard, ER Section 7.5S.5 utilizes the same approach as the SAMDA analysis in ER Section 7.3, which also used the assumptions in NUREG/BR-0184.[70] Therefore, to the extent that the Intervenors desire to challenge the replacement power costs specified in NUREG/BR-0184, their challenge is untimely—they should have raised such a contention with respect to ER Section 7.3 in response to the notice of hearing of this proceeding. Since the Intervenors have not justified their untimely challenge, this contention should be dismissed pursuant to 10 C.F.R. § 2.309(c) and (f)(2).

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65 ER Letter, Attachment, at 6-7.

66 *Id.*, Attachment, at 7.

67 NUREG/BR-0184, at 5.51 (STP Attachment 7).

68 ER Letter, Attachment, at 6-7, 9. These calculations are similar to those performed in ER Section 7.3 for a severe accident at one unit. *See id.*, Attachment, at 6.

69 *Id.*, Attachment, at 9.

70 ER at 7.3-2 and 7.3-3 (Rev. 3, 2009), *available at* ADAMS Accession No. ML092931583.

In any event, even if the values proposed by the Intervenors were used, they would not impact the results of the SAMDA analysis.[71] ER Section 7.5S.5 concludes that "[n]one of the severe accident mitigation design alternatives considered for the ABWR would be cost effective and mitigate the potential impacts (contamination and down time) from a large release severe accident at the existing units."[72] To reach this conclusion, STPNOC compared the monetized impacts in Table 7.5S-2 with the lowest cost SAMDA for the ABWR, which is $100,000.[73] If the values in Table 7.5S-2 were multiplied by a factor of four as suggested by the Intervenors, and if the replacement power costs for all of the co-located units were summed together, there still would be no SAMDA that would be cost-effective.[74] Furthermore, as discussed in ER Section 7.5S.5, there is no SAMDA for STP Units 3 and 4 that would prevent or mitigate the economic impacts of accidents in Units 1 and 2; therefore, multiplying the costs in Table 7.5S-1 by a factor of four also would not affect the results of the SAMDA analysis.

For these reasons, this contention does not raise a genuine dispute of material fact, contrary to 10 C.F.R. § 2.309(f)(1)(vi). This contention seeks to "flyspeck" the replacement power costs used in ER Section 7.5S, and use of the Intervenors' proposed costs would not affect the results of the SAMDA analysis. Accordingly, this contention should be dismissed.[75]

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[71] A SAMDA analysis only needs to be performed for Units 3 and 4, not for Units 1 and 2 (which are outside the scope of this proceeding).

[72] ER Letter, Attachment, at 7.

[73] *See* Technical Support Document for the ABWR, Table 4 (STP Attachment 6); *see also* NUREG-1503, at 20-87 ("The staff notes that the lowest cost modifications were estimated to cost about $100,000, and realistically would only partially reduce the residual risk for the ABWR.") (STP Attachment 4).

[74] Additionally, ER Table 7.3-1, which was unchanged during the addition of ER Section 7.5S, provides a highest replacement power cost for a severe accident at an ABWR unit of $7,400. ER at 7.3-5 (Rev. 3, 2009), *available at* ADAMS Accession No. ML092931583. Even if this value, which is for a unit that is never restarted, is used in place of the replacement power costs for a temporary shutdown of the STP units, there still would be no change in the outcome of the SAMDA evaluation.

[75] A contention that does not directly controvert a position taken by the applicant in the application is subject to dismissal. *See Tex. Utils. Elec. Co.* (Comanche Peak Steam Electric Station, Unit 2), LBP-92-37, 36 NRC 370, 384 (1992).

C. Contention CL-3

Contention CL-3 states:

> The Applicant's quantification of the replacement power costs in the event of a forced shutdown of nuclear units on the STP site is inadequate in that it does not take into account the increase of ERCOT market prices due to the market effects of a STP outage.[76]

The Intervenors rely upon the report from Mr. Johnson for this contention.[77] The Intervenors argue that the estimated replacement power costs in ER Section 7.5S are low because they do not account for the market effects in the ERCOT region due to the shutdown of the STP units in response to a severe accident scenario.[78] As discussed below, Contention CL-3 should be rejected because it is untimely, is immaterial, is not adequately supported, and does not demonstrate a genuine dispute of a material fact.

This contention suffers from the same defects as Contention CL-2. First, the replacement power cost estimates in ER Section 7.5S are based on NRC guidance set forth in NUREG/BR-0184. As discussed above with respect to Contention CL-2, this same approach for replacement power costs was used in ER Section 7.3, which the Intervenors did not contest as part of their petition to intervene. Therefore, the Intervenors' challenge to the use of the replacement power costs in NUREG/BR-0184 is untimely and without justification pursuant to 10 C.F.R. § 2.309(c) and (f)(2).

Additionally, ER Section 7.5S.5 shows a large margin between the estimated monetized impacts for replacement power costs and the lowest cost SAMDA. Even if the Intervenors' arguments regarding the effects of a shutdown of the STP units on the market price of power were accepted, the Intervenors have not demonstrated or even alleged that there would be any

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[76] Request at 8.

[77] *Id.*

[78] *Id.* at 8-9; Johnson Report at 5.

effect on the results of the SAMDA analysis given this large margin. Thus, the Intervenors have not shown or even alleged that any change in the estimation of replacement power costs would be material or demonstrate a genuine dispute of a material fact, contrary to 10 C.F.R. § 2.309(f)(1)(iv) and (vi).

Furthermore, contrary to 10 C.F.R. § 2.309(f)(1)(v), the Intervenors have provided no support to demonstrate that consideration of the market effects of shutting down the STP units would change the replacement power costs. They have not calculated any projected increases in replacement power costs. Instead, Mr. Johnson and the Intervenors make generalized statements that do not show a dispute with the ER. As the Commission has stated, "an expert opinion that merely states a conclusion (*e.g.*, the application is 'deficient,' 'inadequate,' or 'wrong') without providing *a reasoned basis or explanation* for that conclusion is inadequate because it deprives the Board of the ability to make the necessary, reflective assessment of the opinion."[79]

Additionally, this contention does not raise a genuine dispute of material fact. The Intervenors claim that "removing STP generation from the ERCOT market will allow less efficient units to set the market price."[80] However, the evaluation in ER Section 7.5S.5 is based upon the replacement power costs, not the costs of power from STP units. The replacement power costs account for the fact that replacement power is provided by less efficient units. In any event, even if the replacement power costs were to double or triple beyond those estimated by Mr. Johnson, the results of the SAMDA analysis for STP Units 3 and 4 would be unaffected.

Finally, the Intervenors are seeking a level of specificity that is simply not required by NEPA. The Intervenors would require that STPNOC speculate about possible changes in market

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[79] *USEC, Inc.* (American Centrifuge Plant), CLI-06-10, 63 NRC 451, 472 (2006) (emphasis added) (quoting *Private Fuel Storage*, *LLC* (Independent Spent Fuel Storage Installation), LBP-98-7, 47 NRC 142, 181 (1998)).

[80] Request at 9.

prices of electricity decades in the future.[81] Such speculation is not required by NEPA. As the Commission has explained, "NEPA also does not call for certainty or precision, but an *estimate* of anticipated (not unduly speculative) impacts."[82] STPNOC has provided this estimate of the replacement power costs, using a methodology identified by NRC guidance, and this is sufficient for NEPA. The Intervenors' attempt to "flyspeck" the ER by addressing "nuances," while not showing that their arguments are material.[83]

D. <u>Contention CL-4</u>

Contention CL-4 states:

> The Applicant's Environmental Report is inadequate in that it does not evaluate or take into account the impacts on ERCOT consumers and the disruptive impacts of potential price spikes and grid outages, which could be triggered by the simultaneous shutdown of all four units at STP.[84]

The Intervenors rely upon the report from Mr. Johnson for this contention.[85] The Intervenors argue that beyond replacement power costs, there would be impacts to the ERCOT consumers and the overall average prices of electricity in the ERCOT market due to factors such as price spikes and outages.[86] As discussed below, Contention CL-4 should be rejected because it is outside the scope of this proceeding, is not adequately supported, is immaterial, and does not demonstrate a genuine dispute of a material fact.

First, this contention raises an issue that is outside the scope of this proceeding. NEPA is an environmental statute, not an economic statute. Under NEPA, a NRC applicant is not

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81 *Id.* at 8-9; Johnson Report at 5.

82 *National Enrichment*, CLI-05-20, 62 NRC at 536.

83 *Grand Gulf*, CLI-05-4, 61 NRC at 13 (citations omitted).

84 Request at 9.

85 *Id.*

86 *Id.* at 9-10; Johnson Report at 5-7.

required to evaluate the economic impacts on consumers, such as the impacts of a proposed plant on ratepayers.[87] Therefore, Contention CL-4 should be rejected under 10 C.F.R. § 2.309(f)(1)(iii) because it does not raise a litigable issue under NEPA.

Additionally, contrary to 10 C.F.R. § 2.309(f)(1)(v), the Intervenors have not provided adequate support to demonstrate that a four unit shutdown at the STP site would trigger uncontrolled power outages. Mr. Johnson himself admits that the probability of a loss of the grid due to a shutdown of the STP units "may not be high."[88] When this low probability is multiplied times the low probability of a severe accident at the STP site, it is evident that the scenario in question is not within the rule of reason of NEPA. NEPA's rule of reason means that an "agency's environmental review, rather than addressing every impact that could possibly result, need only account for those that have some likelihood of occurring or are reasonably foreseeable."[89]

Furthermore, ER Section 7.5S shows a large margin between the monetized impacts and the lowest cost SAMDA. Mr. Johnson has not alleged let alone demonstrated that the factors that he raised would be sufficient to counteract the large margin in the SAMDA analysis. Accordingly, his allegations do not raise a genuine dispute of material fact and therefore are not sufficient for admission of this contention, contrary to 10 C.F.R. § 2.309(f)(1)(iv) and (vi).

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87 *See, e.g.*, *Portland Gen. Elec. Co.* (Pebble Springs Nuclear Plant, Units 1 & 2), CLI-76-27, 4 NRC 610, 614 (1976); *Detroit Edison Co.* (Enrico Fermi Atomic Power Plant, Unit 2), ALAB-470, 7 NRC 473, 474-75 (1978); *Puget Sound Power & Light Co.* (Skagit/Hanford Nuclear Power Project, Units 1 and 2), LBP-82-26, 15 NRC 742, 744 (1982).

88 Johnson Report at 7.

89 *See National Enrichment*, LBP-06-8, 63 NRC at 258-59 (citing *Shoreham*, ALAB-156, 6 AEC at 836). Additionally, the Intervenors appear to be requesting a worst case economic analysis. The Supreme Court has held that NEPA does not require a "worst case analysis," such as the one presented by the Intervenors here. *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 354 (1989).

E. Proposed Revisions to Contention 21

As noted above, the Intervenors requested that the Board revise Contention 21. The proposed revisions to Contention 21 state:

> A.) The Environmental Report is deficient because it fails to discuss how a large release of radiation from an affected unit(s) will impact safe shutdown at an unaffected unit(s).
>
> B.) The Environmental Report is deficient because it assumes there will be sufficient warning of an accident at an affected unit to allow an unaffected unit(s) to complete safe shutdown.
>
> C.) The Environmental Report is deficient because it assumes that a separation distance of 1500 feet is adequate to preclude impacts from fires and explosions originating from an affected unit on other co-located units.[90]

As discussed below, these arguments fail to satisfy the contention admissibility standards, and therefore the Board should reject the proposed revisions to Contention 21.

1. ER Section 7.5S Addresses Large Releases of Radiation

The Intervenors first argue that ER Section 7.5S is deficient because it does not discuss large releases of radiation.[91] The Intervenors infer from a statement in ER Section 7.5S.3 that "a large release would have an impact on safe shutdown of the unaffected units."[92] The Intervenors further state that STPNOC does not discuss large radiation releases based on the relatively low frequency of large releases and that STPNOC assumes a release large enough to frustrate safe shutdown will not occur.[93] These arguments by the Intervenors mischaracterize ER Section 7.5S and do not support revision of Contention 21.

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[90] Intervenors' Answer at 2.

[91] *Id.* at 2-3.

[92] *Id.* at 2.

[93] *Id.* at 3.

Contrary to the arguments of the Intervenors, ER Section 7.5S.3 evaluates large releases from severe accidents for the ABWR to determine whether the co-located units could be shut down safely. For example, ER Section 7.5S.3 evaluates whether operators would have sufficient warning of an accident to safely shutdown co-located units and concludes that "[t]he time increment from general emergency warning time until the first release of radioactivity to the environment for all ten accident sequences is greater than the time required to put an unaffected unit into a stable long-term decay heat removal condition."[94] Similarly, ER Section 7.5S.4 evaluates the impact of large releases on co-located units and concludes that all equipment necessary to complete safe shutdown would operate as designed.[95]

Furthermore, as discussed in Section IV.C above, ER Section 7.5S.6 includes an evaluation that arbitrarily postulates that a severe accident at one unit could adversely impact safe shutdown of the other three units. Therefore, ER Section 7.5S.6 includes the very type of evaluation requested by this proposed revision to Contention 21.

In summary, ER Section 7.5S addresses the topics that the Intervenors claimed were not addressed. As has been ruled by other licensing boards, if a petitioner submits a contention of omission, but the allegedly missing information is indeed in the license application, then the contention does not raise a genuine issue and should be rejected.[96]

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[94] ER Letter, Attachment, at 4. A similar conclusion is made for severe accidents originating at STP Units 1 or 2. *Id.*, Attachment, at 5.

[95] *Id.*, Attachment, at 5-6.

[96] *See Dominion Nuclear Conn., Inc.* (Millstone Nuclear Power Station, Units 2 & 3), LBP-04-15, 60 NRC 81, 95-96 (2004).

2. ER Section 7.5S Justifies Sufficient Warning of an Accident

The Intervenors next argue that ER Section 7.5S does not "justify the assumption that any particular duration of time will be available to complete safe shutdown."[97] This argument mischaracterizes ER Section 7.5S and does not support revision of Contention 21.

Contrary to the Intervenors' assertion, the ER revision does not make an assumption that there will be sufficient time to shutdown. Instead, ER Section 7.5S.1 identifies the time (3 hours) needed for safe shutdown, and ER Section 7.5S.3 shows that the accident scenarios progress over a longer period of time.[98] Based on this timing and the ability of the equipment to support safe shutdown, ER Section 7.5S concludes that the co-located units could be safely shutdown. Therefore, STPNOC did not simply assume that there would be sufficient time to shutdown the co-located units, as argued by the Intervenors; STPNOC performed an evaluation to demonstrate this. Proposed revision B to Contention 21 provides no basis for disputing these statements, contrary to 10 C.F.R. § 2.309(f)(1)(v).

Additionally, the Intervenors' argue that ER Section 7.5S fails to consider the environmental impacts of accidents on co-located units. This argument mischaracterizes the information provided in this ER section. ER Section 7.5S.6 postulates that a severe accident at one unit could cause a simultaneous severe accident at each of the co-located units and evaluates the corresponding environmental impacts.[99] Because ER Section 7.5S.6 provides the information claimed to be missing by the revised contention, the Intervenors have not demonstrated a genuine dispute of material fact, contrary to 10 C.F.R. § 2.309(f)(1)(vi).[100]

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[97] Intervenors' Answer at 4.

[98] ER Letter, Attachment, at 2, 4-5.

[99] *Id.*, Attachment, at 8.

[100] If a petitioner submits a contention of omission, but the allegedly missing information is indeed in the license application, then the contention does not raise a genuine issue. *See Millstone*, LBP-04-15, 60 NRC at 95-96.

3. ER Section 7.5S Adequately Evaluates Safe Shutdown

The Intervenors argue that the submittal "does not consider the impacts on safe shutdown under the full spectrum of damage states."[101] This argument mischaracterizes ER Section 7.5S and does not support revision of Contention 21.

Contention 21 was limited to design basis accidents and severe accidents.[102] Attempts by the Intervenors to broaden this contention "to include a full spectrum of damage states" are untimely under 10 C.F.R. § 2.309(c) and (f)(2). Furthermore, the Intervenors do not identify any accidents that STPNOC has not considered, and therefore do not provide an adequate basis for this contention or demonstrate a genuine dispute of a material fact, contrary to 10 C.F.R. § 2.309(f)(1)(v) and (vi).

The Intervenors also argue that "the assertion by the Applicant that a separation distance of 1500 feet obviates the need for consideration of fire and explosion impacts is arbitrary and unsupported in the record."[103] The Intervenors have mischaracterized ER Section 7.5S. Contrary to their assertion, this section does not state that the distance between the units obviates the need for consideration of fires and explosions. Instead, this section states that FSAR Section 2.2S.3 has already evaluated potential accidents that could impact STP Units 3 and 4, including those resulting in fires or explosions, and demonstrates that the units are located at a safe distance and are not at risk to impacts from explosions, fires, or release of toxic chemicals from other units.[104] Therefore, the remainder of Section 7.5S focuses on radiological releases from design basis accidents and severe accidents, rather than on fires or explosions from, for example,

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[101] Intervenors' Answer at 4.

[102] *See South Texas Project*, LBP-09-21, slip op. at 36-39.

[103] Intervenors' Answer at 4.

[104] ER Letter, Attachment, at 1.

a chemical storage facility located at one of the units.[105] Contrary to 10 C.F.R. § 2.309(f)(1)(v), the Intervenors have provided no basis for contesting the analyses of fires and explosions in the FSAR or ER Section 7.5S.

The Intervenors also reference a statement made by the Board that 1500 feet between units does not preclude a severe accident from affecting other units.[106] The statement by the Board was not a finding of fact, but instead was simply a statement that the Board could not assume that there would be no impact absent information in the ER to the contrary. As discussed above, STPNOC has now provided such an evaluation, and the Intervenors have not provided any basis for contesting that analysis.

In summary, the Intervenors' proposed revisions to Contention 21 are unsupported and mischaracterize the evaluations in ER Section 7.5S. Accordingly, the proposed revisions should be rejected.

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[105] *Id.*, Attachment, at 1-9.

[106] Intervenors' Answer at 4.

VI. CONCLUSION

For the foregoing reasons, the new and revised contentions submitted by the Intervenors related to ER Section 7.5S should be rejected.

