Attachment C

Clean Water Act Documentation

- SPDES Permit NY-0004472
- Water Quality Certification for IP1 and IP2, December 7, 1970.
- Water Quality Certification for IP3, May 2, 1975.

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DIVISION OF WATER
BUREAU OF WASTEWATER FACILITIES DESIGN

NEW YORK STATE DEPARTMENT OF ENVIRONMENTAL CONSERVATION

State Pollutant Discharge Elimination System (SPDES)
DISCHARGE PERMIT
Special Conditions (Part 1)

Industrial Code	4911	Facility ID Number: NY-	000 4472
Discharge Class (CL)	03	UPA Tracking Number:	3086-0062
Toxic Class (TX)	T	Effective Date (EDP):	October 1, 1987
Major D.B.	13	Expiration Date (ExDP):	October 1, 1992
Sub D.B.	01	Modification Date(s):	
Water Index Number	H	Attachment(s):	General Conditions (Part II, 2/85)

"A" - Order on Consent, July 17, 1986
"B" - Order on Consent, August 20, 1987

This SPDES permit is issued in compliance with Title 8 of Article 17 of the Environmental Conservation Law of New York State and in compliance with the Clean Water Act, as amended, (33 U.S.C. §1251 et seq.) [hereinafter referred to as "the Act"]

Attn: Robert Keegan/John W. Blake

Permittee Name: Consolidated Edison Co. of New York/New York Power Authority

Street: 4 Irving Place, Room 300/123 Main Street

City: New York/White Plains State: NY/NY Zip Code: 10003/10601

is authorized to discharge from the facility described below.

Facility Name: Indian Point Generating Station (Units 1&2 Con Ed) & (Unit 3 PASNY)

Location (C,T,V): Buchanan (V) County: Westchester

Mailing Address (Street): Broadway and Bleakley Avenue

Mailing Address (City): Buchanan State: NY Zip Code: 10511

from Outfall No. 001 at: Latitude 41°16'7" & Longitude 73°57'19"

into receiving waters known as: Hudson River Class SB

and: (list other Outfalls, Receiving Waters & Water Classification)

001	Hudson River	SB
002	Hudson River	SB
003	Hudson River	SB
004	Hudson River	SB
005	Hudson River	SB
006	Hudson River	SB
007	Hudson River	SB
008	Hudson River	SB
009	Hudson River	SB

in accordance with the effluent limitations, monitoring requirements and other conditions set forth in this permit.

This permit and the authorization to discharge shall expire on midnight of the expiration date shown above and the permittee shall not discharge after the expiration date unless this permit has been renewed, or extended pursuant to law. To be authorized to discharge beyond the expiration date, the permittee shall apply for permit renewal as prescribed by Sections 17-0803 and 17-0804 of the Environmental Conservation Law and Parts 621, 752, and 755 of the Departments' rules and regulations

PERMIT ADMINISTRATOR	DATE ISSUED	ADDRESS
Ralph Manna, Jr.	8/28/87	21 South Putt Corners Rd. New Paltz, NY 12561

Distribution:
C. Manfredi/P. Doshna
R. Hannaford - BWFD
Westchester Co. H.D.
EPA, NY - R. Baker
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E. Reilly (pg. 1)
E. Radle, BEP - Albany
B. Brandt

Ralph Manna Jr.

SIGNATURE

FINAL EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the Period Beginning October 1, 1987

and lasting until October 1, 1992

the discharges from the permitted facility shall be limited and monitored by the permittee as specified below:

Outfall Number & Effluent Parameter	Discharge Limitations Daily Avg	Discharge Limitations Daily Max.	Units	Minimum Monitoring Requirements Measurement Frequency	Minimum Monitoring Requirements Sample Type

001* Discharge Canal[a,b]

The permittee shall discharge condenser cooling water so that the following conditions are satisfied:

1. At no time shall the maximum discharge temperature at Station DSN 001 exceed 43.3°C (110°F).
2. Between April 15 and June 30, the daily average discharge temperature at Station DSN 001 shall not exceed 34°C (93.2°F) for an average of more than ten days per year during the term of this permit beginning with 1981; provided that in no event shall the daily average discharge temperature at Station DSN 001 exceed 34°C (93.2°F) on more than 15 days between April 15 and June 30 in any year.
3. Whenever, due to forced outage or other technical problem, e.g. equipment failure, it is necessary to remove one or more circulating water pumps from service at an operating unit (or units), pumps at any non-operating unit (or units), including Unit 1, may be used to augment flow in the discharge canal as necessary to meet temperature limits, and will not be considered a violation of settlement outage requirements at the non-operating unit provided that in no event shall total Station flow, as so augmented, exceed the equivalent of full circulator flow at each unit which is then operating.
4. If the discharge temperature limits in clauses 1 and 2 above are exceeded as a result of reduced flow required by Section 2.D of the Settlement Agreement, corrective action, which may include increasing cooling water flow as necessary up to the equivalent of full circulator flow for each unit then operating, shall be taken as quickly as practical and will not be considered a violation of outage requirements at the non-operating unit. During the period required for corrective action (which shall not exceed 24 hours), the discharge will not be considered to be in excess of the foregoing temperature limits. To the extent practical the permittee shall anticipate when the ambient river temperature will rise to such level that the prevailing reduced cooling water flow rate specified in the Settlement will fail to maintain discharge temperature below 34°C, and may, upon consultation with DEC, increase flow to the next rate scheduled in the Settlement prior to the discharge temperature exceeding 34°C.