Respectfully submitted,

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Dated in Washington, D.C.
this 22nd day of January 2010

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	Docket Nos. 52-012-COL
	)	52-013-COL
STP NUCLEAR OPERATING COMPANY	)	
	)	
(South Texas Project Units 3 and 4)	)	January 22, 2010

CERTIFICATE OF SERVICE

I hereby certify that on January 22, 2010 a copy of "Applicant's Answer Opposing New and Revised Contentions Regarding Environmental Report Section 7.5S" was served by the Electronic Information Exchange on the following recipients:

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STP Attachment 1

Table 19E.2-16 Summary of Critical Parameters for Severe Accident Sequences

Accident	Time of Vessel Failure	Fission Product Release Time	Time of Rupture Disk Failure	End of CsI Release	Release Fraction of CsI @ 72 hours
LCLP-PF-R-N	1.8 h	20.2 h	20.2 h	100 h	<1E–7
LCLP-FS-R-N	1.8 h	31.1 h	31.1 h	76 h	1E–7
LCHP-PS-R-N	2.0 h	25.0 h	25.0 h	50 h	<1E–7
LCHP-FS-R-N	2.0 h	50 h*	50 h*	125 h*	<1E–7*
LCHP-PF-P-M	2.0 h	18.1 h	N/A	70 h	8.8E–2
SBRC-PF-R-N	12.3 h	23.5 h	23.5 h	100 h	<1E–7
LBLC-PF-R-N	1.4 h	19.1 h	19.1 h	125 h	<1E–7
LBLC-FS-R-N	1.4 h	29.5 h	29.5 h	67 h	<1E–7
NSCL-PF-R-N	1.3 h	18.7 h	18.7 h	105 h	<1E–7
NSCL-FS-R-N	1.3 h	30.7 h	30.7 h	69 h	<1E–7
NSCH-PF-P-M	1.3 h	17.8 h	N/A	65 h	7E–2
NSCH-FS-R-N	1.3 h	50 h*	50 h*	125 h*	<1E–7*
NSRC-PF-R-N	5.6 h	8.6 h	8.6 h	110 h	<1E–7
NSRC-FS-R-N	5.6 h	26.4 h	26.4 h	120 h	<1E–7

* Release parameters are approximate. See sequence discussion for more detail.

STP Attachment 2

Table 19E.3-6 Event Release Parameters

Accident	P(i)*	TL	DR	TLL	FPR	RH	Release Fractions† NG	Iodine	Cesium
NCL		2.7	10	1.7	3.3E+5	37	0.044	2.3E-05	2.3E-05
CASE 1		20	1	19.2	3.3E+5	37	1	1.5E-07	1.3E-05
LCHPFSRN									
LCHPPSRN									
LBLCFSRN									
SBRCPFRN									
LCLPPFRN									
LCPFSRN									
CASE 2		19	1	18.2	3.3E+5	37	1	5.0E-06	5.0E-06
LCLPPFCR									
LCLPFSCR									
CASE 3		50	10	49.2	3.3E+5	37	1	2.8E-04	2.2E-03
LCHPFSD90									
CASE 4		20	1	19.2	3.3E+5	37	1	1.6E-03	1.6E-03
DF100FSR									
DF100PFR									
CASE 5		19	1	19.2	3.3E+5	37	1	6.0E-03	5.3E-04
LBLCPFRN									
CASE 6		19	10	18.2	3.3E+5	37	1	3.1E-02	7.7E-02
LCHPPSD90									
LBLCPFD90									
LBLCFSD90									
CASE 7		20	10	19.2	3.3E+5	37	1	8.9E-02	9.9E-02
LCLPFSD90									
LCHPPFPM									
LCLPPFD90									
CASE 8		2	10	1.2	1.0E+6	37	1	1.9E-01	2.5E-01
LCHPPFEH									
LCHPPFBR									
LCHPPFBD									
CASE 9		23.6	10	12.2	3.3E+5	37	1	3.7E-01	3.6E-01
SBRCPFD90									

* Probabilites not part of DCD (Refer to SSAR).
† Group 5-8 negligible release

Note:

See Subsection 19E.3.2.2 for definition of parameters in this table.

STP Attachment 3

19Q.12.4 Reliability Goals (Input to RAP)

The following assumed system unavailabilities were determined to be important in minimizing shutdown risk and are included in the ABWR Reliability Assurance Program:

System	Unavailability (Per Demand)
RHR (SDC)	†
RHR (LPFL)	†
HPCF	†
CRD	†
CTG	†
EDG	†
Offsite Power	†
ADS	†
DC Power	†

† Not a part of DCD (refer to SSAR)

19Q.12.5 Conclusions

The ABWR has been evaluated for risks associated with shutdown conditions and for all postulated events, the risk has been determined to be low. Multiple means of removing decay heat and supplying inventory makeup have been identified that along with appropriate Technical Specifications and outage procedures result in acceptably low shutdown risk levels for the ABWR.

STP Attachment 4

19 SEVERE ACCIDENTS

19.1 Probabilistic Safety Assessment

19.1.1 Executive Summary

As part of its advanced boiling water reactor (ABWR) design certification application, GE Nuclear Energy (GE) has performed a design-specific probabilistic risk assessment (PRA) as required by 10 CFR 52.47(a)(1)(v). GE submitted a Level 3 PRA (i.e., the PRA calculated core damage frequencies, conditional containment failure probabilities, and conditional offsite consequences) that addresses internal initiating events. The PRA also evaluates seismic, internal flood, and fire-initiating events.

The staff reviewed the ABWR PRA to investigate design insights and to determine its quality. The staff concluded that the quality of the ABWR PRA is adequate for supporting and improving the ABWR design process; providing relative importance of sequences (as well as identifying important structures, systems, and components (SSCs)) leading to core damage or containment failure; and searching for design and procedure vulnerabilities that could be eliminated on a cost-benefit basis.

The draft safety evaluation report (DSER) (SECY-91-309) and the draft final safety evaluation report (DFSER) included a number of unresolved issues. Since both evaluations were too detailed and extensive to be repeated in this safety evaluation, the staff totally revised its evaluation as reflected in this report. As stated herein, those issues that were individually listed in the previous two evaluations have been adequately addressed by GE in its application.

The staff concludes, based on its review of the ABWR PRA, that the ABWR is of a robust design, that the design is an improvement over existing designs, and that the design meets the Commission's safety goals described in 51 FR 28044 and 51 FR 30028 published August 21, 1986, for internal events (see FSER Section 19.1.3.8.3). The Commission has determined that it is acceptable for GE to submit external event analyses that provide insights needed to identify design and procedure vulnerabilities; provide insights needed for inclusion in areas such as the reliability assurance program (RAP); and inspections, tests, analyses, and acceptance criteria (ITAAC); but do not provide core damage frequency estimates suitable for use in comparison to the Commission's safety goals or in comparison to the Electric Power Research Institute's (EPRI's) Public Safety Requirement, which states

> "The design is considered to have met the EPRI risk requirement if the mean complementary cumulative distribution function (CCDF) for whole-body dose developed for a 0.8 km (one-half mile) radius falls outside the region bounded by a lower limit for frequency at 1E-6 per year and has a lower limit for consequences of 25 rem whole-body dose at 0.8 km (one-half mile). The EPRI goal is based on consideration of both internal and external initiators"

Although direct comparison of external-event results to these goals is not possible, the ABWR design has significant margins above the design bases for seismic, fire, and internal flood-initiating events and, where computed, has low estimated core damage frequencies from these bounding analyses. The staff believes that the ABWR design meets the Commission's safety goals.

The staff finds that there is an acceptable balance of preventative and mitigative features in the ABWR design. The core damage frequency estimates for internal events reported in the ABWR PRA are on the order of 1E-7 per year. Table 19.1-1 lists the most important internal initiating events and Table 19.1-2 lists the top 20 internal event sequences leading to core damage. Station blackout (SBO) contributes about 70 percent of the internal events core damage frequency (i.e., its absolute value is about 1E-7 per year, which is low when compared to the figures in most recent boiling water reactor (BWR) PRA studies). Table 19.1-3 lists the most important sequences leading to core damage from seismic, internal flood, and fire event initiators.

Table 19.1-1 ABWR PRA initiating event contributors to CDF (Level 1, internal events)

Initiating Event	Events Per Yr.	CDF x 1E-8	Percent CDF
Station blackout < 2 hrs	1.2E-6	6.7	43%
Station blackout 2 < X < 8 hrs	4.5E-7	2.6	16%
Station blackout > 8 hrs	1.6E-8	1.7	11%
Isolation/loss of feedwater	0.18	1.7	11%
Unplanned manual reactor shutdown	1.0	1.2	7%

Table 19.1-2 Important sequences leading to core damage (internal events)

Sequence Description (Top 20 sequences)	CDF (Per Year)	Percent CDF	Plant Damage Class
SBO from 0.5 to 2 hrs, RCIC unavail. because of test or maintenance (T/M)	2.4E-8	15.6	ID
SBO more than 8 hrs	1.6E-8	10.4	IB-2
SBO from 0.5 to 2 hrs, RCIC turbine mech. failure	1.3E-8	8.6	ID
SBO from 2 to 8 hrs, RCIC unavail. because of T/M	8.9E-9	5.7	IB-1
SBO from 0.5 to 2 hrs, RCIC pump fails	8.3E-9	5.3	ID
SBO from 0.5 to 2 hrs, RCIC lubrication system fails	5.1E-9	3.3	ID
SBO from 2 to 8 hrs, RCIC turbine mech. fails	4.9E-9	3.1	IB-1
Loss of feedwater/isolation, failure to inject with feedwater, conditional containment failure (CCF) of MUX, operator fails to manually initiate feedwater after 30 min.	4.6E-9	2.9	IA
Reactor trip, failure to inject feedwater, CCF of MUX, operator fails to manually initiate feedwater after 30 min.	3.1E-9	2.0	IA
SBO from 2 to 8 hrs, RCIC pump fails	3.0E-9	1.9	IB-1
Loss of feedwater/isolation, failure to inject feedwater, CCF of system logic unit, operator fails to manually initiate feedwater after 30 min.	2.3E-9	1.5	IA
Loss of feedwater/isolation, failure to inject feedwater, operator fails to manually initiate feedwater after 30 min., CCF of remote MUX	2.3E-9	1.5	IA
SBO from 0.5 to 2 hrs, valve E51-F011 fails to close after RCIC pump has started	2.2E-9	1.4	ID
SBO from 0.5 to 2 hrs, valve F037 fails closed (NCFC)	2.1E-9	1.3	ID
SBO from 0.5 to 2 hrs, valve F004 fails closed (NCFC)	2.1E-9	1.3	ID
SBO from 0.5 to 2 hrs, valve E51-F011 fails to open when RCIC pump starts	2.1E-9	1.3	ID
Loss of feedwater/isolation, failure to inject feedwater, battery CCF, loss-of-offsite line 1 power	2.0E-9	1.3	IA
SBO from 2 to 8 hrs, RCIC lubrication fails	1.9E-9	1.2	IB-1
Turbine trip, failure to inject feedwater, CCF of MUX, operator fails to manually initiate feedwater after 30 min.	1.8E-9	1.2	IA
SBO from 0.5 to 2 hrs, isolation signal logic fails	1.7E-9	1.1	ID
Totals	1.1E-7	71.9	

Table 19.1-3 Important sequences for external events (seismic, fire, and internal floods)

Seismic Events Sequences chosen for having low HCLPF[1] values or needing few SSC failures	Sequence HCLPF
Failure of emergency dc power	0.74 g
Emergency ac/emergency SW and fire water	0.62 g
Emergency ac/emergency SW and scram	0.62 g
Reactor or control building, containment, RPV pedestal, or RPV supports	1.11 g
ATWS and SLCs failure	0.62 g
ATWS and SLCs and high-pressure core flood	0.62 g

Internal Flood Events Sequences chosen as being most challenging and having worst consequences	Estimated CDF
Control building: large pipe break in RSW, operator fails to isolate flooding, auto RSW pump trip fails, water flows to remaining RSW pump rooms, operator fails to respond to flooding alarm, RSW fails.	2E-9 per year
Reactor building: break in fire water standpipe or line from CST, operator does not respond to alarm to isolate flood, overfill lines to corridor are clogged, all three electrical rooms on floor B1F flood, ac power is lost to all make-up systems.	2E-10 per year
Turbine building: break in CWS system, isolation valves in CWS lines fail to close, water fills up and runs out of the condenser pit, fire door between the turbine building and the service building is either open or fails open allowing water into service building, service building floods and a door between the service building and the control building fails open or is open, water entering the control building causes electrical power supplies and all three divisions of RCW to fail.	3E-9 per year

Fire Sequences chosen that had a core damage frequency of 1E-6 or higher before the plant design was improved	Estimated CDF (considered conservative)
Fire in the control room causes its evacuation, feedwater fails, RCIC or one high-pressure core flood train fails, either one train of low-pressure core flood train or manual depressurization fails.	less than 1E-6 per year

1 - High confidence with low probability of failure that the structure, system, or component will fail at the given peak ground acceleration.

Note: Because of the assumptions and methods used in the ABWR shutdown risk evaluation, no dominant sequences leading to core damage could be determined. NUREG-1449 did identify various important scenarios that were potential contributors to core damage in BWRs during shutdown. Conclusions from NUREG-1449 are based on actual nuclear power plant operating experience.

The internal events core damage frequency estimate is very low and is a reflection of GE's efforts to systematically minimize the effect of sequences or initiators that have been important contributors to core damage frequency in previous BWR PRAs. A brief discussion is necessary on the implications of the low estimated core damage frequency for internal events for the ABWR. Estimated core damage frequency values with absolute values less than 1 in a million years should not be taken literally as the expectation of the "true" core damage frequency of the design. Rather, this value should be taken as a reflection of the conscientious engineering and design effort to reduce or eliminate the contributors to core damage frequency found in previous PRAs. When core damage frequencies of one in a hundred thousand or a million years are estimated in a PRA, it is the areas of the PRA where modeling is least complete, supporting data are sparse, or even nonexistent that actually could be the more important contributors to risk. Areas not modeled or incompletely modeled include errors of commission, sabotage, rare initiating events, construction errors, design errors, control systems, ageing, systems interactions, human interaction with smart control rooms, and human errors.

For seismic initiating events, GE submitted a PRA-based seismic margins analysis. This method eliminates the uncertainties associated with picking an appropriate seismic hazard curve, while still providing the insights needed to judge the ability of the design to withstand beyond-design-basis earthquakes. With a PRA-based seismic margins analysis, rather than developing an estimated core damage frequency, the method estimates the margin the design has beyond the design basis safe shutdown earthquake (SSE) (which is 0.3g for the ABWR) and identifies any weak links in the design. GE reported that all sequences leading to core damage from a purely seismic event were found to have a high confidence with low probability of failure (HCLPF) value of 0.6g or higher. An HCLPF roughly represents the g-level acceleration at which a SSC is believed to fail 5 percent or less of the time with a 95 percent confidence level. The staff finds that the ABWR's HCLPF ($\geq$ 0.5g) demonstrates that a significant margin exists beyond the design basis earthquake level.

For internal floods that occur at power, GE performed a PRA internal flood analysis that assumed that once flood water reaches a level high enough to cause the failure of any piece of equipment in an area, then all the equipment in that area instantly fails and is unrecoverable. This analysis estimated that the core damage frequency from internal floods was on the order of 1E-8 per year. This number was particularly low because the ABWR design has three safety divisions that are physically separated. For internal floods during shutdown, GE developed guidelines for the COL applicant for configuring shutdown cooling divisions such that one division would be in operation, one isolated and in standby, and one in maintenance. It is believed that the core damage frequency from this configuration should not exceed 1E-6 per year and probably can be at least an order of magnitude lower, given the conservatism of the assumptions in the analysis.

For fires, GE submitted a fire analysis that was a combination of the Fire Induced Vulnerability Evaluation (FIVE) methodology developed by EPRI and the internal events PRA. This analysis assumed that, if a fire occurred in any portion of a fire area, all equipment in the area failed instantly. The GE fire analysis estimated the core damage frequency from fires to be on order of 1E-6 per year.

The design basis analysis for tornados in the ABWR is such that the ABWR is designed to be able to withstand tornados that occur with a frequency in the range of 1E-7 per year. Since the plant is designed to handle these low frequency tornados and is already analyzed for loss-of-offsite power events, the staff does not consider it necessary to analyze design basis tornados probabilistically.

The staff finds that the ABWR design is adequate to limit exposure to risk when the plant is operated in Modes 3, 4, and 5 (hot shutdown, cold shutdown, and refueling, respectively). The staff finds that the ABWR design includes enhanced features that reduce risk during shutdown operations when compared to operating BWRs. These features specifically address the more risk-significant operations during shutdown identified in NUREG-1449 including three independent residual heat removal (RHR) divisions, three emergency diesel generators (EDGs), an ac-independent water addition (ACIWA) system, an alternate onsite combustion turbine generator (CTG), and proper plant electrical and physical separation and layout.

The results of the Levels 2 and 3 portion of the ABWR PRA indicate that the ABWR containment is quite robust and able to accommodate severe accidents with a low attendant probability of containment failure. Both GE and staff estimates of the ABWR conditional containment failure probability (CCFP) are within the Commission's containment performance goal (0.10). Using the structural integrity definition, GE's estimate of CCFP is 0.005, whereas the staff's estimate is 0.026.

Based on the Level 3 PRA, the estimated total risk to the public for the ABWR is extremely small. GE's analysis indicates a total dose of about 0.3 person-rem over the

60-year plant life. The staff's estimate is about 1 person-rem. The staff estimated that total risk is dominated by events that lead to early containment failure and containment bypass. This is consistent with results from PRAs for operating plants.

GE made a number of design modifications to the ABWR both early in the design and later during the staff's review of the ABWR PRA that were motivated by the results of the PRA. Table 19.1-4 describes some of the modifications made to the design by GE.

Table 19.1-4 Examples of cost-effective PSA-inspired design/procedure modifications to the ABWR design

Area Modified	Modification
Core cooling systems	GE found it only needed three, not four, ECCS divisions.
Reactivity control	GE found alternate rod insertion reliability was such that less expensive ATWS mitigation system was acceptable.
Instrumentation	GE found that it could eliminate 60 percent of sensor instrumentation in the reactor safety systems without affecting plant safety.
AC-independent water addition (ACIWA) system	System added to ABWR design. Staff believes that it is the most important system for helping to prevent severe accidents.
Combustion turbine	System added to ABWR design. In combination with ACIWA, it virtually eliminates SBO as a consideration.
Lower drywell flooder (LDF)	System added to ABWR design. Floods lower drywell in event that vessel fails and corium enters lower drywell.
Containment Overpressure Protection System (COPS)	System added to ABWR design. If an accident occurs that pressurizes containment, the COPS allows for release of the pressure (90 psig set point) with the capability to reclose vent path.
Control for fourth SRV on remote shutdown panel	Extra SRV control added based on ABWR fire analysis. Mitigates control room fire.
Water-level sensors, pump trip and valve isolation circuits	Pump trips added for floods in turbine and control building as well as valve isolation signals on high water level. Pipe length between first RSW isolation valve and control building limited to help assure pipe break will not cause unacceptable results.
Containment concrete	Basaltic concrete used rather than limestone concrete to limit production of noncondensible gases from a core on floor event.

GE and the staff have drawn a substantial number of significant safety insights from the ABWR PRA that have or will affect the design, construction, operation, maintenance, and regulation of the ABWR. These insights are discussed in more detail in Section 19.1.3 in the final safety evaluation report (FSER) and in Section 19.8 in the SSAR. Appendix 19K in the SSAR lists those SSCs that are to be included in a COL action item that lists proposed inputs for the COL applicant's operational reliability assurance process (O-RAP) and design reliability assurance program (DRAP) based on the ABWR PRA. Appendix K in the FSER lists those safety insights that were motivated by the PRA. The disposition of these insights is documented in the appendix and indicates if the insights are in ITAAC, Tier 2 information, technical specifications (TS), COL action items, Interface Items, or RAP.

It is the staff's view that the mean core damage frequency for the ABWR from internal, external, and shutdown events is probably on the order of 1E-6 or less assuming the plant is constructed, maintained, and operated in accordance with the SSAR. This judgment is based on the staff's understanding of operating plant experience and PRA results, design improvements in the ABWR relative to operating reactors, and insights from the staff's review of the ABWR PRA. Furthermore, it should be emphasized that there are large uncertainties in internal event core damage frequency estimates. The external event analyses for the ABWR were quasi-probabilistic and were designed to uncover vulnerabilities in the design rather than generate specific core damage frequency estimates. Also, the shutdown risk evaluation was quasi-probabilistic, using PRA-based techniques to determine the reliability of shutdown cooling and to examine the possibility of determining plant configurations that would limit exposure to risk. The staff's review of the shutdown risk evaluation reflected the insight from previous PRAs that human error was the greatest contributor to shutdown risk. However, human error analysis methods still cannot accurately predict human response to various circumstances. This fact increases the uncertainty of the estimated bottom-line core damage frequency numbers for shutdown events.

GE conducted uncertainty analyses for the Level 1 portion of the ABWR PRA. GE reported that the internal event core damage frequency distribution had a mean value of 1.6E-7 per year and an error factor (EF) of about 4.2 (where the EF is the ratio of the 95th percentile to the median of the lognormal distribution). The 95th and 5th percentiles reported by GE were 4.5E-7 per year and 3.8E-8 per year, respectively. GE used a lognormal distribution for most random variables in the ABWR PRA, which is a mathematical simplification and assumption that is commonly used in PRA evaluations. The actual distribution for most variables is not known. Use of the lognormal distribution in lieu of the "actual" distribution adds an unquantifiable uncertainty to the evaluation, particularly in the bottom-line numbers.

GE performed importance analyses in order to determine the most important structures, systems, and components (SSCs) to be added to the RAP. GE used two importance measures: risk achievement worth ratio and fussell-vesely importance. The analysis identified scram function and its attendant equipment as very important. Station batteries are similarly important, since dc power controls the automatic depressurization system (ADS) as well as many pumps and valves. Another insight is the importance of reactor core isolation cooling (RCIC). This is because it is ac-independent, reliable, and provides high-pressure injection. These attributes are important for mitigating SBOs.

The probabilistic shutdown risk evaluation performed by GE concluded that the ABWR design could be maintained in configurations during Modes 3, 4, and 5 so that the estimated conditional core damage frequency was very low. The staff noted that estimates of core damage frequency and risk at shutdown for the ABWR design have much larger uncertainties than do such estimates for internal events in Modes 1 and 2. In the SSAR, GE presented sample plant configurations that help limit risk when shutdown occurs. The staff finds that the ABWR design, through appropriate shutdown planning, contingency planning, and operator instrumentation, can be configured and maintained in Modes 3, 4, and 5 in a manner that helps to reduce the chances of core damage or releases to the environment to a point where shutdown risk does not represent a disproportionate risk to the public.

19.1.2 Introduction

As part of the ABWR design certification application, GE submitted the ABWR PRA in response to 10 CFR 52.47, the Commission's Policy Statement on Severe Reactor Accidents Regarding Future Designs and Existing Plants, described in FR Vol. 50, No. 153, dated August 8, 1988, p. 32138 dated August 8, 1991, and the ABWR Licensing Review Bases. The staff's assessment included the traditional evaluation of events that could lead to core damage and offsite consequences as well as an evaluation of what the ABWR PRA revealed about the ABWR design.

The general objectives of the staff's review of the ABWR PRA were (a) to identify safety insights based on the performance of systematic risk-based evaluations of the ABWR design; (b) to determine in a quantitative manner whether the ABWR design represents a reduction in risk over existing plants; (c) to examine the balance of preventive and mitigative features of the design; (d) to

assess the reasonableness of the risk estimates documented in the PRA and other risk-related documents submitted as part of the FDA application package, and (e) to support pre- and postcertification activities such as ITAAC, RAP, TS, and completion of site-specific design details (e.g., ultimate heat sink). In addition, the ABWR PRA was used to both determine how the ABWR design related to various safety goals and discover design and procedural vulnerabilities.

The objectives are drawn from 10 CFR 52.47, the Commission's Policy Statement on Severe Reactor Accidents Regarding Future Designs and Existing Plants, the Commission's Safety Goal Policy Statement, the Commission approved positions concerning the analyses of external events contained in SECY-93-087, and the Commission's interest in the use of PRA to help improve future reactor designs. In general, these objectives have been achieved by the ABWR PRA and the staff's review. The staff's proposed applicable regulation for the analysis of external events for the ABWR PRA is as follows:

> The application for design certification must contain a probabilistic risk assessment that includes an assessment of internal and external events. Simplified probabilistic methods and margins methods may be used to assess the capacity of the standard design to withstand the effects of external events such as fires and earthquakes. Seismic margin analysis must consider the effects of earthquakes with accelerations approximately one and two-thirds the acceleration of the safe-shutdown earthquake.

The staff believes that if its review were to concentrate on bottom-line numbers or merely on the quality of a PRA, the most important insights from a PRA could receive inadequate attention. In Section 19.1.3, the staff reported on its investigation of those safety insights that are revealed by the ABWR PRA about the ABWR design. These insights include those that are to be passed on to the COL applicant, insights into the balance of prevention and mitigation, design vulnerabilities, and aspects of the design that tend to reduce or exacerbate risk estimates. The results of this broadened perspective are multifold. GE's systematic evaluation of the ABWR design has accomplished the following:

- Identified important areas where minor design modifications will help confirm that the potential for severe accidents is maintained at a low level
- Helped GE to identify the most safety-important equipment to be included in the RAP
- Provided the COL applicant with information about what is most important about the ABWR design and operation from a safety standpoint
- Helped confirm for the staff that the ABWR design is robust against internal and external events.

GE provided a list of important safety insights from the ABWR PRA including internal and external events and events during all modes of operation. This list, which was developed from a systematic process, is described in detail in SSAR Section 19.9 and is detailed in Appendix K in the FSER. As indicated in this table, GE recommended and staff agreed that a subset of these insights be included in the design control document (DCD) as ITAAC, Interface Items, or Tier 1 or Tier 2 material.

During the construction stage, the COL applicant will be able to consider as-built information. The staff concludes that updated PRA insights, if properly evaluated and utilized, could strengthen programs and activities in areas such as training, development of emergency operating procedures, reliability assurance, maintenance, and 10 CFR 50.59 evaluations. The staff recommends that the design-specific PRA developed to meet 10 CFR 52.47 be revised to account for site-specific information, as-built (plant-specific) information refinements in the level of design detail, and design changes. These updates are the responsibility of the COL applicant. As plant experience data accumulate, failure rates (taken from generic data bases) and human errors assumed in the design PRA are to be updated and incorporated, as appropriate, into ORAPs.

19.1.3 Advanced Boiling Water Reactor Probabilistic Risk Assessment-Based Safety Insights

Insights gleaned from a PRA can provide significant perception into the design and operation of a nuclear power plant. This section documents the insights derived by GE and the staff about the ABWR design based on the ABWR PRA.

19.1.3.1 Technical Insights Summary

In developing the ABWR design, GE significantly reduced the dominant contributors to core damage frequency found in most current BWR plant-specific design PRAs. The success of this attempt is substantiated by the low estimated core damage frequency for internal events recorded in the ABWR PRA (1.6E-7 per year) and the staff's conclusion documented in Section 19.1.4 that, on balance, the ABWR PRA was performed in an acceptable manner. The estimated core damage frequency from internal floods is about 7E-9 per year. The fire analysis performed by GE for the ABWR produced a core damage

frequency estimate of about 1E-6 per year. Because of conservatism in the analyses, the staff does not believe that the fire and internal flood core damage frequency estimates should be compared to those of internal events. The seismic analysis performed by GE was a PRA-based margins analysis that does not provide core damage frequency estimates. The margins analysis demonstrated that the ABWR design is robust for seismic events well beyond the design basis. The staff finds that the ABWR design, if built, maintained, and operated as assumed in the ABWR PRA, represents a reduction in risk when compared to the current design of BWRs.

It is important to understand what contributes to core damage frequency and risk in the ABWR design. Internal initiating events that are dominant contributors to core damage frequency include SBO, loss of offsite power, and vessel isolation or loss of feedwater. Failure of RCIC, the multiplexing transmission network, the station batteries, and the trip logic units are the most important contributing failures. SSAR Section 19K discusses the SSCs found to be most important in the PRA for internal and external events and when the plant is in modes other than full power. Table 19.1-2 provides a list of important sequences leading to core damage or risk for internal events. Table 19.1-3 provides a list for external events sequences.

For events occurring during modes other than full power, the ABWR design provides enhanced protection over the designs of many operating plants in that it has three fully separated safety divisions. To make use of this redundancy for maintenance purposes and still maintain an appropriate level of protection when in modes other than full power, GE has developed tables (See SSAR Tables 19Q.7-2 to 19Q.7-4) that list combinations of equipment that, if kept operable while in Modes 3, 4, and 5, will help ensure that a severe accident does not occur. These tables have the goal of maintaining a conditional core damage frequency of less than 1E-5 per year should the operating train of RHR cooling become unavailable. Since GE assumed that a loss of RHR cooling (i.e., of the operating train) has an occurrence rate of once per 10 years (GE's assumption is that during a 10-year period with all its included shutdowns there will be one loss of shutdown cooling event — 0.1 per year), this gives a frequency of core damage of less than 1E-6 per year when operating in Modes 3, 4, and 5. In the shutdown analysis, it is conservatively assumed that all equipment not specifically referred to in the tables as "operable" is "inoperable." During shutdown, it is conservatively assumed that any core damage would result in a large release, since the containment would be open much of the time. The staff and GE noted that separation of safety divisions is not always maintained during maintenance outages. To help assure that fires and floods cannot become common cause failures of all three divisions when in modes other than full power, GE has developed guidelines for plant operation. These guidelines would have one division isolated and in standby, another division operating in the shutdown cooling mode but not necessarily isolated, and another in maintenance. The staff believes that a safety-oriented approach to planning and controlling an outage is needed and that such an approach will reduce risk during Modes 3, 4, and 5. It recommends that COL applicants make use of the guidance provided by GE in Section 19Q of the SSAR regarding outage planning and control.

For seismic events, fires, and internal floods, the ABWR design has specific advantages over many current designs. The seismic design bases for the ABWR is a 0.3*g* SSE. In simple terms, the ABWR design can be built at any site that has its site-specific spectrum bounded by the design bases spectrum. Such a site might normally have an SSE of 0.2*g* assigned to it. However, the ABWR will be built to the 0.3*g* SSE standard, regardless. This creates an additional explicit seismic robustness at most potential sites east of the Rocky Mountains. For fires and internal floods, the existence of three separated safety divisions along with a diesel-driven fire water pump and an alternative water supply (that will remain functional following a design bases earthquake) external to the reactor building provide design improvements that significantly reduce potential core damage.

External events such as external flooding and hurricanes may be analyzed by a designer in a bounding manner in order to minimize the chances that the design has vulnerabilities to site-specific external events. GE did not chose to evaluate such external events at the Design Certification stage. The staff worked with GE to assure that GE was aware of the potential for vulnerabilities to such external events. It is possible that some sites may not be appropriate for the ABWR design because they could introduce vulnerabilities into the ABWR design that were not taken into account in the Design Certification process. For each site, the COL applicant must provide a site-specific PRA-based analysis to help determine if the ABWR design has any vulnerabilities to previously unanalyzed external events applicable to the site (e.g., river flooding or soil liquefaction from seismic events).

Human reliability analyses (HRAs) of the ABWR design show that it is not particularly sensitive to operator errors during operation in Modes 1 and 2. This is true, in part, because of the multitude of paths by which water can be provided to the core and the inherent attributes of the design (in most sequences of actions, it takes a long time before an operator needs to make a critical decision, if

such a decision is needed at all). GE conducted a sensitivity analysis to investigate the influence of variations in the PRA-modeled human error rates of the ABWR core damage frequency estimate. The analysis suggests that, while there is little room for reducing core damage frequency by improving human performance, core damage frequency can increase if human performance significantly degrades. The potential increase in core damage frequency appears to be about two orders of magnitude above the base case frequency under an assumption that all human error probabilities are simultaneously increased by a factor of 30. However, such a magnitude of increase is unrealistic because the human error probabilities used in the ABWR human performance analyses were either screening values or reasonable values for the actions defined based on previous HRAs for existing PRAs. Even though some recovery actions (such as offsite power and emergency ac) were not included in this analysis, the results of the sensitivity analysis provide a proper indication of the ABWR tolerance of human errors.

Since the ABWR design was not detailed in a number of areas important to evaluating human actions and potential errors (e.g., control room design or plant-specific emergency procedures), GE's HRA was essentially a scoping analysis, based largely on a generalization of results from previous HRAs (which reflect conventional BWR human-machine interface designs) and the use of screening-type human error probabilities collected from various sources. GE contends that this treatment is conservative for the ABWR because of the significant improvements envisioned for the ABWR human-machine interface design relative to earlier designs. However, the validity of the scoping analysis for the as-built ABWR design will need to be confirmed as part of the implementation of the detailed control room design process. This process and associated ITAAC/DAC are described in Chapter 18 of this report. The focus of that effort with regard to the HRA will be on confirming that the final control room design has not introduced any human engineering deficiencies that would significantly increase the error rates for human actions modelled in the HRA or the potential for additional, risk-significant errors not modelled in the HRA.

Every nuclear power plant PRA is incomplete to some extent. Ordinarily, a PRA is performed on a plant for which the site is known, the equipment has been procured, and the plant is nearly or completely built. For the ABWR PRA, the PRA practitioners had to develop their models using a design that lacks many of the details available for an existing plant. The lack of detail was recognized by the staff as well as by GE. For this reason, the staff developed several processes to which the COL applicant must comply, including (a) the ITAAC process, (b) the reliability assurance process and program (O-RAP and DRAP) that the COL applicant should implement to confirm that the as-built plant conforms to the assumptions of the ABWR PRA, and (c) interface items that the COL applicant must address in its application for a COL. To help confirm that the assumptions in the PRA are realized in the as-built design, GE provided a systematic list of SSCs that are to be included in the COL applicant's RAP, PRA-based insights into the ITAAC, and a systematic list of safety insights derived from the ABWR PRA that will be passed on to future COL applicants. One of the significant benefits of having a PRA at early stages in the design is that GE took advantage of PRA insights to improve the final design and provide guidance to COL applicants or holders.

Based on the information provided in the SSAR, this design has achieved a significant reduction in expected core damage frequency and risk compared to operating plant PRA results. The staff compared the numerical results of internal events in the ABWR PRA to the Commission's safety goals and found that the ABWR design meets each safety goal.

As part of its investigation of the ABWR design, the staff endeavored to determine if a balance had been achieved between the prevention of accidents and accident mitigation capabilities. The staff concludes that the design has an appropriate balance of prevention and mitigation. Details of this discussion are provided in Section 19.1.3.9.2 of this report.

GE searched for design and procedure improvements that were prudent to include in the ABWR. The staff concludes that the search made by GE was adequate to identify design and procedure vulnerabilities for the ABWR design. Details of the design improvements motivated by the ABWR PRA are discussed in Section 19.1.3.2.3 of this report.

The staff believes that the ABWR PRA is capable of supporting pre- and post- certification activities such as ITAAC, RAP, and TS. The PRA can be modified to include site-specific design details for areas outside the design certification such as the ultimate heat sink.

19.1.3.2 Level 1 — Internal Events

19.1.3.2.1 Dominant Accident Sequences

GE estimated the total core damage frequency from internal events for the ABWR design to be 1.6E-7 per year. The internal events initiators that contribute the most to core damage frequency are loss of offsite power, SBO, and loss of feedwater/isolation of the vessel (See

- Fire doors generally are not considered to be capable of holding back a large head of water.

- If a watertight door is physically shut but not "dogged," it will not alarm to indicate it is incapable of holding back a flood inside the door.

- The service water system and the CWS are assumed to be designed and located so that they cannot gravity feed to the plant.

- The ACIWA system can provide water to the core or spray the drywell in the event of a catastrophic internal flood. Manual valves to direct the flow to either the core or to the drywell are located in the reactor building and can be operated successfully following an internal flood.

19.1.3.3.3.5 Insights Into Human Reliability and Important Human Actions

Although postulated floods can be mitigated from a risk perspective with few operator actions, because of the inherent ABWR flooding capability (the frequency of internal floods leading to core damage without taking any credit for operation action is still quite low), timely implementation of the following operator actions can limit potential flood damage:

- Isolation of flood sources following detection by sump pump operation and alarms or floor water-level detectors (for floods in the turbine building, the operator should attempt to isolate the leak and shut down the plant without losing condenser vacuum to avoid a "turbine trip without bypass" scenario)

- Closure of watertight doors to prevent damage to equipment in more than one safety division

- Opening of certain nonwatertight doors or hatches to divert water from safety-related equipment.

19.1.3.3.3.6 Combined License Applicant Action Items

GE has identified COL Action Items that define the actions derived from performing the ABWR internal flood analysis that the COL applicant needs to perform or complete. These actions are detailed in SSAR Section 19.9. The staff finds these COL Action Items to be acceptable.

19.1.3.3.3.7 Insights From Uncertainty, Importance, and Sensitivity Analyses

The ABWR internal flooding analysis methodology made bounding assumptions to simplify the task of evaluating floods. This resulted in an evaluation that cannot readily be manipulated to provide uncertainty, importance, or sensitivity insights because of its internal biases. Therefore, GE did not perform any uncertainty, importance, or sensitivity analyses on its internal flooding analysis nor did the staff require these analyses to be performed. GE identified important design features through engineering judgement. The staff finds this approach to be acceptable.