* Nothing contained herein shall be construed to change or otherwise affect the provisions of the Settlement Agreement.

.. Except as set forth above, there shall be no thermal effluent limitations which govern or otherwise affect the operation of the Station or discharges therefrom.

INTERIM EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the Period Beginning October 1, 1987

and lasting until January 1, 1989

the discharges from the permitted facility shall be limited and monitored by the permittee as specified below:

Outfall Number & Effluent Parameter	Discharge Limitations Daily Avg.	Discharge Limitations Daily Max.	Units	Minimum Monitoring Requirements Measurement Frequency	Minimum Monitoring Requirements Sample Type
001* Discharge Canal[a,b]					
Total Residual Chlorine[c]	NA	0.2	mg/l	(See footnotes q,r)	
Lithium Hydroxide	NA	0.01[d]	mg/l	Monthly	Calculation
Boron	NA	1.0[e]	mg/l	Weekly	Calculation
Boron	NA	525[e]	lbs/day	Weekly	Calculation
pH (Range) 6.0 - 9.0			SU	Weekly	Grab

*Outfall 001 is the point prior to confluence of the discharge from the common discharge canal and the Hudson River.

Internal Waste Streams Effluent Limitations

Outfall Number & Effluent Parameter	Daily Avg.	Daily Max.	Units	Measurement Frequency	Sample Type
001A - Sewage Treatment Plant					
Flow	Monitor	Monitor	GPD	Continuous	Recorder
BOD_5	30[g]	45[h]	mg/l	Monthly	6hr Composite
Total Suspended Solids	30[g]	45[h]	mg/l	Monthly	6hr Composite
Settleable Solids		0.3	ml/l	Weekly	Grab
Fecal Coliform	200[i]	400[j]	NO./100 ml	Weekly	Grab
Total Residual Chlorine[p]	0.5(min.)	3.0	mg/l	Weekly	Grab
pH (Range)	Monitor	Monitor	SU	Weekly	Grab
Sum of 001B, 001C, 001D, 001E, 001G & 001K, 001L					
Flow	Monitoring Only		MGD	Weekly	Instantaneo
Total Suspended Solids	30	50	mg/l	Weekly	Grab[k]
Sum of 001C & 001D					
Flow	Monitoring Only		MGD	Weekly	Instantar
Hexavalent Chromium	0.05	0.1	mg/l	Monthly	Grab[l]
Total Chromium	0.5	1.0	mg/l	Weekly	Grab[l]
Lithium Hydroxide	Monitoring Only		mg/l	Monthly	Grab[l]

FINAL EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the Period Beginning January 1, 1989

and lasting until October 1, 1992

the discharges from the permitted facility shall be limited and monitored by the permittee as specified below:

Outfall Number & Effluent Parameter	Discharge Limitations Daily Avg.	Discharge Limitations Daily Max	Units	Minimum Monitoring Requirements Measurement Frequency	Minimum Monitoring Requirements Sample Type
001* Discharge Canal[a,b]					
Total Residual Chlorine[c]	NA	0.2	mg/l	(See footnotes q,r)	
Lithium Hydroxide	NA	0.01[d]	mg/l	Monthly	Calculation
Boron	NA	1.0[e]	mg/l	Weekly	Calculation
Boron	NA	525[e]	lbs/day	Weekly	Calculation
pH (Range) 6.0 - 9.0			SU	Weekly	Grab

*Outfall 001 is the point prior to confluence of the discharge from the common discharge canal and the Hudson River.

Internal Waste Streams Effluent Limitations

001A - Sewage Treatment Plant

No Discharge Allowed

Sum of 001B, 001C, 001D, 001E, 001G & 001K, 001L					
Flow	Monitoring Only		MGD	Weekly	Instantaneous
Total Suspended Solids	30	50	mg/l	Weekly	Grab[k]

Sum of 001C & 001D					
Flow	Monitoring Only		MGD	Weekly	Instantaneous
Hexavalent Chromium	0.05	0.1	mg/l	Monthly	Grab[l]
Total Chromium	0.5	1.0	mg/l	Weekly	Grab[l]
Lithium Hydroxide	Monitoring Only		mg/l	Monthly	Grab[l]

EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning October 1, 1987
and lasting until PERMIT EXPIRATION
the discharges from the permitted facility shall be limited and monitored by the permittee as specified below:

Outfall Number & Effluent Parameter	Discharge Limitations Daily Avg.	Daily Max.	Units	Minimum Monitoring Requirements Measurement Frequency	Sample Type
Sum of 01B, 01C, 01D & 01J, 01L					
Flow	Monitoring	Only	MGD	Weekly	Instantaneous
Boron	Monitoring	Only	mg/l	Weekly	Grab*
001C					
Flow	Monitoring	Only	MGD	Monthly	Instantaneous
001E					
Flow	Monitoring	Only	MGD	Weekly	Instantaneous
001G					
Flow	Monitoring	Only	MGD	Weekly	Instantaneous
Phosphates as P**	16	38	lbs/day	Monthly	Grab
001I					
Flow	Monitoring	Only	MGD	Footnote a	Footnote a
001J***					
Flow	Monitoring	Only	MGD	Weekly	Estimate
Oil & Grease		No visible oil or sheen	mg/l	Weekly	Visual Observation
Sum of 01C, 01D, 01K and 01L					
Oil & Grease		15	mg/l	Monthly	Grab*

***This applies to only those internal streams at Indian Point 2, which comprise this outfall.*

***Because this outfall cannot be monitored, the following shall apply:

1. All oil spills shall be handled under the SPCC plan.
2. Flow tributary to the floor drains shall not contain more than 15 mg/l of oil and grease nor any visible sheen
3. Treated wastewater from the desilting operation within the intake structure and forebays shall be monitored once per 12 hour shift on the sand filter effluent. Grab samples shall be analyzed for total suspended solids and oil & grease. An estimate of discharge flow rate and a visual observation for the presence of any visible sheen shall be made on the sand filter effluent. The limitations for this discharge event are: 15 mg/l (oil&grease), 50 mg/l (total suspended solids) and no visible sheen.

LUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning November 20, 2000 and lasting until permit expiration the discharges from the permitted facility shall be limited and monitored by the permittee as specified below:

Outfall Number & Effluent Parameter	Discharge Limitations Daily Avg.	Daily Max	Units	Minimum Monitoring Requirements Measurement Frequency	Sample Type
01K - Filter Backwash					
Flow	Monitor	Monitor	GPD	Weekly	Instantaneous
001C					
Flow	Monitoring	Only	MGD	Monthly	Instantaneous
001L - Condensate Polisher System Effluent and Stormwater Runoff from Chemical Bulk Storage Secondary Conainment					
Flow	Monitor	Monitor	GPD	Weekly	Instantaneous
pH	(Range 6.0-9.0)		SU	Monthly	Grab
Chlorine, Total Residual	NA	Monitor	mg/l	Monthly	Grab
N - Reverse Osmosis Reject					
Flow	Monitor	Monitor	GPD	Weekly	Instantaneous
Oil & Grease	NA	15	mg/l	Weekly	Grab
Total Suspended Solids	30	50	mg/l	Weekly	Grab
002-009 - Uncontaminated Stormwater Discharge					

No monitoring required

:ION LEVEL REQUIREMENTS

The parameters listed below have been reported present in the discharge but at levels that currently do not require water-quality or technology-based limits. Action levels have been established which if exceeded will result in reconsideration of Water Quality and Technology based limits.

Routine action level monitoring results, if not provided for on the Discharge Monitoring Report (DMR) form, shall be appended to the DMR for the period during which the sampling was conducted.

If any of the action levels is exceeded, the permittee shall undertake a short-term, high-intensity monitoring program for this parameter. Samples identical to those required for routine monitoring purposes shall be taken on each of at least three operating days and analyzed. Results shall be expressed in terms of both concentration and mass, and shall be submitted no later than the end of the third month following the month when the action level was first exceeded. Results may be appended to a DMR or transmitted under separate cover to the same addresses. If levels higher than the action levels are confirmed, the result shall constitute a revised application and the permit shall be reopened for consideration of revised action levels or effluent limits.

The permittee is not authorized to discharge any of the listed parameters at levels which may cause or contribute to a violation of water quality standards.

Outfall Number and Effluent Parameter	Action Level	Units	Minimum Monitoring Requirements: Measurement Frequency	Minimum Monitoring Requirements: Sample Type
001L - Condensate Polisher System Effluent				
·rides	5	lbs/day	Semi-Annual	Grab
.n	4	mg/l	Semi-Annual	Grab
·opper	1.0	mg/l	Semi-Annual	Grab
001A - Sewage Treatment Plant (No discharge allowed after January 1, 1989)				
Copper	0.5	mg/l	Semi-Annual	Grab
Mercury	0.1	mg/l	Semi-Annual	Grab
Zinc	1.0	mg/l	Semi-Annual	Grab

Modified: 9-30-99 (GDH)

Footnotes

a. Discharge 001 shall occur only through the subsurface ports of the outfall structure.

b. When the temperature in the discharge canal exceeds 90°F or the site gross electric output equals or exceeds 600MW the head differential across the outfall structure shall be maintained at a minimum of 1.75 feet. When required, adjustment of the ports shall be made within four hours of any change in the flow rate of the circulating water pumps. If compliance is not achieved, further adjustments of the ports shall be made to achieve compliance. The requirements of the Settlement Agreement flow schedules shall take priority over the requirements of this footnote.

c. The service water system may be chlorinated continuously. Should the condenser cooling water system be chlorinated, the maximum frequency of chlorination for the condensers of each unit shall be limited to two hours per day. The total time for chlorination of the three units for which this permit is issued shall not exceed nine hours per week. Chlorination shall take place during daylight hours and shall not occur at more than one unit at a time.

d. The calculated quantity of these substances in the discharge shall be determined by using the analytical results obtained from sampling that is to be performed on internal waste streams 01C and 01D.