19.1.3.3.4 External Floods

In SECY-93-087, the staff identified the need for a site-specific probabilistic safety analysis and analysis of external events. GE did not perform an analysis (PRA or bounding) of the capability of the ABWR design to withstand external flooding. Instead, GE assumed that the ABWR standard design would be sited such that its grade level would be 30.5 cm (1 ft) higher than the probable maximum flood level as stated in Section 2.6.2 of the SSAR. However, estimates of the return periods of river floods at various nuclear power plant sites that would exceed the probable maximum flood level range from probable to very improbable. For some sites where the return period of large floods is high, the ABWR design may have vulnerabilities to external flooding.

Therefore, the staff will require, where applicable to the site, that the COL applicant perform a site-specific PRA-based analysis for external flooding to search for site-specific vulnerabilities.

19.1.3.4 Operation in Modes Other Than Full Power and Startup — Level 1

This section details the staff's safety insights drawn from the review of the ABWR shutdown heat-removal reliability study performed by GE. Although the staff found that the most significant events to date have occurred at pressurized water reactors (PWRs), the potential vulnerability of BWR plants to shutdown and low-power events cannot be ignored. GE submitted a shutdown risk evaluation of the ABWR design (SSAR Appendix 19Q). The evaluation covered Modes 3 (hot shutdown), 4 (cold shutdown), and 5 (refueling). It included all aspects of the nuclear steam supply system (NSSS), containment, and all systems that support the NSSS and containment. It did not address fuel handling outside the primary containment or fuel storage in the spent fuel pool.

The evaluation covered important aspects of draft NUREG-1449, "NRC Staff Evaluation of Shutdown and Low Power Operation," such as decay heat removal (DHR), inventory control, containment integrity, electrical power, reactivity control, and instrumentation. The

analysis examined 70 loss-of-power and more than 100 loss-of-DHR precursor events at operating BWRs. For new features of the ABWR design, GE developed a failure-modes-and-effects-analysis to determine if the new features would introduce additional shutdown vulnerabilities. GE performed a detailed reliability study of the ABWR DHR function. This study included fault and event trees for all DHR and make-up systems. The analysis separately investigated fire and flooding at shutdown, along with the potential effect of increased maintenance of important equipment.

The staff finds that the ABWR design includes enhanced features that reduce risk during shutdown operations when compared with operating BWRs. These features, including three independent RHR divisions, three EDGs, an ACIWA system, an alternate onsite CTG, and proper plant electrical and physical separation and layout, specifically address the more risk-significant operations during shutdown identified in NUREG-1449. GE provided appropriate safety guidance for effective outage planning and control and provided TS to ensure adequate systems are available to respond to events that may occur during shutdown. Implementation of these recommendations by a COL applicant will be reviewed by the staff.

The staff concludes, based on previous shutdown analyses (both international and U.S. operating reactors) and the ABWR Shutdown Risk Evaluation, that the chances of a core damage event occurring when in Modes 3, 4, or 5 is probably on the same order of magnitude as that of internal events occurring in Modes 1 and 2.

19.1.3.4.1 Dominant Accident Sequences

GE and the staff determined that it would not be useful to attempt to identify dominant accident sequences during Modes 3, 4, and 5. This is because, among all possible plant shutdowns and even on a minute-by-minute basis during any shutdown, the plant configuration could and probably would change. During each of these different configurations, one could conceivably have different dominant sequences and therefore different insights. Because of this, no dominant sequences based on the ABWR Shutdown Risk Evaluation were identified. NUREG-1449 identified that the majority of shutdown precursors and actual shutdown events were caused by human error. Operating, administrative, and emergency procedures as well as aspects of the ABWR design that minimize the chances of human error are discussed below.

19.1.3.4.2 PRA as a Design Tool

GE made no design changes specifically based on the ABWR shutdown risk evaluation. However, it did develop procedural guidance for outage planning and did develop for COL applicants a short list of acceptable system configurations, minimum combinations of systems to ensure adequate shutdown safety margins, when in Modes 3, 4, and 5. This guidance is located in SSAR Section 19.Q.7.9, Tables 19Q-3 through 19Q-5 and is repeated in Table 19.1-9 in this report. The tables were developed based on a single initiating event during shutdown (the failure of the operating DHR division), but are valid for initiating events during shutdown including loss of offsite power and the loss of the operating service water division.

19.1.3.4.3 Vulnerabilities

The staff believes that the results of the ABWR shutdown risk evaluation provide the information needed to decide if there are shutdown vulnerabilities and whether operation in modes other than full power represent a disproportionate risk in the ABWR. GE did not identify any shutdown vulnerabilities. With the use by a COL applicant of the tables (and accompanying or similarly acceptable methodology) that define sets of equipment that should remain operable for the ABWR to meet GE's proposed goal for conditional core damage frequency, 1E-5 given the loss of a DHR train, when in Modes 3, 4, and 5, the staff finds that operation of the ABWR in Modes 3, 4, and 5 does not represent a disproportionate risk. In SSAR Appendix 19Q.9, GE has investigated whether the new features in the ABWR design might have introduced vulnerabilities when in modes other than full power. GE concluded that they did not introduce new vulnerabilities, and the staff concurs with GE's conclusion. The staff reviewed the ABWR shutdown evaluation and found no unreported shutdown vulnerabilities.

19.1.3.4.4 Plant Features and Operator Actions Important to Risk

A detailed list of ABWR features that are important to risk in Modes 3, 4, and 5 are provided in Tables 19Q.4-1 in the SSAR. The following list outlines those areas of the ABWR design that are important to maintaining risk during shutdown operations at a low level.

<u>Features and Actions Minimizing Loss of DHR</u>

- Having three divisions of RHR that are physically separated lowers the frequency of loss of DHR.

procedures to provide core and spent fuel cooling capability and mitigative actions during CRD replacement with fuel in the vessel. GE has included this COL action item in SSAR Amendment 34 and the staff finds it to be acceptable.

19.3.3.2.2 Alternate Reactor Inventory Control Feature

The ABWR design includes a non-safety-related feedwater and condensate system, consisting of three electric pumps and associated piping, that can be used as an alternate means for make-up during shutdown operation. The CRD pump can also be used to provide inventory control during shutdown by injecting water from the condensate storage tank to the RPV through the FMCRD system. An ACIWA system is also available to supply make-up water to the RPV if no ECCS make-up water is available.

The staff finds these provisions acceptable and concludes that GE has sufficiently addressed the concerns in NUREG-1449 related to alternate make-up capability to provide core decay heat removal. The alternate inventory control features using the feedwater, the condensate system, and the CRD pump will provide alternate core cooling upon loss of normal RHR capability. The staff also finds that an ACIWA system will further enhance the capability of the ABWR to maintain core cooling in the event that no ECCS make-up is available.

19.3.3.3 Containment Integrity

During refueling of the ABWR, the primary containment head is removed and cannot be readily repositioned to restore containment integrity. This is also the case for operating BWR plants with Mark I and II containments. NUREG-1449 stated that BWR secondary containments were judged unlikely to prevent an early release following initiation of boiling with an open RCS or during potential severe-core-damage scenarios. This is also the case for the ABWR.

In NUREG-1449, the staff evaluated the need to reestablish containment integrity for all operating plants under shutdown conditions. Based on operating experience, thermal-hydraulic analyses, and PRA assessments, it was concluded that containment integrity under some shutdown conditions may be necessary for pressurized water reactor (PWR) plants. However, this conclusion was not reached for BWR plants. This is a result in part, of the decreased frequency and significance of precursor events involving reduction in reactor vessel level or loss of RHR (or both) in BWRs as compared to PWRs. In addition, BWRs do not enter a midloop operating condition as do PWRs.

In NUREG-1449, the staff stated that operating BWR alternate DHR methods provide significant depth and diversity. For these reasons, the staff concluded that loss of RHR in BWRs during shutdown is not a significant safety issue as long as the equipment (pumps, valves, and instrumentation) needed for these methods is operable and clear procedures exist for applying the methods. As discussed in Sections 19.3.3.1, 19.3.3.1.1, and 19.3.3.2 of this report, GE provided design features to minimize the risk from shutdown events and ensure the availability of DHR and reactor inventory. GE stated that ABWR TS required that secondary containment automatically be isolated on high radiation from a radiological boundary breach or fuel handling accident. Also, procedures should be developed by the COL applicant to ensure that (1) the primary containment is available during Modes 3 and 4 (if appropriate), and (2) the secondary containment can be maintained functional as required, especially during higher-risk evolutions.

Based on the conclusions reached in NUREG-1449 and the improvements, beyond that of operating BWRs, provided in the ABWR design, the staff concludes that additional requirements are not necessary for the primary containment. The requirements to isolate secondary containment on high radiation and fuel-handling accidents, and procedures to ensure the availability of secondary containment during high-risk evolutions could contribute to the mitigation of a low-power and shutdown event.

19.3.3.4 Electrical Power

In NUREG-1449, the staff concluded that the availability of electrical power is vital to maintaining shutdown cooling. A loss of power could range from the complete loss of ac power to the loss of a dc bus or an instrument bus. Loss of electrical power generally leads to other events, such as a loss of SDC.

The staff reviewed the design for the electrical system described in SSAR Section 19.Q.4.4 of the ABWR PRA Shutdown Risk Evaluation Final Report. The ABWR electrical system design includes three diesel generators — one diesel generator for each safety division. A non-safety-related combustion gas turbine is an alternate means of supplying power. The combustion gas turbine can start a feedwater or other pump for DHR or inventory make-up, if required upon a loss of offsite power and diesel generator failure.

Two independent offsite power sources, three unit auxiliary transformers powering three Class 1E and non-1E buses, and four safety divisions of dc power would increase the availability of power for equipment.

"COL Applicant" in the "Safety Issues Index" of SSAR Appendix 19B. The SSAR states that issues are identified for COL action because they pertain to operating personnel issues, operating procedures, and other topics beyond the scope of the ABWR design certification review. SSAR Section 19B.1.1 lists specific documentation the COL applicant is to provide for resolution of such issues.

GE identified this issue for COL applicant action in the "Safety Issues Index." The staff verified that GE established a COL action item (Item 19-28) in SSAR Table 1.9-1 to address unresolved generic and TMI safety issues. This approach is acceptable to the staff. The staff will review the COL applicant's proposed resolution of this issue on a case-by-case basis.

20.4.85 Issue III.D.1.1: Radiation Protection -- Radiation Source Control - Primary Coolant Sources Outside the Containment Structure

Refer to the evaluation of 10 CFR 50.34(f)(2)(xxvi) in Section 20.5.38 of this report.

20.4.86 Issue III.D.3.3: Radiation Protection -- Worker Radiation Protection Improvement - Inplant Radiation Monitoring

Refer to the evaluation of 10 CFR 50.34(f)(2)(xxvii) in Section 20.5.39 of this report.

20.4.87 Issue III.D.3.4: Radiation Protection -- Worker Radiation Protection Improvement - Control Room Habitability

Refer to the evaluation of 10 CFR 50.34(f)(2)(xxviii) in Section 20.5.40 of this report.

20.5 10 CFR 50.34(f), Additional TMI Requirements

This section addresses staff evaluation of paragraphs (1)(i) through (3)(vii) of 10 CFR 50.34(f).

20.5.1 10 CFR 50.34(f)(1)(i): Consideration of Degraded or Melted Cores in Safety Review - Rulemaking Proceeding on Degraded Core Accidents (TMI Item II.B.8), "Design Alternatives from PRA"

Paragraph (1)(i) of 10 CFR 50.34(f) requires the applicant to "perform a plant/site specific probabilistic risk assessment, the aim of which is to seek such improvements in the reliability of core and containment heat removal systems as are significant and practical and do not impact excessively on the plant."

20.5.1.1 Introduction

GE has made extensive use of the results of the PRA to arrive at a final ABWR design. As a result, the estimated core damage frequency and risk calculated for the ABWR is very low both relative to operating plants and in absolute terms. The low core damage frequency and risk for the ABWR is a reflection of GE's efforts to systematically minimize the effect of initiators or sequences that have been important contributors to core damage frequency in previous BWR PRAs. This has been done largely through the incorporation of a number of hardware improvements in the ABWR design. These include the provision of: three separated divisions of ECCSs, a diverse and independent combustion gas turbine capable of providing ac power to any of the three divisions, an ac-independent water addition system, and an FMCRD system as a backup to the hydraulic drive system. Several improvements have also been incorporated in the ABWR design to mitigate the consequences of a core damage event, including inerting of the containment atmosphere, inclusion of a lower drywell flooder system and a containment overpressure protection (vent) system, the use of basaltic concrete in the lower drywell, and an increased ultimate pressure capacity. These and additional ABWR design features which contribute to low core damage frequency and risk for the ABWR are discussed further in FSER Section 19.1.

In response to 10 CFR 50.34(f)(1)(i), GE provided an initial evaluation of further ABWR design improvements in a February 25, 1992 submittal. This submittal was based on the original PRA results, and included consideration of risk from both internally and seismically initiated events. Based on this evaluation, GE concluded that none of the design improvements considered were cost beneficial.

The initial evaluation was subsequently revised to reflect the results of the updated Level 1 PRA and containment analyses, and was resubmitted on June 30, 1992. The revised assessment was based on the risk reduction potential for internal events only, in contrast to the original evaluation which considered both internally and seismically initiated events. This more limited scope was a consequence of GE's change in methodology from a quantitative treatment of seismic risk to a qualitative, margins-type analysis of seismic events. The net result of the new analysis was an order of magnitude reduction of estimated risk from severe accidents -- from 0.047 person-Sv to 0.0048 person-Sv (4.7 person-rem to 0.48 person-rem) over a 60-year plant life -- largely due to removal of seismic events from the risk profile. The reduced risk in the revised analysis further strengthened GE's original conclusion that none of the design improvements, beyond

those already incorporated in the ABWR design, were cost beneficial.

In response to staff comments, GE further modified their evaluation of design improvements to include additional discussion of selected design alternatives, further clarification of the basis for risk-reduction estimates, and additional factors in estimating costs for the modifications. The risk estimates were also adjusted to reflect the results of the final Level 2 analysis and the updated offsite consequence calculations performed as part of the Level 3 portion of the PRA. The final evaluation was submitted as SSAR Appendix 19P.

GE's evaluation of potential design improvements was submitted in response to the requirements of 10 CFR 50.34(f)(1)(i). The staff's review of GE's final evaluation of potential ABWR design improvements is presented below.

20.5.1.2 Estimate of Risk for ABWR

20.5.1.2.1 GE Risk Estimates

GE estimated offsite consequences at five different sites, each representing a different geographic region of the U.S. Offsite consequences were calculated for each release class or case from the Level 2 analysis using the CRAC2 code. The meteorological and population data were obtained from previously developed information contained in NUREG/CR-2239, "Technical Guidance for Siting Criteria Development." The source terms were determined using the MAAP code for each of the release categories as discussed in Section 19.1 of the FSER. The results of the five sets of consequence calculations were averaged together, to represent a typical site in the U.S.

GE's estimate of the cumulative offsite risk to the population within 80 km (50 miles) of the site is provided in SSAR Table 19P-1. The total cumulative exposure calculated by GE is about 0.003 person-Sv (0.3 person-rem), assuming a 60-year plant life. The extremely small level of risk calculated by GE is primarily due to the low estimated core damage frequency for the ABWR (1.6E-7 per reactor year). As a case in point, even if all core damage accidents resulted in the worst release, based on GE's core damage frequency estimates for internal events, the total exposure would only be about 0.3 person-Sv (30 person-rem).

As a result of the low estimated core damage frequency and associated risk levels for the ABWR, any potential modifications which cost more than a few dollars would not be cost-effective, even if the design modification were to totally eliminate the severe accidents or their consequences.

The staff notes that the frequencies of core damage accidents and release bins on which GE based its evaluation of design alternatives are slightly different than those reported in SSAR Section 19D.5. However, these differences are minor and would not alter the essential conclusions of the analysis.

20.5.1.2.2 Staff Review of GE's Risk Estimates

The staff independently estimated the risk associated with severe accidents in the ABWR. A comparison of GE and staff estimates of the person-Sv (person-rem) exposure for each of GE's release classes is provided in FSER Table 20.5.1-1 for internally initiated events. GE's estimates are based on the use of the MAAP and CRAC2 computer codes, and meteorology for five different sites, as described previously. The staff estimates of person-Sv (person-rem) are based on use of the 50th percentile source terms developed during the initial staff review of the ABWR (FSER Table 20.5.1-2), the MACCS offsite consequence code, and meteorology for the Zion site. The staff estimates of the frequency of occurrence of each release class are as reported in FSER Section 19.1.

The GE and staff estimates of person-Sv (person-rem) exposure per event are generally consistent for the large release classes (Cases 7, 8, and 9). The staff's dose estimate is significantly higher for vented scenarios (Case 1) due to the higher fission product release fractions used in the staff's assessment. Similarly, the staff's estimate is much lower for sequences with normal containment leakage (NCL) due to a significantly smaller staff source term for this case. The differences between staff and GE estimates for both these release classes are insignificant, however, since these release classes do not contribute appreciably to total risk.

The estimated total risk over a 60-year reactor operating lifetime is extremely small in both the GE and staff assessment. GE's analysis indicates a total dose of about 0.003 person-Sv (0.3 person-rem) over the 60-year period. The staff's estimate is about 0.01 person-Sv (1 person-rem). The difference is due largely to an increased frequency of early releases in the staff assessment to account for: (1) the contribution from unisolated LOCAs outside containment, and (2) an increased probability of early containment failure from direct containment heating. It can be noted that total risk is dominated by events which lead to early containment failure, and containment bypass. This is consistent with the results from PRAs for operating plants.

Table 20.5.1-1a Comparison of GE and staff adjusted offsite consequences (person-Sv)

Case*	GE Estimates 1/				Staff-Adjusted Estimates			
	Frequency	Person-Sv	Person-Sv per 60 y	Fraction	Frequency 2/	Person-Sv 3/	Person-Sv per 60 y	Fraction
NCL	1.3E-7	96	.00075	.28	1.34E-7	.1	.000008	<.01
Case 1	2.1E-8	1.4E2	.00018	.07	2.08E-8	1.4E3	.0017	.13
Case 7	3.9E-10	2.7E4	.00063	.23	3.6E-10	1.6E4	.00035	.03
Case 8	4.1E-10	3.2E4	.00079	.29	3.6E-9 4/	4.5E4	.0097	.77
Case 9	1.7E-10	3.3E4	.00034	.13	3.3E-10	4.5E4 5/	.00089	.07
Total	1.6E-7		.00269	1.0	1.6E-7		.0126	1.0

Table 20.5.1-1b Comparison of GE and staff adjusted offsite consequences (person-rem)

Case*	GE Estimates 1/				Staff-Adjusted Estimates			
	Frequency	Person-Rem	Person-Rem per 60 y	Fraction	Frequency 2/	Person-Rem 3/	Person-Rem per 60 y	Fraction
NCL	1.3E-7	9600	.075	.28	1.34E-7	100	.0008	<.01
Case 1	2.1E-8	1.4E4	.018	.07	2.08E-8	1.4E5	.17	.13
Case 7	3.9E-10	2.7E6	.063	.23	3.6E-10	1.6E6	.035	.03
Case 8	4.1E-10	3.2E6	.079	.29	3.6E-9 4/	4.5E6	.97	.77
Case 9	1.7E-10	3.3E6	.034	.13	3.3E-10	4.5E6 5/	.089	.07
Total	1.6E-7		0.269	1.0	1.6E-7		1.26	1.0

Notes:

* For case description, refer to Table 20.5.1-2.

1/ Based on information reported in SSAR Table 19P-1.

2/ Based on GE's containment event tree end state frequencies with staff corrections.

3/ Based on staff 50th percentile source terms (see Table 20.5.1-2) and use of MACCS consequence code with Zion site meteorology.

4/ Staff frequency estimate includes: (1) contribution from unisolated LOCAs outside containment, and (2) increased probability of early containment failure from direct containment heating.

5/ Based on the staff's source term estimate for Case 8.

Table 20.5.1-2 Cesium and Iodine release fractions, as estimated by the staff and GE

	GE Case Identifier	Staff's Estimate 5th	Staff's Estimate 50th	Staff's Estimate 95th	GE's Estimate
Cesium	NCL	2.1×10^{-11}	3.2×10^{-9}	3.9×10^{-8}	5.1×10^{-5}
	Case 1	2.7×10^{-6}	2.7×10^{-4}	5.3×10^{-2}	1.3×10^{-5}
	Case 7	6.6×10^{-6}	2.4×10^{-3}	1.4×10^{-1}	9.9×10^{-2}
	Case 8	0.002	0.06	0.75	0.25
	Case 9	8.3×10^{-4}	7.8×10^{-3}	1.7×10^{-1}	0.36
Iodine	NCL	3.4×10^{-11}	2.3×10^{-6}	3.8×10^{-4}	3.8×10^{-6}
	Case 1	8.5×10^{-6}	9.2×10^{-4}	6.1×10^{-2}	1.5×10^{-7}
	Case 7	4.7×10^{-4}	9.7×10^{-2}	3.2×10^{-1}	8.9×10^{-2}
	Case 8	0.007	0.19	0.69	0.19
	Case 9	0.002	0.10	0.16	0.37

Case	Description
NCL	Normal containment leakage, no containment failure.
Case 1	Fission products scrubbed by suppression pool before release, includes the "venting" sequences.
Case 7	Late containment failure due to overpressurization, spray available, no suppression pool scrubbing.
Case 8	Early containment failure, no suppression pool scrubbing.
Case 9	Late containment failure due to overpressurization, no spray, no suppression pool scrubbing.

As discussed below, the staff based its assessment of risk-reduction potential for the various ABWR design improvements on the staff estimate of risk for internally initiated events, that is, 0.01 person-Sv (1 person-rem). However, the validity of the conclusions of this analysis were tested by considering the uncertainties in core damage frequency estimates, as well as the potential frequency of core damage due to external events.

20.5.1.3 Identification of Potential Design Improvements

20.5.1.3.1 List of Potential Design Improvements

GE identified a set of potential design improvements for the ABWR based on a survey of previous industry- and NRC-sponsored studies of preventative and mitigative features which address severe accidents. Through this effort GE developed a composite list of 68 potential design improvements, organized into 14 general categories. These categories and many of the design improvements are the same as considered for the General Electric Standard Safety Application Report (GESSAR) II design. The resulting list of potential design improvements for the ABWR is presented in SSAR Table 19P-3.

GE eliminated certain design improvements from further consideration on the basis that they are either already incorporated into the ABWR design, or not applicable to the ABWR design. Examples of design improvements already included in the design are: improved low-pressure injection system (fire pump), RWCU decay heat removal, low flow unfiltered vent, and combustible gas control (inerted containment). On the basis of this screening, 21 potential design improvements covering 12 of the 14 general categories were retained for further consideration. The set of design improvements selected for further evaluation is listed in Table 20.5.1-3, and summarized in Section 20.5.1.3.2 of this report.

The staff and its contractor, Brookhaven National Laboratory (BNL), have reviewed the set of potential design improvements identified by GE (SSAR Table 19P-3) and find it to be comprehensive. The list includes all improvements identified as part of the GESSAR II review, and the NRC Containment Performance Improvement (CPI) program. The staff notes that the set of design improvements is not all-inclusive, in that additional, perhaps less expensive design improvements can always be postulated. However, the staff concludes that the benefits offered by any additional modifications would not likely exceed those for the modifications evaluated. The staff also concludes that the costs of alternative improvements would not likely be less than that of the lowest cost improvements evaluated, when the subsidiary costs associated with maintenance, procedures, and training are considered. On this basis, the staff concludes that the set of potential design improvements identified by GE is acceptable.

The set of design improvements selected for further evaluation also appears to be reasonable. The staff notes that the improvements considered include a filtered containment vent, and flooded rubble bed core retention device, which are two improvements specifically cited in NUREG-0660 for evaluation as part of TMI Item II.B.8. A modification intended to delay the time of reactor vessel failure through the use of alternative materials for the bottom head penetration piping was also considered by GE. This modification was instigated by the results of recent analyses of reactor vessel bottom head failure as documented in draft NUREG/CR-5642.

Finally, it should be noted that certain features of several of the improvements selected for further evaluation have been or will be incorporated as part of the ABWR design, independent of this evaluation of design improvements. For example, severe accident EPGs or accident management guidelines (AMGs) will be implemented by the COL applicant as part of its accident management program, as discussed in FSER Section 19.2, and much of the benefits of improved maintenance procedures or manuals will be achieved through the COL applicant's reliability assurance program, as discussed in Section 19.1.3.7 of this report.

20.5.1.3.2 Description of Design Improvements

A description of the design improvements selected by GE for cost-benefit evaluation is provided in SSAR Sections 19P.3 and 19P.4, and summarized below.

- Severe accident EPGs or AMGs - extend the EPGs and EOPs to address arrest of a core melt, emergency planning, radiological release assessment and other areas related to severe accidents. This modification would lead to increased reliability of manual actions in response to core-damage events.

- Computer-aided instrumentation - provide artificial intelligence-based improvements to plant status monitoring, including human-engineered displays of important variables in the EPGs and AMGs, and procedural options for the operator to evaluate during severe accidents. This modification would lead to increased reliability of manual actions to prevent core damage.

Table 20.5.1-3 Potential Design Improvements and Associated Costs (Provided by GE)

	Modification	Estimated Cost ($M)	Person-Sv (Person-Rem) Averted		Cost($M)/Person-Sv (Person-Rem) Averted	
1.	**Accident Management**					
1a.	Severe accident EPGs	0.60	0.00015	(0.015)	4,000	(40)
1b.	Computer-aided instrumentation	0.60	0.00010	(0.01)	>4,000	(>40)
1c.	Improved maintenance procedures/manuals	0.30	0.00016	(0.016)	1,880	(18.8)
2.	**Decay Heat Removal**					
2a.	Passive high pressure system	1.75	0.00138	(0.138)	1,270	(12.7)
2b.	Improved depressurization	0.60	0.00042	(0.042)	1,430	(14.3)
2c.	Suppression pool jockey pump	0.12	0.00002	(0.002)	>4,000	(>40)
2d.	Safety-related condensate storage tank	1.0	0.00010	(0.01)	>4,000	(>40)
3.	**Containment Capability**					
3a.	Larger volume containment	8.0	0.00150	(0.15)	>4,000	(>40)
3b.	Increased containment pressure capacity	12.0	0.00020	(0.02)	>4,000	(>40)
3c.	Improved vacuum breakers	0.10	0.0000003	(0.00003)	>4,000	(>40)
3d.	Improved bottom head penetration design	0.75	0.00057	(0.057)	1,320	(13.2)
4.	**Containment Heat Removal**					
4a.	Larger volume suppression pool	8.0	0.000002	(0.0002)	>4,000	(>40)
5.	**Containment Atmosphere Mass Removal**					
5.a	Low-flow filtered vent	3.0	0.00014	(0.014)	>4,000	(>40)
7.	**Containment Spray Systems**					
7a.	Drywell head flooding	0.10	0.00060	(0.06)	1,700	(1.7)
8.	**Prevention Concepts**					
8a.	Additional service water loop	6.0	0.00016	(0.016)	>4,000	(>40)
9.	**AC Power Supplies**					
9a.	Steam driven turbine generator	6.0	0.00052	(0.052)	>4,000	(>40)
9b.	Alternate pump power source	1.2	0.00069	(0.069)	1,740	(17.4)
10.	**DC Power Supplies**					
10a.	Dedicated RHR dc Power Supply	3.0	0.00069	(0.069)	>4,000	(>40)
11.	**ATWS Capability**					
11a.	ATWS-sized vent	0.30	0.00030	(0.03)	1,000	(10)
13.	**System Simplification**					
13a.	Reactor building sprays	0.10	0.00017	(0.017)	5,900	(5.9)
14.	**Core Retention Devices**					
14a.	Flooded rubble bed	18.8	0.00001	(0.001)	>4,000	(>40)

- Improved maintenance procedures or manuals - provide improved maintenance manuals and additional information on the components important to the risk of the plant within the GE scope of supply. These manuals and information would lead to increased reliability of important equipment.

- Passive high pressure system - add an isolation condenser-type high pressure system for removing decay heat from both the core and containment. The benefit of this system would be equivalent to an additional RCIC system and containment heat-removal system.

- Improved depressurization - provide manually controlled, seismically protected air operators to permit manual depressurization in the event of loss of dc control power or control air events. Improved depressurization would reduce the threat of containment failure due to high pressure melt ejection, and allow more reliable access to low-pressure systems.

- Suppression pool jockey pump - add a small, ac-independent makeup pump to provide low-pressure decay heat removal from the reactor pressure vessel using suppression pool water as the source. This modification would have a benefit similar to that provided by the ac-independent water addition mode of RHR (fire water), but without the associated long-term containment inventory concerns.

- Safety-related condensate storage tank - upgrade the structure of the condensate storage tank such that it would be available to provide makeup to the reactor following a large seismic event. This would enhance core injection capabilities in seismic events, by providing an alternative to the suppression pool as a source of water for injection.

- Larger volume containment - increase the volume of containment by a factor of two. This would reduce the peak pressures associated with energetic events, thereby reducing the potential for drywell head failure, and would also reduce the rate of long-term containment pressurization, thereby delaying the time of fission product release.

- Increased containment pressure capacity - increase the ultimate pressure capacity of containment (including seals) to a level at which all release modes except normal containment leakage are eliminated.

- Improved vacuum breakers - add a second vacuum breaker valve in each of the eight drywell-to-wetwell vacuum breaker lines to make these valves redundant. This modification would reduce the potential for suppression pool bypass due to stuck-open or leaking vacuum breaker valves.

- Improved bottom head penetration design - change the transition piece (used to connect the stainless steel RPV drain line to the RPV) from carbon steel to a material with a higher melting point, such as inconel. Also, establish external welds or restraints on the CRDs external to the vessel so that the drives would not be ejected following failure of the internal welds. This modification would delay the time of reactor vessel failure by several hours, thereby increasing the potential to arrest core damage in the vessel, but may also increase the potential for gross failure of the lower head.

- Larger volume suppression pool - increase the size of the suppression pool to provide reduced pool heatup rates. This modification would reduce the frequency of core melt from Class II sequences (loss of containment heat removal), and ATWS sequences by providing additional time for operator actions and recovery of heat removal systems.

- Low-flow filtered vent - add a filter system external to the containment to further reduce the magnitude of radioactive releases via containment venting. The system would be similar to the multi-venturi scrubbing systems implemented in some plants in Europe. The system would provide fission product scrubbing beyond that presently offered by the suppression pool, but would not affect releases due to drywell head failure and containment bypass sequences.

- Drywell head flooding - provide an additional line to permit intentional flooding of the upper drywell head using the existing fire water additional system. Drywell head flooding would cool the drywell head seal and provide fission product scrubbing in the event of drywell head leakage. Instrumentation and controls to permit manual control from the control room were considered part of this modification.

- Additional service water loop - provide an additional service water cooling loop (pump and heat exchanger) to improve the overall reliability of the service water network. This cooling loop would be capable of removing heat from any one of the three divisions. This would reduce the frequency of sequences involving failure of injection due to loss of component cooling.

- Steam-driven turbine generator - add a steam-driven turbine generator that uses reactor steam and exhausts to the suppression pool. The benefits of this modifi-

cation would be a further reduction in the frequency of station blackout sequences, similar to that which might be obtained by adding another gas turbine generator.

- Alternate pump power source - provide a separate diesel generator and supporting auxiliaries to power the feedwater or condensate pumps. This modification would remove the reliance of these pumps on offsite power, and permit them to be used as a backup to HPCF and low-pressure core flooder.

- Dedicated dc power supply - provide a separate, diverse dc power source (fuel cell or separate battery) to supply a dc motor-pump combination for RPV and containment cooling. This modification would further reduce the risk from loss of offsite power and station blackout.

- ATWS-sized vent - provide a wetwell vent line capable of passing the steam flow associated with ATWS. The system would be significantly larger than the existing containment overpressure protection system (COPS) design, and manually initiated from the control room. This system would prevent containment overpressure failure in ATWS events, and thereby prevent core damage.

- Reactor building sprays - modify the fire water spray system in the reactor building to spray in areas vulnerable to release. This modification would reduce the risk associated with releases into the reactor building, such as drywell head failures and containment bypass events, but would not impact releases via COPS.

- Flooded rubble bed - provide a bed of refractory pebbles that would be flooded with water. The rubble bed would impede the flow of molten corium to the concrete drywell structures, and increase the available heat transfer area, thereby enhancing debris coolability. This modification would further reduce the potential for core concrete interactions in the ABWR. A major drawback of the modification is that additional experimental testing would be necessary to validate the concept for the ABWR application.

20.5.1.4 Risk Reduction Potential of Design Improvements

20.5.1.4.1 GE Evaluation of Risk Reduction Potential

GE used the reduction in cumulative risk of accidents occurring during the life of the plant as the basis for estimating the benefit that could be derived from plant improvements. Estimates of risk reduction were developed by determining the approximate effect of each modification on the frequency of the various release classes in the PRA. GE's basis for estimating the risk reduction for each design improvement is provided in SSAR Section 19P.4, and summarized in Table 20.5.1-4 of this report.

The staff reviewed GE's bases for estimating the risk reduction associated with the various design improvements. The staff notes that considerable judgement was exercised in estimating the risk reduction potential, but that in general, the rationale and assumptions on which the risk reduction estimates are based (center column of Table 20.5.1-4) are reasonable, and in many cases conservative. However, this is not to say that the estimates of person-Sv (person-rem) averted are conservative, since the staff is not in complete agreement with GE's characterization of baseline risk. For example, the risk-reduction potential for improved vacuum breakers appears to be underestimated in GE's analysis. GE estimates that improved vacuum breakers (addition of a second vacuum breaker valve in series with each of the existing valves) would reduce risk by about 3E-7 person-Sv (0.00003 person-rem). This value is in large part due to significant credit for fission product removal by wetwell sprays (when available), and the failure to account for the impact of the design improvement on bypass scenarios in which sprays are not available. GE's risk-reduction estimate for this improvement would increase by at least three orders of magnitude if just the latter factor was accounted for. Nevertheless, the risk reduction would remain small since the probability of the events involved is on the order of 1E-10 per reactor year.

20.5.1.4.2 Staff Evaluation of Risk-Reduction Potential

In view of the extremely small residual risk for the ABWR, rather than perform an independent assessment of the risk-reduction potential of each ABWR design improvement, the staff used a bounding assumption that each improvement would eliminate all of the risk for the ABWR (0.01 person-Sv (1 person-rem) for the 60-year plant life). This approach tends to overestimate the benefits because the ABWR risk profile reflects contributions from several unique types of sequences (e.g., station blackout, containment bypass, and LOCAs). An individual design improvement would generally reduce or eliminate some of these contributors but would not be effective on others. Moreover, there are numerous and diverse modes of containment failure which must be dealt with to ensure containment integrity in a severe accident. Thus, a carefully selected set of plant improvements would generally be needed, each one acting on particular components of risk, to effectively and significantly reduce total risk.

Table 20.5.1-4 Summary of GE's assessment of risk reduction for candidate design improvements

Potential ABWR design modification	GE's basis for estimating risk reduction	Person-SV (person-rem) averted
Accident Management		
Severe accident EPGs/AMGs	10% reduction in failure rates for manually initiated mitigative actions	0.00015 (0.015)
Computer-aided instrumentation	10% reduction in failure rates for manually initiated preventive actions	0.00010 (0.01)
Improved maintenance procedures/manuals	10% improvement in reliability of HPCF, RCIC, RHR, LPCF	0.00016 (0.016)
Decay Heat Removal		
Passive high pressure system	Equivalent to adding a diverse RCIC and RHR system with 10% unavailability	0.00138 (0.138)
Improved depressurization system	Factor of 2 reduction in depressurization failure rates	0.00042 (0.042)
Suppression pool jockey pump	10% improvement in reliability of low pressure makeup (resulting in 2% reduction in core damage frequency from low pressure sequences	0.00002 (0.002)
Safety-related condensate storage tank	Engineering judgement	0.00010 (0.01)
Containment Capability		
Larger volume containment	Elimination of all containment release modes involving drywell head failure (Cases 3, 6, 7, 8, 9)	0.00150 (0.15)
Increased containment pressure capacity	Elimination of all containment release modes except normal containment leakage	0.00020 (0.02)
Improved vacuum breakers	Elimination of releases from Release Class 2	.0000003 (0.00003)
Improved bottom head penetration design	Factor of 2 increase in the probability of arresting core damage in-vessel	0.00057 (0.057)

Table 20.5.1-4 Summary of GE's assessment of risk reduction for candidate design improvements (continued)

Potential ABWR design modification	GE's basis for estimating risk reduction	Person-SV (person-rem) averted
Containment Heat Removal		
Large volume suppression pool	Elimination of Class II Sequences	.000002 (0.0002)
Containment Mass Removal		
Low-flow filtered vent	Elimination of the risk associated with releases via COPS	0.00014 (0.014)
Containment Spray Systems		
Drywell head flooding	Elimination of drywell head over-temperature failures and reduction in releases from drywell head over-pressure failures	0.00060 (0.06)
Prevention Concepts		
Additional service water Loop	10% increase in reliability of HPCF, RCIC, RHR, LPCF	0.00016 (0.016)
AC Power Supplies		
Steam-driven turbine generator	80% reduction in the diesel generator common mode failure rate	0.00052 (0.052)
Alternate pump power source	Equivalent to adding a diverse RCIC system	0.00069 (0.069)
DC Power Supplies		
Dedicated dc power supply	Factor of 10 increase in RCIC availability in LOOP and SBO sequences	0.00069 (0.069)
ATWS Capability		
ATWS-sized vent	Elimination of risk from ATWS (Case 9)	0.00030 (0.03)
System Simplification		
Reactor building sprays	10% reduction in risk from releases through the reactor building	0.00017 (0.017)
Core Retention Devices		
Flooded rubble bed	Elimination of sequences with core concrete interactions, except those with failure of containment heat removal (1% of Cases 1, 6, and 7)	0.000010 (0.001)

20.5.1.5 Cost Impacts of Candidate Design Improvements

GE determined the approximate costs for each design improvement. The costing methodology and assumptions are described in SSAR Section 19P.1.3. The cost basis for each plant improvement is provided in SSAR Section 19P.5 on an item-by-item basis.