The calculated quantity of this substance in this discharge shall be determined by using the analytical results obtained from sampling that is to be performed on internal waste streams 01B, 01C, 01D and 01L and releases from Unit 3's chemical batch tanks into 01J.

(Footnote f has been removed. Text has been placed in Additional Requirement #8.)

g. Arithmetic mean of the values for effluent samples collected over a 30 day period.

h. Arithmetic mean of the values for effluent samples collected over a 7 day period.

i. 30 day geometric mean.

j. 7 day geometric mean.

k. One flow proportioned composite sample shall be obtained from one grab sample taken from each of the internal waste streams 01B, 01C, 01D, 01E, 01G, and 01L.

l. One flow proportioned composite sample shall be obtained form one grab sample taken from each of the internal waste streams 001C and 001D. Sampling is not required if use of chromium is discontinued.

One grab sample shall be obtained from each of the internal waste streams 001C, 001D, 001K and 001L and the samples shall be analyzed separately. The results shall be reported by computing the flow-weighted average.

One flow proportioned composite sample shall be obtained from one grab sample taken from each of the internal waste streams 01B, 01C, 01D, 01L and each release from the chemical batch tanks at Unit 3 into 01J.

o. *The flow of condenser cooling water discharges shall be monitored and recorded every eight hours by recording the operating mode of the circulating water pumps.* Any changes in the flow rate of each circulating water pump shall be recorded, including the date and time, and reported monthly together with the Discharge Reporting Form. The permittee shall indicate whether any circulating pumps were not in operation due to pump breakdown or required pump maintenance and the period(s) (dates and times) the discharge temperature limitation was exceeded, if at all. Methods, equipment, installation, and procedures shall conform to those prescribed in the Water Measurement Manual, U.S. Department of the Interior, Bureau of Reclamation, Washington D.C.: 1967 or equivalent approved by the permit issuing authority.

p. Effluent disinfection is required all year. If chlorine is used for disinfection, a chlorine residual of 0.5 - 3.0 (Range) shall be maintained in the chlorine contact chamber effluent.

q. Continuous monitoring of TRC during condenser chlorination is required. A continuous TRC monitor shall be installed by October 1, 1987 or the date condenser chlorination begins, whichever is later. Prior to installation of the continuous monitor or when the continuous monitor fails, is inaccurate, or is unreliable, TRC shall be monitored during condenser chlorination by analyzing grab samples taken at least once every 30 minutes during each chlorination period.

r. Grab samples shall be taken at least once daily during low level service water chlorination and at least once every 30 minutes during high level service water chlorination. During service water chlorination, Outfall 001 TRC concentrations may be determined by either direct measurement at Outfall 001 or by multiplying a measured TRC concentration in the service water system by the ratio of chlorinated service water flow to the total site flow.

Additional Requirements:

1. There shall be no discharge of PCB's from this facility.

2. Collected screenings, sludges, and other solids and precipitates separated from the Permittee's discharges and/or intake water authorized by this permit shall be disposed of in such a manner as to prevent entry of such materials into navigable waters or the tributaries. Any fish, shellfish, or other organisms collected or trapped as a result of intake water screening or treatment may be returned to the water body habitat, together with associated solids.

3. The permittee shall submit on a quarterly basis to the NYSDEC at its offices in White Plains and Albany a monthly report of daily operating data, by the 28th of the month following the end of the quarter, that includes the following:

   a. Daily minimum, maximum and average station electrical output shall be determined and logged.

   b. Daily minimum, maximum and average water use shall be directly or indirectly measured or calculated and logged.

   c. Temperature of the intake and discharges shall be measured and recorded continuously. Daily minimum, maximum and average intake and discharge temperatures shall be logged.

4. Biological Monitoring and Reporting

   The permittee shall comply with biological monitoring requirements which shall be embodied in a Memorandum of Agreement (MOA) to be entered into between the NYSDEC and the Permittee for the permit issued to Indian Point Generating Station Unit 1-3. Monitoring requirements shall be consistent with the Hudson River Settlement Agreement and Attachment V thereto.

   Live sturgeon collected during biological monitoring studies will be counted, measured, and examined for tags, then carefully returned to the river as quickly as possible. Dead sturgeon collected during biological monitoring studies shall be counted, weighed, measured, examined for tags and frozen for salvage for the Department of Environmental Conservation for up to one year, at which time the sturgeon will be disposed of in a sanitary landfill. Each sturgeon shall be individually labeled indicating date of capture and appropriate measurements. The permittee shall provide written notice to the Chief, Bureau of Environmental Protection one (1) month prior to the disposal of any sturgeon.

5. Notwithstanding any other requirements in this permit, the permittee shall also comply with all applicable Water Quality Regulations promulgated by the Interstate Sanitation Commission including Sections 1.01 and 2.05 (f) as they relate to oil and grease.