GE stated in the SSAR that the cost estimates represent the incremental costs that would be incurred in a new plant, rather than costs that would apply on a backfit basis. GE also stated that the costs were intentionally biased on the low side, but that all known or reasonably expected costs were accounted for so that a reasonable assessment of the minimum cost would be obtained.

For modifications which reduce core damage frequency, GE reduced the costs of the design improvements by an amount proportional to the reduction in the present worth of the risk of averted onsite costs. Onsite costs considered include replacement power at $.013/kwh differential cost, direct accident costs including onsite cleanup at $2 billion, and the economic loss of the facility at $1.4 billion. The resulting costs for each of the design improvements are provided in Table 20.5.1-3.

The staff reviewed the bases for GE's cost estimates and finds them to be reasonable. For certain improvements, the staff also compared GE's cost estimates with estimates developed elsewhere for similar improvements, even though the bases for some of these cost estimates were different. The staff considered the cost estimates developed as part of: the evaluation of design improvements for GESSAR II (NUREG-0979, Supplement 4), and the review of SAMDAs for Limerick and Comanche Peak (NUREG-0974 and -0775, respectively).

The staff noted a number of inconsistencies in the cost estimates. For example, GE's cost estimates for certain improvements such as improved vacuum breakers ($100,000), modified reactor building sprays ($100,000), and ATWS-sized vent ($300,000) were are considerably less than expected. The costs for certain other improvements was much higher than expected, such as improved bottom head penetration design ($750,000) and flooded rubble bed (approximately $19 million).

It should be noted that only rough approximations of the costs of specific improvements are possible at this time. Large uncertainties exist because detailed designs are not available and because experience with construction and licensing problems that could surface with this type of work is limited. Nevertheless, the staff views GE's approximate cost estimates as adequate, given the uncertainties surrounding the underlying cost estimates, and the level of precision necessary given the greater uncertainty inherent on the benefit side, with which these costs were compared.

20.5.1.6 Cost-Benefit Comparison

A cost-benefit comparison was performed to determine whether any of the potential severe accident design features could be justified. GE's estimates of the cost per person-Sv (person-rem) averted for the various design improvements are presented in Table 20.5.1-3. The GE values are based on the risk- reduction estimates reported in Tables 20.5.1-3, and 20.5.1-4 of this report. The staff analysis is based on the conservative assumption that each design improvement would eliminate all of the residual risk (0.01 person-Sv (1 person-rem) over the 60-year plant life).

Consistent with current NRC practice (NUREG-3568), GE used a screening criterion of $100,000 per person-Sv ($1000 per person-rem) averted to identify whether any of the design improvements could be cost-effective. As shown in Table 20.5.1-3, the potential cost per averted person-rem ranges from about $1.7 million to far-in-excess of $40 million for the various suggested modifications according to the GE evaluation. Thus, this far exceeds the $100,000 per person-Sv ($1000 per person-rem) criterion. On this basis, GE concluded that no additional modifications to the ABWR design are warranted.

The staff's assessment similarly indicates that none of the design improvements approach a level where they could be considered cost-effective, in spite of the significant conservatisms in assessing risk-reduction potential in the staff's analysis. The staff notes that the lowest cost modifications were estimated to cost about $100,000, and realistically would only partially reduce the residual risk for the ABWR. Even though the cost of implementing design improvements in the ABWR may be less than for an existing plant, given that the ABWR has not yet been constructed, relatively large costs are still to be anticipated for many of the design improvements because they would involve first-of-a-kind engineering, and would need to be integrated within the existing design. In addition, the introduction of a new system will trigger a series of related requirements such as incremental training, procedural changes, and possible licensing requirements. These are all legitimate costs that require consideration in a comprehensive cost estimate. The staff concludes that none of the modifications evaluated would be cost-effective given the low residual risk for the ABWR, and the $1000 per person-rem criterion.

The staff has considered the robustness of this conclusion relative to a number of critical assumptions in the analysis as described below. These involve: the effect of uncertainties in estimating core damage frequency, the use of alternative cost-benefit criteria, and the inclusion of external events within the scope of the analysis.

Based on uncertainty analyses performed by GE for the Level 1 portion of the PRA (see FSER Section 19.1.3.2.6), the 95th percentile core damage frequency is 4.5E-7 per reactor year. This is a factor of three higher than the mean value on which the cost-benefit analysis is based, but still very low both compared to operating plants and in absolute terms. Even if the benefits of the various design improvements were re-quantified on the basis of this upper-bound value, none of the improvements would become cost beneficial. This would remain the case even if the cost-benefit criterion was also increased by a factor of 10 to $1 million per person-Sv ($10,000 per person-rem) averted.

If external events are included, the estimate of ABWR risk could be one or possibly two orders of magnitude higher than considered in this analysis. For example, based on the BNL review of GE's original seismic PRA, as documented in the DSER (SECY-91-309), the total risk from internal and seismic events for the 60-year plant life would range from about 0.4 to 2 person-Sv (40 to 200 person-rem) depending on the site population. However, the value for the final ABWR design would be somewhat less since these estimates do not account for plant improvements incorporated in the design subsequent to the original PRA analysis, including upgrading the seismic capability of the diesel-driven fire water pump.

Even assuming the higher of these two risk estimates and complete elimination of all risk, any design modifications or combinations which cost more than $200,000 would not be cost-effective. This would eliminate most of the candidate design modifications from further consideration. Based on the GE analysis, those modifications which were estimated to cost less than $200,000 have a relatively low risk-reduction potential, and would generally eliminate only about 10 percent of the residual risk from internal events. The improvements are also not expected to be effective in eliminating most of the added risk from seismic events. Since the minimum cost of these systems would be about $100,000, none of these improvements are expected to be cost-effective when their actual effectiveness in reducing risk is taken into account.

The staff concludes that with the significant margins in the results of the cost-benefit analysis, the findings of the analysis would be unchanged even considering the above factors.

20.5.1.7 Conclusions

As discussed in Chapter 19.1.3.2.2 of this report, GE has made extensive use of the results of the PRA to arrive at a final ABWR design. As a result, the estimated core damage frequency and risk calculated for the ABWR is very low both relative to operating plants and in absolute terms. The low core damage frequency and risk for the ABWR is a reflection of GE's efforts to systematically minimize the effect of initiators or sequences that have been important contributors to core damage frequency in previous BWR PRAs. This has been done largely through the incorporation of a number of hardware improvements in the ABWR design. These include providing three separated divisions of ECCSs, a diverse and independent combustion gas turbine capable of providing ac power to any of the three divisions, an ac-independent water addition system, and an FMCRD system as a backup to the hydraulic drive system. Several improvements have also been incorporated in the ABWR design to mitigate the consequences of a core damage event, including inerting of the containment atmosphere, inclusion of a lower drywell flooder system and a containment overpressure protection (vent) system, the use of basaltic concrete in the lower drywell, and an increased ultimate pressure capacity. These and additional ABWR design features which contribute to low core damage frequency and risk for the ABWR are discussed further in Section 19.1.3.2.3 of this report.

Because the ABWR design already includes numerous plant features oriented towards reducing core damage frequency and risk, the benefits and risk- reduction potential of additional plant improvements is significantly reduced. This is true for both internally and externally initiated events. For example, the ABWR seismic design basis (0.3g safe shutdown earthquake) has been shown to result in significant ability to withstand earthquakes well beyond the design basis, as characterized by a high confidence with low probability of failure (HCLPF) value of 0.6g. Moreover, with the features already incorporated in the ABWR design, the ability to estimate core damage frequency and risk approaches the limitations of probabilistic techniques. Specifically, when core damage frequencies of one in a hundred thousand or a million years are estimated in a PRA, it is the areas of the PRA where modelling is least complete, or supporting data is sparse or even nonexistent that could actually be the more important contributors to risk. Areas not modelled or incompletely modelled include human reliability, sabotage, rare initiating events, construction or design errors, and systems interactions. Although improvements in the modelling of these areas may introduce additional contributors to core damage frequency and risk, the staff

does not expect that they would be significant in absolute terms.

10 CFR 50.34(f)(1)(i) requires the applicant to perform a plant- or site- specific probabilistic risk assessment, the aim of which is to seek such improvements in the reliability of core and containment heat removal systems as are significant and practical and do not impact excessively on the plant. The staff concludes that the ABWR PRA, and GE's use of the insights of this study to improve the design of the ABWR meets this requirement. The staff concurs with the GE conclusion that none of the potential design modifications evaluated are justified based on cost-benefit considerations. The staff also concludes that it is unlikely that any other design changes would be justified on the basis of person-Sv (person-rem) exposure considerations, because the estimated core damage frequencies would remain very low on an absolute scale.

20.5.2 10 CFR 50.34(f)(1)(ii): System Design – Auxiliary Feedwater System - Auxiliary Feedwater System Evaluation (TMI Item II.E.1.1)

Paragraph (1)(ii) of 10 CFR 50.34(f) requires the performance of an evaluation of the proposed AFWS of PWR plants to include a simplified AFWS reliability analysis using event-tree and fault-tree logic techniques, design review of AFWS, and an evaluation of AFWS flow design bases and criteria.

This requirement is applicable to PWRs only, since a BWR design does not include an AFWS. Therefore, it is not technically relevant to the ABWR design and does not need to be addressed.

20.5.3 10 CFR 50.34(f)(1)(iii):

Measures to Mitigate Small-Break Loss-of-Coolant Accidents and Loss-of-Feedwater Accidents – Commission Orders on B&W Plants - Impact of RCP Seal Damage Following SBLOCA With Loss of Offsite Power (TMI Item II.K.2(16)) and

Measures to Mitigate Small-Break Loss-of-Coolant Accidents and Loss-of-Feedwater Accidents – Final Recommendations of Bulletins and Orders Task Force - Effect of Loss of ac Power on Pump Seals (TMI Item II.K.3(25))

TMI Item II.K.2(16) is applicable to PWRs only and does not need to be addressed for the ABWR, but II.K.3(25) applies to BWRs. Paragraph (1)(iii) of 10 CFR 50.34(f) requires analyses or experiments to determine the consequences at each plant of a loss of cooling water to the reactor recirculation pump seal coolers. Pump seals should be designed to withstand a complete loss of ac power for at least two hours and the adequacy of the seal design should also be demonstrated. The design should prevent an excessive loss of reactor coolant inventory after an anticipated operational occurrence. It is assumed that the loss of ac power constitutes a loss of offsite power.

SSAR Sections 5.4.1 and 1A.2.30 state that the ABWR design features reactor internal pumps (RIPs) that do not require pump shaft seals. During a loss of ac power, the RIPs are shut down automatically, but there are no shaft seals that require restoration of cooling. During its review of this issue, the staff required GE to confirm that the failure of the following systems would not cause a LOCA

- recirculation motor cooling system
- recirculation motor seal purge system
- recirculation motor inflatable shaft seal subsystem.

GE confirmed in SSAR Section 1A.2.30 that an ac failure would temporarily disrupt the operation of these systems, but their failure would not generate a LOCA. Therefore, the staff concludes that GE adequately addressed the requirements of this TMI item for the ABWR design.

20.5.4 10 CFR 50.34(f)(1)(iv): Measures to Mitigate Small-Break Loss-of-Coolant Accidents and Loss-of-Feedwater Accidents – Final Recommendations of Bulletins and Orders Task Force - Report on Overall Safety Effect of PORV Isolation (TMI Item II.K.3(2))

Paragraph (1)(ii) of 10 CFR 50.34(f) requires performance of an analysis of the probability of a SBLOCA caused by a stuck-open PORV of PWR plants. If the probability is a significant contributor to the probability of SBLOCAs from all causes, it also requires a description and evaluation of the effect on SBLOCA probability of an automatic PORV isolation system that would operate when the RCS pressure falls after the PORV has opened.

This requirement is applicable to PWRs only, therefore, it is not technically relevant to the ABWR design and does not need to be addressed.

STP Attachment 5

Nuclear Operating Company

South Texas Project Electric Generating Station 4000 Avenue F – Suite A Bay City, Texas 77414

September 15, 2009
U7-C-STP-NRC-090144

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
One White Flint North
11555 Rockville Pike
Rockville MD 20852-2738

South Texas Project
Units 3 and 4
Docket Nos. 52-012 and 52-013
Response to Request for Additional Information

Attached are revised or supplementary responses to NRC staff questions included in Request for Additional Information (RAI) letter number 124 related to Combined License Application (COLA) Part 2, Tier 2 Chapter 19. The original transmittal letter is U7-C-STP-NRC-090064 dated July 13, 2009. Attachments 1, 2, and 3 contain the revised or supplementary responses to the RAI questions listed below:

19-1 19-3 19-5

Attachment 4 addresses the responses to NRC staff questions included in RAI letter number 189 related to COLA Part 2, Tier 2, Section 7.1, Question 07.01-5.

Attachment 5 addresses the responses to NRC staff questions included in RAI letter number 213 related to COLA Part 2, Tier 2, Section 6.6, Question 06.06-4.

When a change to the COLA is indicated, the change will be incorporated into the next routine revision of the COLA following NRC acceptance of the RAI response.

There are no new or revised commitments in this letter.

If you have any questions regarding these RAI responses, please contact me at (361) 972-7136, or Bill Mookhoek at (361) 972-7274.

STI 32534719

D091
NRO

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 9/15/09

Scott Head
Manager, Regulatory Affairs
South Texas Project Units 3 & 4

dws

Attachments:

1. Question 19-1, Supplement
2. Question 19-3, Revised Response
3. Question 19-5, Supplement
4. Question 07.01-5
5. Question 06.06-4

RAI 19-3

QUESTION:

Contributions to LRF and CCFP from severe accidents during low power or shutdown operations were not included in the ABWR SSAR or in the STP 3 and 4 FSAR. More recent design certification PRAs have shown that such scenarios are significant and sometimes dominant contributors to LRF and CCFP. Please discuss the impacts on LRF and the overall CCFP from low power and shutdown scenarios for STP 3 and 4. In addition, please explain whether or not the deletion of the Flammability Control System, including the recombiners, from the STP 3 and 4 design, affects the consideration of hydrogen combustion during the startup/shutdown periods when the containment may not be inerted.

REVISED RESPONSE:

The following information revises the response submitted as Attachment 3 to the letter from Mark McBurnet to Document Control Desk, "Response to Request for Additional Information," dated July 13, 2009, U7-C-STP-NRC-090064.

DCD Appendix 19QB, which is Incorporated by Reference in the STP 3 and 4 COLA, discusses potential offsite releases during shutdown. The DCD also considered containment integrity in evaluating the risk during low power and shutdown conditions in DCD Chapter 19Q.4.3. There are no departures that affect the referenced discussions in Appendix 19Q on containment integrity during shutdown. Further discussion of the ABWR containment and offsite releases during shutdown accident scenarios is provided in DCD Section 19L.8 which is Incorporated by Reference in the STP 3 and 4 COLA. There are no departures that affect Section 19L.8.

The hydrogen recombiners are removed from the ABWR design as described in Departure STD DEP T1 2.14-1, which incorporates amendments made to 10 CFR 50.44, "Combustible gas control for nuclear power reactors," The amended 10 CFR 50.44 eliminates the requirements for hydrogen control systems to mitigate a design basis LOCA hydrogen release.

No COLA revision is required as a result of this RAI response.

STP Attachment 6

EIS IDENT: ABWR TSD

GE Nuclear Energy

25A5680	SH NO. 1
REV. 1	

REVISION STATUS SHEET

DOC TITLE TECHNICAL SUPPORT DOCUMENT FOR THE ABWR

LEGEND OR DESCRIPTION OF GROUPS

TYPE: LICENSING INFORMATION

FMF:

MPL NO: A90-3230

REVISION			C
0	RM-01701 11/18/94		
1	R.R. BELANGER JAN 18 1995	RJA	
	CN01994 GENERAL DOCUMENT CHANGE CHK BY: R.R. BELANGER		

426E				

PRINTS TO

MADE BY	APPROVALS	GENERAL ELECTRIC COMPANY 175 CURTNER AVENUE SAN JOSE, CALIFORNIA 95125
N. PATEL 11/18/94	P.D. KNECHT 11/18/94	
CHK BY	ISSUED	
A. FORTIN 11/18/94	R.J. AHMANN 11/18/94	CONT ON SHEET 2

MS-WORD

Table 4
Cost Estimates of SAMDAs Evaluated for the ABWR Under NEPA

Potential Improvement	Cost Basis	Estimated Minimum Cost
1a. Severe Accident EPGs/AMGs	Plant specific procedure preparation beyond generic work by Owners' Group.	$ 600,000
1b. Computer Aided Instrumentation	Software modifications and interface hardware. Credit for averted onsite cost included.	$ 599,600
1c. Improved Maintenance Procedures/Manuals	Procedure preparation. Credit for averted onsite cost included.	$ 299,000
2a. Passive High Pressure System	System hardware and installation ($1,200,000), Building modification ($550,000). Credit for averted onsite cost included.	$ 1,744,000
2b. Improved Depressurization	Logic, pneumatic supplies, piping and qualification. Credit for averted onsite cost included.	$ 598,600
2c. Suppression Pool Jockey Pump	System hardware and electrical connections. Credit for averted onsite cost included.	$ 120,000
2d. Safety Related Condensate Storage Tank	Structural analysis and material. Credit for averted onsite cost included.	$ 1,000,000
3a. Larger Volume Containment (Double Free Volume)	Double current volume at $1200/ft^3. Analysis not included.	$ 8,000,000
3b. Increased Containment Pressure Capability (Sufficient pressure to withstand severe accidents)	Similar to Larger Volume Containment, but denser rebar and labor required. Assumed 50% higher cost	$ 12,000,000
3c. Improved Vacuum Breakers (Redundant valves in each line)	Eight lines at $10,000 per line	$ 100,000

Table 4 (Continued)

Potential Improvement	Cost Basis	Estimated Minimum Cost
3d. Improved Bottom Head Penetration Design	205 drives at $1,000/drive and $500,000 of analysis	$ 750,000
4a. Larger Volume Suppression Pool (Double effective liquid volume)	Assumed to be the same as Larger Volume Containment	$ 8,000,000
5a. Low Flow Filtered Vent	Hardware and Testing program	$ 3,000,000
7a. Drywell Head Flooding (Firewater crosstie to drywell head area)	Minor valve and piping modification with instrumentation	$ 100,000
8a. Additional Service Water Pump	System hardware, power supplies and support systems. Credit for averted onsite cost included.	$ 5,999,000
9a. Steam Driven Turbine Generator	System hardware, cabling and structural changes. Credit for averted onsite cost included.	$ 5,994,300
9b. Alternate Pump Power Source	400 kW generator at $300/kW. Credit for averted onsite cost included.	$ 1,194,000
10a. Dedicated DC Power Supply	5000 ft^2 building structure addition at $500/$ft^2$ and cabling	$ 3,000,000
11a. ATWS Sized Vent	Instrumentation and cabling in addition to training	$ 300,000
13a. Reactor Building Sprays (Firewater crosstie for reactor building sprays)	Minor valve and piping modification with instrumentation.	$ 100,000
14a. Flooded Rubble Bed	1250 ft^2 of material at $1000/lb	$ 18,750,000

STP Attachment 7

4. Calculate avoided property damage value per facility.

5. Sum avoided property damage over affected facilities.

In the 1983 Handbook, Heaberlin et al. made extensive use of NUREG/CR-2723 (Strip 1982) for offsite property cost estimation. Strip reported the present value of offsite health and property costs, onsite costs, and replacement power costs for accidents in release categories SST1 through SST3 for 91 U.S. power reactor sites. The offsite property costs were based on CRAC2 results, with 1970 population estimates and state-wide land use. The analyst may find the site-specific emphasis in Strip (1982) helpful in a more detailed value-impact analysis.