6. It is recognized that influent quality changes, equipment malfunction, acts of God, or other circumstances beyond the control of the Permittees may, at times, result in effluent concentrations exceeding the permit limitations despite the exercise of appropriate care and maintenance measures, and corrective measures by the permittees. The permittees, either individually or jointly, may come forward to demonstrate to the DEC that such circumstances exist in any case where effluent concentrations exceed those set forth in this permit. The DEC, however, is not obligated to wait for, or solicit, such demonstrations prior to the initiation of any enforcement proceedings, nor must it accept as valid on its face the statements made in any such demonstration.

In the event of non-compliance attributable to only one facility, DEC will initiate enforcement proceedings against the permittee responsible for such facility.

DEC shall not initiate enforcement proceedings concurrently against both the Permittees, unless DEC has been unable to identify the non-complying facility. If DEC seeks to enforce in an administrative or judicial proceeding any provision of this permit, the Permittees may raise at that time the issue of whether, under the United States Constitution, statute, or decisional law, they are entitled to a defense that their conduct was caused by circumstances beyond their control.

7. The Hudson River Settlement Agreement, dated December 19, 1980, is annexed to this permit as Appendix 2 and is incorporated herein as a condition to this permit. The Settlement Agreement satisfies New York State Criteria Governing Thermal Discharges. The Agreement for Installation of Modified Ristroph Screens at Indian Point Units 2 & 3, dated October 31, 1988 is annexed to this permit as Appendix 3 and is incorporated herein as a condition to this permit. The Agreement for Installation of Modified Ristroph Screens at Indian Point Units 2 & 3 implements Section 2.F of the Hudson River Settlement Agreement and satisfies New York State Criteria Governing Thermal Discharges.

8. All chemicals listed and/or referenced in the January 17, 1986 permit application as well as Drewgard 315, Betz Corr-Shield 736 and Nalco 8325 are approved for use. Drewgard 100 may be added so the calculated concentration shall not exceed 11 mg/l and the active ingredient E.D.T.A. shall not exceed 0.28 mg/l in the discharge canal. If use of new biocides, corrosion control chemicals or water treatment chemicals is intended, application must be made prior to use. No use will be approved that would cause exceedance of state water quality standards.

9. Beginning upon the effective date of this permit, the permittees shall submit to the NYSDEC Offices in Albany and White Plains, a copy of their Semi-Annual Effluent and Waste Disposal Reports submitted to the Nuclear Regulatory Commission.

10. Permittee will (at Permittee's option) submit a report to analyze the suitability of continuous chlorine monitoring for compliance purposes. The report will compare results of continuous monitor to results of grab sampling program (for total residual chlorine). Within 60 days from receipt of the report, DEC shall either (a) approve the report's conclusions and recommendations and initiate any appropriate permit modification requested by the permittees or (b) provide the permittees with the detailed technical reasons for rejection. If DEC fails to meet this 60-day deadline, the Department shall initiate a permit modification to require grab samples at least once every 30 minutes during condenser chlorination.

11. The data, results and information being generated pursuant to aquatic studies and analyses and impact mitigation programs being conducted at this Facility under the terms of the Hudson River Settlement Agreement, dated December 19, 1980, shall constitute sufficient grounds for the applicant or the DEC to seek modification of this permit under 6 NYCRR 621.13.

SPECIAL CONDITIONS - BEST MANAGEMENT PRACTICES

1. The permittee shall develop a modification to the Best Management Practices (BMP) plan to prevent, or minimize the potential for, release of significant amounts of toxic or hazardous pollutants to the waters of the State through plant site runoff, spillage and leaks; sludge or waste disposal; and storm water discharges including, but not limited to, drainage from raw material storage. Completed BMP plans shall be submitted by EDM + 6 Months to the Regional Water Engineer at the address shown on the Recording, Reporting and Additional Monitoring Requirements. The BMP plan shall be implemented within 6 months of submission, unless a different time frame is approved by this Department.

2. Subsequent modifications to or renewal of this permit does not reset or revise the deadline set forth in (1) above, unless a new deadline is set explicitly by such permit modification or renewal.

3. The permittee shall review all facility components or systems (including material storage areas; in-plant transfer, process and material handling areas; loading and unloading operations; storm water, erosion, and sediment control measures, process emergency control systems; and sludge and waste disposal areas) where toxic or hazardous pollutants are used, manufactured, stored or handled to evaluate the potential for the release of significant amounts of such pollutants to the waters of the State. In performing such an evaluation, the permittee shall consider such factors as the probability of equipment failure or improper operation, cross-contamination of storm water by process materials, settlement of facility air emissions, the effects of natural phenomena such as freezing temperatures and precipitation, fires, and the facility's history of spills and leaks. For hazardous pollutants, the list of reportable quantities as defined in 40 CFR, Part 117 may be used as a guide in determining significant amounts of releases. For toxic pollutants, the relative toxicity of the pollutant shall be considered in determining the significance of potential releases.

   The review shall address all substances present at the facility that are listed as toxic pollutants under Section 307(a)(1) of the Clean Water Act or as hazardous pollutants under Section 311 of the Act or that are identified as Chemicals of Concern by the Industrial Chemical Survey.