For a major effort beyond the standard analysis, it is recommended that the estimates be derived from information more site-specific than that used by Strip (1982). For power reactors, the MACCS code with the most recent data available should be used. This degree of effort would be relatively costly to conduct, both in terms of computer costs and data collection and interpretation costs. However, it would provide the highest degree of reliability.

Burke et al. (1984) examined the offsite economic consequences of severe LWR accidents, developing costs models for the following:

- population evacuation and temporary sheltering, including food, lodging, and transportation
- emergency phase relocation, including food, housing, transportation, and income losses
- intermediate phase relocation, beginning immediately after the emergency phase
- long-term protective actions, including decontamination of land and property and land area interdiction
- health effects, including the two basic approaches (human capital and willingness-to-pay).

Tawil et al. (1991) compared three computer models for estimating offsite property damage from power reactor accidents. Two of the models are the CRAC2 and MACCS codes; the third is the computer code DECON (Tawil et al. 1985). Three accident severity categories—SST1-SST3—are considered for the six Pasquill atmospheric stability categories (A-F). Offsite property damage is calculated for each pairing at cleanup levels from 10 through 200 rems. A study is also performed comparing the effect of modeling offsite damage to radii of 50 and 500 miles. It indicates that the choice of radius is significant only for the SST1 accident category, the differences being quite pronounced.

The FORECAST computer code for regulatory effects cost analysis (Lopez and Sciacca 1996) allows input for the offsite property attribute.

5.7.6 Onsite Property

Section 4.3.1 of the NRC Guidelines states that onsite property damage cost savings (i.e., averted onsite costs) need to be included in the value-impact analysis. In the net-value formulation it is a positive attribute.

Estimating the effect of the proposed action on onsite property involves three steps:

1. Estimate reduction in accident frequency (see Section 5.6).

2. Estimate onsite property damage.

3. Calculate reduction in risk to onsite property as

$$V_{OP} = N \Delta F U$$

where V_{OP} = monetary value of avoided onsite property damage ($)
N = number of affected facilities
ΔF = reduction in accident frequency (events/facility-year)
U = present value of property damage occurring with frequency F ($-year).

Reduction in onsite property damage costs (i.e., costs savings) is algebraically positive; increase (i.e., cost accruals) is negative (viewed as negative cost savings).

For the standard analysis, it is convenient to treat onsite property costs under three categories: 1) cleanup and decontamination, 2) long-term replacement power, and 3) repair and refurbishment. Each of these categories is considered below for power reactors with the focus on large-scale core-melt accidents. Additional categories of costs have been considered by Mubayi et al. (1995) and Burke et al. (1984) as outlined in Section 5.7.6.4, but they were either found to be speculative or contributed small fractions to the costs identified below.

5.7.6.1 Cleanup and Decontamination

Cleanup and decontamination of a nuclear facility, especially a power reactor, following a medium or severe accident can be extremely expensive. For example, Mubayi et al. (1995) report that the total cleanup and decontamination of TMI-2 cost roughly $750 million (in 1981 dollars). Murphy and Holter (1982) estimated cleanup costs for a reference PWR and BWR for the following three accident scenarios:

- Scenario 1 - a small LOCA in which ECCS functions as intended. Some fuel cladding ruptures, but no fuel melts. The containment building is moderately contaminated, but there is minimal physical damage.

- Scenario 2 - a small LOCA in which ECCS is delayed. Half of the fuel cladding ruptures, and some fuel melts. The containment building is extensively contaminated, but there is minimal physical damage.

- Scenario 3 - a major LOCA in which ECCS is delayed. All fuel cladding ruptures, and there is significant fuel melting and core damaged. The containment building is extensively contaminated and physically damaged. The auxiliary building undergoes some contamination.

In 1981 dollars, Murphy and Holter estimated the following cleanup costs:

Scenario	PWR	BWR
1	$1.05E+8	$1.28E+8
2	$2.24E+8	$2.28E+8
3	$4.04E+8	$4.21E+8

Mubayi et al. (1995) consider the TMI-2 accident to lie between Scenarios 2 and 3, lying closer to Scenario 3 in terms of the contamination and damage to the core. Murphy and Holter's costs were somewhat less than those actually realized at TMI. Mubayi et al. (1995) attribute the difference to three factors:

1. The start of the TMI cleanup was delayed by 2.5 years due to regulatory and financial requirements. Murphy and Holter assumed no additional delays between the accident and start of the cleanup. Mubayi et al. (1995) consider this somewhat unrealistic.

2. Decontamination at TMI required facilities not included in Murphy and Holter's reference plants (e.g., a hot chemistry laboratory, containment recovery service building, and comment center/temporary personnel access facility).

3. TMI required additional decontamination of the containment building after the reactor was defueled. Murphy and Holter excluded this in their analysis.

When these three factors are considered, the results from Murphy and Holter become reasonably consistent with the actual TMI cleanup costs ($7.50E+8 in 1981 dollars).

Burke et al. (1984) produced a very rough estimate of $1.7 billion (in 1982 dollars) for the cleanup and decontamination costs following a severe power reactor accident. An uncertainty range of approximately 50% was assigned, bringing the lower bound reasonably in line with the actual TMI cleanup cost. A study by Konzek and Smith (1990) updated the cleanup costs associated with Murphy and Holter's Scenario 3. Costs ranging from $1.22E+9 to $1.44E+9 (in undiscounted 1989 dollars) were estimated, based on real escalation rates of 4% to 8% during the cleanup period. A base cost of $1.03E+9 was estimated assuming no real escalation during the cleanup period.

After converting the costs to undiscounted 1993 dollars, the cost reported by Mubayi et al. (1995) for TMI is $1.2E+9, the base estimate from Konzek and Smith (1990) is $1.2E+9, and the estimate from Burke et al. (1984), which doubled the cost of TMI, is $2.5E+9. Based on these references, the total onsite cost estimates given in Section 5.7.6.4 are based on $1.5E+9 (undiscounted) for cleanup and decontamination (C_{CD} in the equations that follow). For sensitivity analysis, lower and upper bounds of $1.0E+9 and $2.0E+9 are recommended for evaluating severe accident effects.

Assuming the $1.5E+9 estimate is spread evenly over a 10-year period for cleanup (i.e., constant annual cost of C_{CD}/m = $1.5E+8 in the equation below, with C_{CD} = $1.5E+9 and m = 10 years), and applying a 7% real discount rate, the cost translates into a net present value of $1.1E+9 for a single event. This quantity is derived from the following equation (see Section B.2.3):

$$PV_{CD} = \left[C_{CD} / mr\right]\left[1 - \exp(-rm)\right]$$

where PV_{CD} = net present value of cleanup and decontamination costs for single event ($)
C_{CD} = total undiscounted cost for single accident in constant year dollars ($)
m = years required to return site to pre-accident state
r = real discount rate (as fraction, not percent).

Before proceeding, this present value must be decreased by the cleanup and decontamination costs associated with normal reactor end-of-life. The Yankee Atomic Electric Co. (NRC 1995c), Sacramento Municipal Utility District (NRC 1994), and Portland General Electric Co. (1995) provided the following estimates to the NRC for decommissioning their Yankee Rowe, Rancho Seco, and Trojan nuclear power plants, respectively: $3.41E+8 (1991 dollars), $2.80E+8 (1991 dollars), and $4.15E+8 (1993 dollars). These suggest a value of approximately $0.4E+9 (1993 dollars) for "normal" cleanup and decommissioning. The analyst can also consult Bierschbach (1995) for estimating PWR decommissioning costs and Bierschbach (1996) for estimating BWR decommissioning costs.

When spread evenly over the same 10-year period at a 7% real discount rate, this translates into a net present value of $0.3E+9. However, since this value would "normally" be applied at reactor end-of-life (i.e., 24 years later, using the

estimate from Table B.1), the net present value (at the same 7% real discount rate) is reduced to \$0.06E+9. Since this amounts to only 5% of the net present value for cleanup and decontamination following a severe accident (\$1.1E+9), it can be generally ignored.

The total onsite cost estimates shown in Section 5.7.6.4 integrate this net present value over the average number of remaining service years (24 years) using the following equation:

$$U_{CD} = \left[PV_{CD} / r\right]\left[1 - \exp(-rt_r)\right]$$

where U_{CD} = net present value of cleanup and decontamination over life of facility (\$-year)
t_r = years remaining until end of facility life.

The integrated cost is \$1.3E+10 over the life of a power reactor. This cost must be multiplied by the accident frequency (F, expressed in events per facility-year), and the number of reactors, to determine the expected value of cleanup and decontamination costs. To determine averted costs, the reduction in accident frequency ΔF is applied as outlined in Section 5.7.6.

For comparison, these costs can also be estimated for less severe accidents as defined by Murphy and Holter's Scenarios 1 and 2. The estimates shown in the following table were obtained by using \$1.1E+9 (1993 dollars) as a base value for Scenario-3 PV_{CD} costs, and applying the same relative fractions as shown in Murphy and Holter's (1982) results for Scenario-1 and 2 costs. The results from Murphy and Holter were not used directly because of the factors cited by Mubayi et al. (1995) in comparisons of those estimates with actual cleanup and decontamination costs at TMI.

Scenario	PV_{CD}	U_{CD}
1	\$3.1E+8	\$3.7E+9
2	\$6.0E+8	\$7.1E+9
3	\$1.1E+9	\$1.3E+10

The issue of license renewal has only moderate implications for the integrated cost estimates (U_{CD}). With longer operating lifetimes, the reactors are at risk for more years, and the costs would be expected to increase accordingly. However, because the additional costs are discounted to present worth terms, the effect is not substantial. For example, an additional life extension of 20 years would only increase the value of U_{CD} for a Scenario-3 accident 15% from \$1.3E+10 to \$1.5E+10.

5.7.6.2 Long-Term Replacement Power

Replaced power for short-term reactor outages is discussed in Section 5.7.7.1. Following a severe power reactor accident (replacement power need be considered only for electrical generating facilities), replacement power costs must be considered for the remaining reactor lifetime.[12]

Argonne National Laboratory (ANL) has developed estimates for long-term replacement power costs based on simulations of production costs and capacity expansion for representative pools of utility systems (VanKuiken et al. 1992). VanKuiken et al. examined replacement energy and capacity costs, including purchased energy and capacity charges required to provide the same level of system reliability as available prior to the loss of a power reactor (VanKuiken et al. 1993). In the event of a permanent shutdown, it was assumed that a reactor would be replaced by one or more alternative generating units, after an appropriate delay for planning and construction.

Capacity expansion and production cost simulations were performed for six representative power reactors over 40-year study periods. The results were used to estimate replacement power costs for each of 112 reactors which, at the time of the study, were expected to be in operation by 1996. Cost estimates for each reactor reflect the remaining lifetimes, reactor sizes, and ranges in short-term replacement energy costs (as encountered in each utility). Averages were determined by summing the individual reactor costs and dividing by the number of reactors evaluated. Characteristics for the "generic" reactor cited in Section 5.7.6.4 reflect an average unit size of 910-MWe and average life remaining of 24 years for reactors currently operating and planned.

Simulation results were first used to estimate the present value costs of single accidents occurring in each year of remaining facility lifetimes (quantity PV_{RP} used in the discussions that follow). Each of these net present values represents a summation of annual replacement power costs incurred from the year of the assumed accident to the final year of service. For example, the average net present value for an event occurring in 1993 is \$1.1E+9. For 1994, the cost is \$1.0E+9, and for 1995, the cost is \$0.9E+9. The decline in costs with each successive year reflects present value considerations and the fact that there are fewer remaining service years requiring replacement power.

The following equation can be used to approximate the average value of PV_{RP} for alternative discount rates.

$$PV_{RP} = [\$1.2E + 8 / r] \left[1 - \exp(-rt_f)\right]^2$$

where PV_{RP} = net present value of replacement power for a single event (\$).

The \$1.2E+8 value used in the above equation has no intrinsic meaning. It is treated in the equation similar to an equivalent annual cost, but it is actually a substitute for a string of non-constant replacement power costs that occur over the lifetime of the generic reactor after an event that takes place in 1993. The equation is only presented here for examining the effects of alternate discount rates and remaining reactor lifetimes.

The above equation for PV_{RP} was developed for discount factors in the range of 5%-10%. Unlike the equations for PV_{CD} and U_{CD}, the equation for PV_{RP} diverges from modeled results at lower discount rates. At a discount rate of 3% the recommended value for PV_{RP} is \$1.4E+9, as compared with the equation estimate of \$1.1E+9. For discount rates between 1% and 5% the analyst is urged to make linear interpolations using \$1.6E+9 at 1% and \$1.2E+9 at 5%. At higher discount rates the equation for PV_{RP} provides recommended estimates of \$1.2E+9 at 5% and \$1.0E+9 at 10%.

The results that are applied in Section 5.7.6.4 sum the single-event costs over all years of reactor service. While these summations were calculated directly from simulation results, ANL found that the outcomes could be closely approximated with the equation that follows. The squared term in this equation serves as a proxy for the fact that costs for events in future years decline due to the reduced number of remaining service years for which replacement power is required:

$$U_{RP} = [PV_{RP} / r] \left[1 - \exp(-rt_f)\right]^2$$

where U_{RP} = net present value of replacement power over life of facility (\$-year).

Replacement power costs for the generic unit are estimated to be approximately \$10 billion over the life of the facility. An uncertainty range for this average is estimated at approximately 20%. However, the range of estimates for specific power reactors varies directly with unit size, remaining life, and replacement energy costs. For example, costs were estimated to be \$7.5 billion for the 1040-MWe Zion-2 reactor, assuming 16 years of remaining operating life. Zion-2 is in a power pool with approximately average replacement energy costs. In contrast, costs for Big Rock Point were \$120 million due to its smaller size (67-MWe), shorter remaining life (8 years assumed), and average replacement energy costs. At the upper

limit were costs of $24 billion for the 1090-MWe Nine Mile Point 2 unit, assuming 34 years of service remaining. Nine Mile Point 2 is in a power pool with above average replacement energy costs.

As noted for PV_{RP}, the equation for U_{RP} was developed for discount rates ranging from 5%-10%. For lower discount rates, linear interpolations for U_{RP} are recommended between $1.9E+10 at 1% and $1.2E+10 at 5%. The equation for U_{RP} yields the recommended values of $1.2E+10 at 5% and $0.8E+10 at 10%, based on PV_{RP} values described previously.

As discussed in Section 5.7.6.4, these summed costs must be multiplied by the accident frequency (expressed in events per facility-year) to determine the expected value of replacement power costs for a typical reactor. To determine the value of reductions in the accident frequency due to regulatory actions, the total integrated costs must be multiplied by the reduction in accident frequency ΔF and the number of reactors affected (N).

The issue of license renewal has a much more significant impact on replacement power costs than on cleanup and decontamination costs. Extending the operating life by an additional 20 years would increase the net present value of a single event (PV_{RP}) by about 38%, and would increase the present value of costs integrated over the reactor life (U_{RP}) by about 90% (VanKuiken et al. 1992). Thus, a license renewal period of 20 years would mean the generic reactor would have a remaining life of 44 years, PV_{RP} would be estimated to be $1.5E+9, and U_{RP} would be approximately $1.9E+10 (1993 dollars).

For less severe accidents such as characterized by Scenario-1 events, the analyst is referred to Section 5.7.7.1 which addresses short-term replacement energy costs. Replacement capacity costs, which contribute to severe accident costs, are not incurred for more temporary reactor shutdowns.

5.7.6.3 Repair and Refurbishment

In the event of recoverable accidents (i.e., for Scenario 1, but not Scenarios 2 or 3), the licensee will incur costs to repair/replace damaged components before a facility can be returned to operation (these costs are not included in the total onsite cost estimates for severe accidents as addressed in Section 5.7.6.4). Burke et al. (1984) have estimated typical costs for equipment repair on the order of $1,000/hr of outage duration, based on data from outages of varying durations at reactors. They suggest an upper bound of roughly 20% of the long-term replacement power costs for a single event. Mubayi et al. (1995) observe that the $1,000/hr figure corresponds closely to the repair costs following the Browns Ferry fire and also to the TMI-1 steam generator retubing outage costs.

5.7.6.4 Total Onsite Property Damage Costs

Based on the information included in Sections 5.7.6.1 and 5.7.6.2, ANL has estimated the total cost due to onsite property damage following a severe reactor accident for the Zion-2 reactor and a "generic" 910-MWe reactor assumed to have a remaining life of 24 years. Total costs are assumed to consist of cleanup and decontamination costs and replacement power costs (repair and refurbishment costs are not included for severe accidents). The total costs described below correspond to the "risk-based" costs as defined by Mubayi et al. (1995):

> "...risk-based cost, the discounted net present value of the risk over the remaining life of the plant, which is proportional to the accident frequency [F]..."