4. Whenever the potential for a significant release of toxic or hazardous pollutants to State waters is determined to be present, the permittee shall identify Best Management Practices that have been established to minimize such potential releases. Where BMPs are inadequate or absent, appropriate BMPs shall be established. In selecting appropriate BMPs, the permittee shall consider typical industry practices such as spill reporting procedures, risk identification and assessment, employee training, inspections and records, preventive maintenance, good housekeeping, materials compatibility and security. In addition, the permittee may consider structural measures (such as secondary containment and erosion/sediment control devices and practices) where appropriate.

5. Development of the BMP plan shall include sampling of waste stream segments for the purpose of toxic "hot spot" identification. The economic achievability of effluent limits will not be considered until plant site "hot spot" sources have been identified, contained, removed or minimized through the imposition of site specific BMPs or application of internal facility treatment technology. For the purposes of this permit condition, a "hot spot" is a segment of an industrial facility; including but not limited to soil, equipment, material storage areas, sewer lines etc., which contributes elevated levels of problem pollutants to the wastewater and/or storm water collection system of that facility. For the purposes of this definition, problem pollutants are substances for which treatment to meet a water quality or technology requirement may, considering the results of waste stream segment sampling, be deemed unreasonable. For the purposes of this definition, an elevated level is a concentration or mass loading of the pollutant in question which is sufficiently higher than the concentration of that same pollutant at the compliance monitoring location so as to allow for an economically justifiable removal and/or isolation of the segment and/or B.A.T. treatment of wastewaters emanating from the segment.

The BMP plan shall be documented in narrative form and shall include any necessary plot plans, drawings or maps. Other documents already prepared for the facility such as a Safety Manual or a Spill Prevention, Control and Countermeasure (SPCC) plan may be used as part of the plan and may be incorporated by reference. USEPA guidance for development of storm water elements of the BMP is available in the September 1992 manual "Storm Water Management for Industrial Activities," USEPA Office of Water Publication EPA 832-R-92-006 (available from NTIS, (703)487-4650, order number PB 92235969). A copy of the BMP plan shall be maintained at the facility and shall be available to authorized Department representatives upon request. As a minimum, the plan shall include the following BMP's:

a. BMP Committee	e. Inspections and Records	i. Security
b. Reporting of BMP Incidents	f. Preventive Maintenance	j. Spill prevention & response
c. Risk Identification & Assessment	g. Good Housekeeping	k. Erosion & sediment control
d. Employee Training	h. Materials Compatibility	l. Management of runoff

7. The BMP plan shall be reviewed annually and shall be modified whenever: (a) changes at the facility materially increase the potential for significant releases of toxic or hazardous pollutants, (b) actual releases indicate the plan is inadequate or (c) a letter from the Regional Water Engineer highlights inadequacies in the plan..

8. Facilities with Petroleum and/or Chemical Bulk Storage (PBS and CBS) Areas:
Compliance must be maintained with all applicable regulations including those involving releases, registration, handling and storage (6NYCRR 595-599) and (6NYCRR 612-614). Stormwater discharges from handling and storage areas should be eliminated where practical.

a. Spill Cleanup - All spilled or leaked substances must be removed from secondary containment systems as quickly as practical and in all cases within 24 hours. The containment system must be thoroughly cleaned to remove any residual contamination which could cause contamination of stormwater and the resulting discharge of pollutants to waters of the State. Following spill cleanup the affected area must be completely flushed with clean water three times and the water removed after each flushing for proper disposal in an on-site or off-site wastewater treatment plant permitted to discharge such wastewater. Alternatively, the permittee may test the first batch of stormwater following the spill cleanup to determine discharge acceptability. If the water contains no pollutants it may be discharged. Otherwise it must be disposed of as noted above. See *Discharge Monitoring* below for the list of parameters to be sampled for.

b. Discharge Operation - Stormwater must be removed before it compromises the required containment system capacity. Each discharge may only proceed with the prior approval of the permittee staff person responsible for ensuring compliance with this permit. Bulk storage secondary containment drainage systems must be locked in a closed position except when the operator is in the process of draining accumulated stormwater. Transfer area secondary containment drainage systems must be locked in a closed position during all transfers and must not be reopened unless the transfer area is clean of contaminants. Stormwater discharges from secondary containment systems should be avoided during periods of precipitation. A logbook shall be maintained on-site noting the date, time and personnel supervising each discharge.

c. Discharge Monitoring of Bulk Storage Secondary Containment Systems and Tank Hydrotest Waters - *This paragraph only applies to those bulk storage containment system outlets which are not identified in the SPDES permit as an outfall with explicit effluent limitations.* Prior to each discharge of contained waters, such waters must be screened for contamination*. The method of screening shall be developed by the permittee as part of the overall Best Management Practices Plan. Examples of screening methods include inspection for any visible evidence of contamination for non-fuel petroleum secondary containment and volatile gas meters for petroleum fuel or volatile materials secondary containment. If the screening indicates contamination, the permittee must collect and analyze a representative sample** of the contained liquid and contact the regional water engineer (or the regional water engineer's authorized representative) to determine if the contained liquid may be discharged.

d. Discharge Monitoring of Transfer Area Secondary Containment Systems - *This paragraph only applies to those transfer area containment system outlets which are separate from bulk storage containment system outlets and are not identified in the SPDES permit as an outfall with explicit effluent limitations.* The first discharge* following any spill or leak must be sampled for flow, pH, the substance(s) transferred in that area and any other pollutants believed to be present**.

e. Discharge Reporting - Results of analytical monitoring required above must be submitted to the Department by appending them to the corresponding discharge monitoring report (DMR). Failure to perform the required discharge monitoring and reporting shall constitute a violation of the terms of the SPDES permit.