The risk-based costs (quantities U, U_{CD}, and U_{RP} in the equations that follow) must be interpreted carefully to avoid misunderstandings. They do not represent the expected onsite property damage due to a single accident. Rather, they are the present value of a stream of potential losses extending over the remaining lifetime of the facility. Thus, they reflect the expected loss due to a single accident (given by quantities PV_{CD} and PV_{RP}); the possibility that such an accident could

occur, with some small probability, at any time over the remaining facility life; and the effects of discounting those potential future losses to the present value. When the quantity U is multiplied by the annual accident frequency, the result is the expected loss over the facility life, discounted to the present value.

The estimates for total risk-based costs attributed to regulatory actions that occur in 1993, expressed in 1993 dollars assuming a 7% real annual discount rate, are as follows:

Variable	Cost Component	Zion-2	"Generic" Reactor
U_{RP}	Replacement Power	\$0.7E+10 x F	\$1.0E+10 x F
U_{CD}	Cleanup & Decontamination	\$1.0E+10 x F	\$1.3E+10 x F
U	Total	\$1.7E+10 x F	\$2.3E+10 x F

Alternate values of U may be approximated for different discount rates, years of operation remaining, and estimates for C_{CD} and PV_{RP}. However, for changes in discount rate or final year of operation, the analyst is cautioned to revise the estimates for PV_{RP} using the equation described in Section 5.7.6.2 prior to re-estimating U from the equation that follows. Also, for discount rates lower than 5%, PV_{RP} and U_{RP} should be estimated from interpolation guidelines presented in Section 5.7.6.2 rather than from the equations. The relationship that defines total lifetime costs is

$$\begin{aligned} U &= U_{CD} + U_{RP} \\ &= \left[C_{CD} / mr^2\right]\left[1 - \exp(-rt_f)\right]\left[1 - \exp(-rm)\right] + \left[PV_{RP} / r\right]\left[1 - \exp(-rt_f)\right]^2 \end{aligned}$$

where U = total net present value of onsite property damage (\$-year).

The procedure outlined in Section 5.7.6 may be used to evaluate averted onsite property damage using these estimates. For illustration, assume that the reduction in severe accident frequency (ΔF) is 1.0E-6 and the number of reactors affected (N) is 111. The total averted onsite damage costs would be

$$V_{OP} = N\Delta FU = (111)(1.0E-6)(\$2.3E+10) = \$2.6E+6$$

The value of this reduction in accident frequency is \$2.6 million (net present value in 1993 dollars).

The \$2.3E+10 value used above is an appropriate generic estimate for regulatory requirements that become effective in 1993 and that affect severe accident probabilities in that year. For regulatory actions that affect accident frequencies in future years, the cost estimates must be adjusted to recognize that the number of reactor-years at risk and the number of service years requiring replacement power are reduced. Table 5.7 shows how these factors affect cost estimates for the 10-year period of 1993-2002. The results are expressed as net present values discounted to the year that the rulemaking is assumed to take effect.

To illustrate the use of these estimates, assume a reduction in accident frequency of 1.0E-6 begins in 1998 and affects all 111 of the remaining reactors. The revised estimate for U would be \$1.9E+10 and the total averted onsite damage costs for this reduction in frequency would be

$$V_{OP} = (111)(1.0E-6)(\$1.9E+10) = \$2.1E+6 \text{ (1993 dollars)}$$

Table 5.7 Onsite property damage cost estimates (U) for future years (1993 dollars discounted to year of implementation)

	Cleanup and Decontamination (U_{CD})	Replacement Power (U_{RP})	Total (U)
1993	$1.3E+10	$1.0E+10	$2.3E+10
1994	$1.2E+10	$9.6E+9	$2.2E+10
1995	$1.2E+10	$9.1E+9	$2.1E+10
1996	$1.2E+10	$8.6E+9	$2.1E+10
1997	$1.1E+10	$8.1E+9	$1.9E+10
1998	$1.1E+10	$7.6E+9	$1.9E+10
1999	$1.1E+10	$7.1E+9	$1.8E+10
2000	$1.1E+10	$6.6E+9	$1.8E+10
2001	$1.0E+10	$6.2E+9	$1.6E+10
2002	$1.0E+10	$5.7E+9	$1.6E+10

This would indicate that the reduction in accident frequency valued at $2.6 million beginning in 1993 would be valued at $2.1 million if introduced in 1998 (1993 dollars adjusted to 1998).

The following linear equation provides approximate cost estimates for implementation later than 10 years in the future. The result represents net present value (1993 dollars) discounted to the year of implementation. The analyst must adjust the 1993 dollars for general inflation if costs are to be expressed in alternate reference-year dollars. (See Section 5.8 for information on adjusting dollar years.)

$$U = \$2.3E+10 - (\$6.7E+8)\,(t_i - 1993)$$

where t_i = year of reduction in accident frequency.

Thus, for regulatory actions that would affect accident probabilities for 86 reactors remaining in service in 2010, the revised estimate for U would be

$$\begin{aligned} U &= \$2.3E+10 - (\$6.7E+8)\,(2010 - 1993) \\ &= \$1.2E+10 \text{ (1993 dollars adjusted to 2010)} \end{aligned}$$

The total averted onsite damages costs for a reduction in accident frequency of 1.0E-6 would be

$$\begin{aligned} V_{OP} &= (86)\,(1.0E-6)\,(\$1.2E+10) \\ &= \$1.0E+6 \text{ (1993 dollars adjusted to 2010)} \end{aligned}$$

This example also illustrates that the number of reactors at risk and the average remaining years of reactor service change in the evaluation of future regulatory initiatives. Because of the distribution of license expiration dates, the average remaining reactor life does not decrease on a one-to-one basis with each successive year in the future.

For 20-year license renewal considerations, the estimates for U discussed above should be increased by approximately 50%. In 1993, U_{CD} would be estimated at \$1.5E+10 (versus \$1.3E+10 for 40-year license), and U_{RP} would be estimated to be \$1.9E+10 (versus \$1.0E+10 for 40-year license). This yields a total of \$3.4E+10 (1993 dollars) as compared with \$2.3E+10 for the 40-year license assumption.

Costs for onsite property damage from non-reactor accidents have been assembled in Section C.2.5. However, most are given as combined offsite and onsite damage costs.

For a major effort beyond the standard analysis, there are two general ways to achieve a greater level of detail: 1) the analysis can be conducted for individual facilities or groups of similar facilities, using site-specific information; 2) the analysis can provide cost information in much greater detail. With regard to the first approach, the most relevant site-specific information includes the cost of long-term replacement power and the value of the facility and equipment at risk, taking into account the remaining useful life of the facility. The analyst is referred to VanKuiken et al. (1992) for further detail on average shutdown costs for different categories of reactors (e.g., by region, reactor supplier, architect engineer, etc.), and guidance for scaling costs for different unit sizes and remaining lifetimes.

With regard to providing greater detail on the cost information, the major cost elements (in addition to replacement power) are likely to include decontamination and other cleanup costs and repair or replacement of plant and equipment that is physically damaged. Other costs relate to transporting and disposing of contaminated materials and equipment, and startup costs. Costs for monitoring the site for radiation and fixing contamination at the site will likely be insignificant relative to the other costs. The analyst is referred to Murphy and Holter (1982), and the follow-up study by Konzek and Smith (1990), for detailed cost estimates to decontaminate a nuclear power reactor following a postulated accident.

Burke et al. (1984) examined the onsite economic consequences of severe LWR accidents, developing cost models for the following:

- replacement power, drawing information mainly from Buehring and Peerenboom (1982) (which has been updated by VanKuiken et al. [1992])
- plant decontamination, including both medium and large consequence events
- plant repair, spanning small to large consequence events
- early decommissioning for medium and large consequence events
- worker health effects and medical care, primarily for medium and large consequence events
- electric utility "business" (i.e., costs resulting from changed risk perceptions in financial markets and the need to replace the income once produced by the operating plant after a power plant is permanently shutdown)
- nuclear power "industry" (i.e., costs resulting from elimination or slowed growth in the U.S. nuclear power industry due to altered policy decisions and risk perceptions following a severe accident)
- onsite litigation (i.e., "legal fees for the time and effort of those individuals involved in the litigation process").

The first three categories of costs have been covered in Sections 5.7.6.1-5.7.6.3. The other categories are covered elsewhere in this Handbook or are considered to be either speculative or small in magnitude relative to replacement power, cleanup and decontamination, and repair costs.

The FORECAST computer code for regulatory effects cost analysis (Lopez and Sciacca 1996) allows input for the onsite property attribute.

5.7.7 Industry Implementation

This section provides procedures for computing estimates of the industry's incremental costs to implement the proposed action. Estimating incremental costs during the operational phase that follows the implementation phase is discussed in Section 5.7.8. Incremental implementation costs measure the additional costs to industry imposed by the regulation; they are costs that would not have been incurred in the absence of that regulation. Reduction in the net cost (i.e., cost savings) is algebraically positive; increase (i.e., cost accrual) is negative (viewed as negative cost savings). Both NRC and Agreement State licensees should be addressed, as appropriate.

In general, there are three steps that the analyst should follow in order to estimate industry implementation costs:

Step 1 - Estimate the amount and types of plant equipment, materials, and/or labor that will be affected by the proposed action.

Step 2 - Estimate the costs associated with implementation.

Step 3 - If appropriate, discount the implementation costs, then sum (see Section B.2).

In preparing an estimate of industry implementation costs, the analyst should also carefully consider all cost categories that may be affected as a result of implementing the action. Example categories include

- land and land-use rights
- structures
- hydraulic, pneumatic, and electrical equipment
- radioactive waste disposal
- health physics
- monitoring equipment
- personnel construction facilities, equipment, and services
- engineering services
- recordkeeping
- procedural changes

- license modifications
- staff training/retraining
- administration
- facility shutdown and restart
- replacement power (power reactors only)
- reactor fuel and fuel services (power reactors only)
- items for averting illness or injury (e.g., bottled water or job safety equipment).

Note that transfer payments (see Section 4.3) should not be included.

For the standard analysis, the analyst should use consolidated information to estimate the cost to industry for implementing the action. Sciacca (1992) is a prime source of such information, providing not only cost estimates, but also labor hours, cost rates, and adjustment factors, mainly for reactor facilities. Appropriate references are cited by Sciacca. The FORECAST computer code for regulatory effects cost analysis (Lopez and Sciacca 1996) incorporates much of the information assembled by Sciacca (1992) into a computer database for the analyst's use in estimating industry implementation as well as other costs.

Step 1 - Estimate the amounts and types of plant equipment, materials, and/or labor that will be affected by the proposed action, including not only physical equipment and craft labor, but professional staff labor for design, engineering, quality assurance, and licensing associated with the action. If the action requires work in a radiation zone, the analyst should account for the extra labor required by radiation exposure limits and low worker efficiency due to awkward radiation protection gear and tight quarters (see discussion of labor productivity in Section 5.7.4.1).

When performing a sensitivity analysis, but not for the best estimate, the analyst should include contingencies, such as the most recent greenfield construction project contingency allowances supplied by Robert Snow Means Co., Inc. (1995). They suggest adding contingency allowances of 15% at the conceptual stage, 10% at the schematic stage, and 2% at the preliminary working drawing stage. The FORECAST computer code (Lopez and Sciacca 1996) contains an option to include an allowance for uncertainty and cost variations at the summary cost level. The Electric Power Research Institute (EPRI 1986) offers guidelines for use in estimating the costs for "new and existing power generating technologies." EPRI suggests applying two separate contingency factors, one for "projects" to cover costs resulting from more detailed design, and one for "process" to cover costs associated with uncertainties of implementing a commercial-scale new technology.

Step 2 - Estimate the costs associated with implementation, both direct and indirect. Direct costs include materials, equipment, and labor used for the construction and initial operation of the facility during the implementation phase. Indirect costs include required services. The analyst should identify any significant secondary costs that may arise. One-time component replacement costs and associated labor costs should be accounted for here. For additional information on cost categories, especially for reactor facilities, see Schulte et al. (1978) and United Engineers and Constructors, Inc. (1979; 1988a, b).

Step 3 - If appropriate, discount the costs, then sum. If costs occur at some future time, they should be discounted to yield present values (see Section B.2). If all costs occur in the first year or if present value costs can be directly estimated, discounting is not required. Generally, implementation costs would occur shortly after adoption of the proposed action.

When performing value-impact analyses for non-reactor facilities, the analyst will encounter difficulty in finding consolidated information on industry implementation costs comparable to that for power reactors. Comprehensive data sources such as Sciacca (1992) and the references from which he drew his information are generally unavailable for non-reactor facilities. Some specific information for selected non-reactor facilities is in Sections C.7-C.10. The types of non-reactor facilities (see Section C.1) are quite diverse. Furthermore, within each type, the facility layouts typically lack the limited standardization of the reactor facilities. These combine to leave the analyst pretty much "on his own" in developing industry implementation costs for non-reactor facilities. The analyst should follow the general guidelines given in this Handbook section. Specific data may be best obtained through direct contact with knowledgeable sources for the facility concerned, possibly even the facility personnel themselves.

For a major effort beyond the standard analysis, the analyst should obtain very detailed information, in terms of the cost categories and the costs themselves. The analyst should seek guidance from NRC contractors or industry sources experienced in this area (AE firms, etc.). The incremental costs of the action should be defined at a finer level of detail. The analyst, should refer to the code of accounts in the Energy Economic Data Base (EEDB [United Engineers and Constructors, Inc. 1988b]) or Schulte et al. (1978) to prepare a detailed account of implementation costs.

5.7.7.1 Short-Term Replacement Power

For power reactors, the possibility that implementation of the proposed action may result in the need for short-term replacement power must be addressed. Section 4.3.2 of the Guidelines indicates that replacement power costs are to be incorporated into a regulatory analysis when appropriate. Unlike the long-term costs associated with severe power reactor accidents discussed in Section 5.7.6.2, the replacement power costs associated with industry implementation of a regulatory action would be short-term.

For a "typical" 910-MWe reactor operating at an average capacity factor of 60%-65%, VanKuiken et al. (1992) suggests $310,000/day (1993 dollars) as an average cost for short-term replacement power. The 60%-65% range in capacity factor is representative of annual averages, accounting for unplanned outage periods and planned outage periods for maintenance and refueling. However, if the timing of a short-term shutdown coincides with a time when a power reactor is expected to be fully operational, then a higher average cost per day is more appropriate. At a capacity factor of 100%, the average cost for the typical reactor is estimated to be $480,000/day (1993 dollars).

At a more detailed level, VanKuiken et al. (1992) project the seasonal replacement power costs for potential short-term shutdowns of 112 nuclear power plants over the five-year period from 1992 through 1996. These costs are estimated from probabilistic production-cost simulations of pooled utility-system operations. Average daily replacement power costs are presented by season for each of the 112 plants. The 20 U.S. power pools containing these plants are identified along with their following characteristics: total system capacity, annual peak load, annual energy demand, annual load factor, prices for fuels, and mix of generation by fuel type.

The sensitivity of replacement power costs to changes in oil and gas prices is quantified for each power pool. The effects of multiple plant shutdowns are addressed, with the replacement power costs quantified for each pool assuming all plants within the pool are shutdown.

The replacement power cost information compiled in an analogous but earlier study by VanKuiken et al. (1987) has subsequently been incorporated into two cost analysis computer codes. The Replacement Energy Cost Analysis Package (RECAP [VanKuiken et al. 1994]) determines the replacement energy costs associated with short-term shutdowns of nuclear power plants, and can be applied to determine average costs for general categories based on location, unit type (e.g., BWR), constructor, utility, and other differentiating criteria. Plant-specific costs are also available, and can be evaluated for user-specified outage durations and alternative capacity factor assumptions. FORECAST (Lopez and Sciacca 1996), a computer code for regulatory effects cost analysis, provides the user with the capability to estimate replacement power costs in current year dollars. Sciacca (1992) also provides a discussion and data for use in estimating replacement power costs based on this earlier study by VanKuiken et al. (1987).

Imposition of a new regulation often requires that a nuclear power plant be shutdown while the modification takes place. If the requirement is needed to meet adequate protection, the analyst can assume that the required downtime is independent of any scheduled downtime, thereby realizing full replacement power costs. However, the modification often is not needed to meet adequate protection, enabling it to be completed during already scheduled downtime. Only if the time needed to perform the modification exceeds that allotted for the scheduled downtime should any replacement power costs accrue, these being solely due to the excess time.

The most likely scenario permits the modification to be accommodated completely within already scheduled downtime, and this has frequently been the policy adopted by the NRC. As a result, no replacement power costs accrue. While this assumption holds for a modification performed in the absence of others required by new regulations, it tends to underestimate the cost of multiple modifications resulting from the cumulative effect of new NRC requirements. When multiple modifications are performed, as they often are, the originally scheduled downtime may be insufficient to accommodate all of them. Usually, this results from the limited number of available maintenance personnel and space restrictions for nearby component repair or service.

Historic data indicate roughly 15 days per year, or 17% and 25% of the annually scheduled downtime for PWRs and BWRs, respectively, can be attributed to the cumulative impact of new regulatory requirements. Assuming the contribution of each regulatory requirement to the incremental downtime equals the overall percentage increase, one can assign a prorated share to that requirement (i.e., 17% for PWRs, 25% for BWRs, or roughly 20% for LWRs in general). For example, if a regulatory requirement requires one-week of reactor shutdown time, 1.2 days (PWRs), 1.8 days (BWRs), or 1.4 days (LWRs) of additional downtime and, thus, replacement power costs would accrue.

5.7.7.2 Premature Facility Closing

Several nuclear power plants have been voluntarily shut down prior to the expiration of their operating licenses. Normally, a decommissioning cost of approximately \$0.3E+9 (1993 dollars) would be associated with an end-of-life shutdown (see Section 5.7.6.1). However, if a proposed regulatory requirement is expected to result in a premature shutdown, this cost is shifted to an earlier time with an associated net increase in its present value. For example, if a plant with an estimated t years of remaining life is prematurely closed, the net increase in present value, for a real discount rate of r, becomes (\$0.3E+9) $[1 - 1/(1+r)^t]$.

Thus, a plant closed 20 years early will incur an additional cost of \$0.2E+8 for a 7% real discount rate.

5.7.8 Industry Operation

This section provides procedures for estimating industry's incremental costs during the operating phase (i.e., after implementation) of the proposed action. The incremental costs measure the additional costs to industry imposed by the proposed action; they are costs that would not have been incurred in the absence of the action. Reduction in the net cost