F. Prohibited Discharges - The following discharges are prohibited unless specifically authorized elsewhere in this SPDES permit or unless proper notification is provided to the department and the department determines such discharge may proceed without modification to this permit; spills or leaks, tank bottoms, maintenance wastewaters, wash waters where detergents or other chemicals have been used, contained fire fighting runoff, fire training water contaminated by contact with pollutants or containing foam or fire retardant additives, and, unnecessary discharges of water or wastewater into secondary containment systems. An example of a necessary discharge could be the addition of steam to prevent bulk storage containment area sump pumps from freezing during cold weather. In all cases, any discharges which contain a visible sheen, foam, or odor, or may cause or contribute to a violation of water quality are prohibited.

* Discharge includes stormwater discharges and snow and ice removal. If applicable, a representative sample of snow and/or ice should be collected and allowed to melt prior to assessment.

** If the stored substance is a petroleum fuel (i.e. fuel oil, gasoline, kerosene, etc.), then the discharge should be sampled for oil & grease, benzene, ethylbenzene, naphthalene, toluene and total xylenes. If the stored substance(s) are listed in Tables 6-8 of application form NY-2C sampling is required. If the substance(s) are listed in NY-2C Tables 9-10 sampling for appropriate indicator parameters may be required, e.g., substituting BOD5 for methanol, substituting toxicity testing for demeton. The volume of discharge may be calculated by measuring the depth of water within the containment area times the wetted area converted to gallons or by other suitable methods. Form NY-2C is available on the NYSDEC web site. Contact the facility inspector for further guidance.

. nition of Daily Average and Daily Maximum

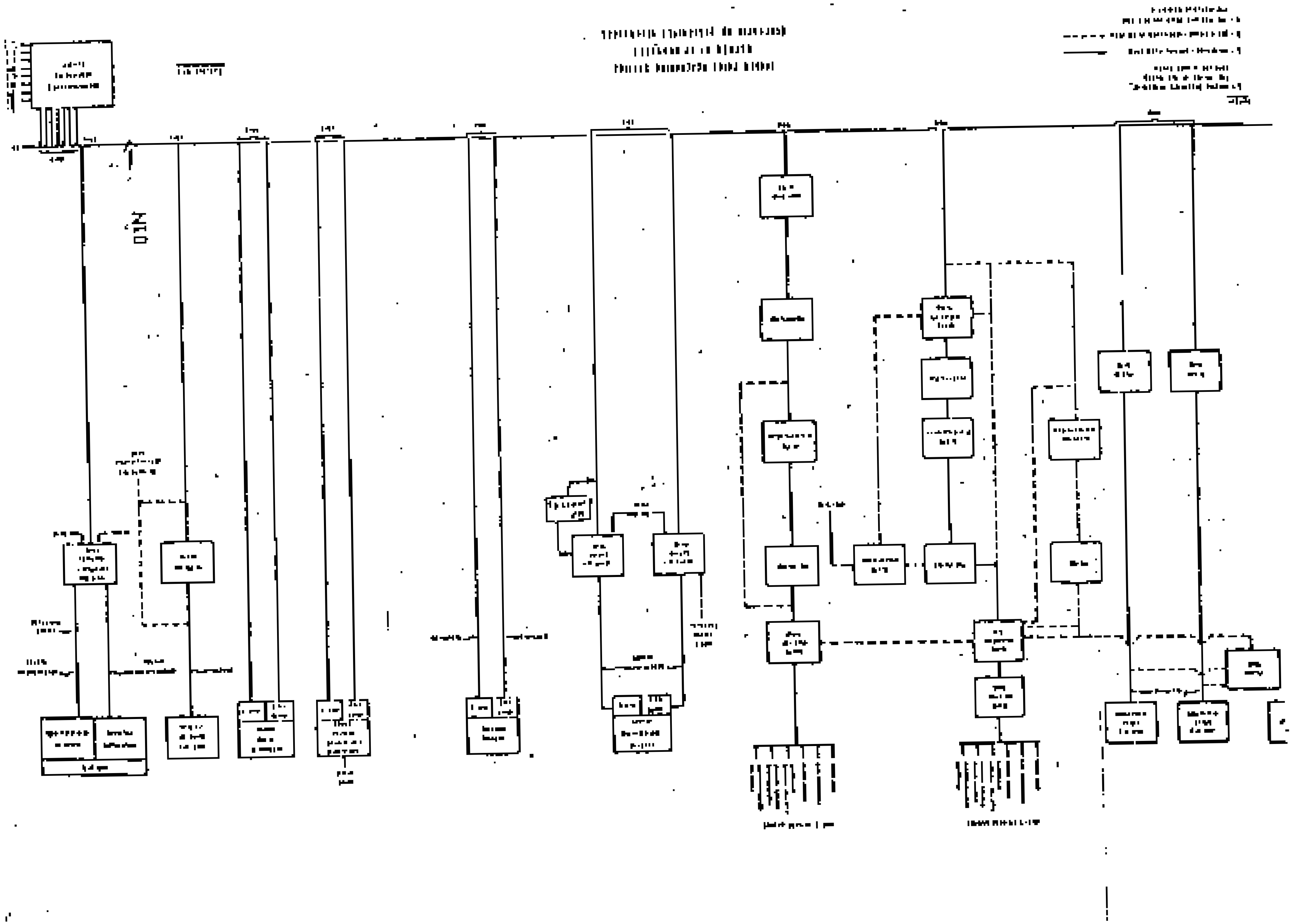
The daily average discharge is the total discharge by weight or in other appropriate units as specified herein, during a calendar month divided by the number of days in the month that the production or commercial facility was operating. Where less than daily sampling is required by this permit, the daily average discharge shall be determined by the summation of all the measured daily discharges in appropriate units as specified herein divided by the number of days during the calendar month when the measurements were made.

The daily maximum discharge means the total discharge by weight or in other appropriate units as specified herein, during any calendar day.

Monitoring Locations

Permittee shall take samples and measurements to meet the monitoring requirements at the location(s) indicated below:

(Show locations of outfalls with sketch or flow diagram as appropriate). The sampling for the internal waste streams 001A thru 001L shall be taken in the internal waste streams before entering the circulating cooling water discharge canal.



~~FINAL~~ SCHEDULE OF COMPLIANCE FOR EFFLUENT LIMITATIONS

(a) Permittee shall achieve compliance with the effluent limitations specified in this permit for the permitted discharge(s) ccordance with the following schedule:

Action Code	Outfall Number(s)	Compliance Action	Due Date
04	001A	Respondent shall begin construction of the "Sanitary Waste Pipeline Connection from the Indian Point Generating Facility to the Village of Buchanan.	4/1/88
08	001A	Respondent shall complete construction of the "Sanitary Waste Pipeline Connection from the Indian Point Generating Facility to the Village of Buchanan."	12/1/88
27	001A	Respondent shall cease discharges from the Sanitary Waste Treatment Plant, Outfall 001A, at the Indian Point Generating Facility.	1/1/89

The permittee shall comply with all terms and conditions of the orders on consent dated July 17, 1986 and August 20, 1987 , described as attachments "A & B". Said terms and conditions are incorporated, herein, by reference.

(b) The permittee shall submit to the Department of Environmental Conservation the required document(s) where a specific action is required in (a) above to be taken by a certain date, and a written notice of compliance or noncompliance with each of the above schedule dates, postmarked no later than 14 days following each elapsed date. Each notice of noncompliance shall include the following information:

1. A short description of the noncompliance,

2. A description of any actions taken or proposed by the permittee to comply with the elapsed schedule requirement out further delay;

3. A description of any factors which tend to explain or mitigate the noncompliance; and

4. An estimate of the date permittee will comply with the elapsed schedule requirement and an assessment of the probability that permittee will meet the next scheduled requirement on time.

HEDULE OF COMPLIANCE FOR EFFLUENT LIMITATIONS (continued)

(c) The permittee shall submit copies of the written notice of compliance or noncompliance required herein to the following offices:

Chief, Compliance Section
New York State Department of Environmental Conservation
50 Wolf Road
Albany, New York 12233

Regional Water Engineer, Region 3
New York State Department of Environmental Conservation
202 Mamaroneck Avenue
White Plains, NY 10601

The permittee shall submit copies of any engineering reports, plans of study, final plans, as-built plans, infiltration-inflow ...es, etc. required herein to the New York State Department of Environmental Conservation Regional Office specified ...ove unless otherwise specified in this permit or in writing by the Department or its designated field office.

MONITORING, RECORDING AND REPORTING

a) The permittee shall also refer to the General Conditions (Part II) of this permit for additional information concerning monitoring and reporting requirements and conditions.

b) The monitoring information required by this permit shall be:

☒ Summarized, signed and retained for a period of three years from the date of sampling for subsequent inspection by the Department or its designated agent.

☒ Summarized and reported by submitting completed and signed Discharge Monitoring Report forms once every 1 month(s) to the locations specified below. Blank forms available at department offices listed below.

The first report will be due no later than November 28, 1987

Thereafter, reports shall be submitted no later than the 28th of the following month(s) each month.

Department of Environmental Conservation
Regional Water Engineer, Region 3
202 Mamaroneck Avenue
White Plains, NY 10601

Westchester County Health Department
112 East Post Road
White Plains, NY 10601

Department of Environmental Conservation
Division of Water
50 Wolf Road,
Albany, New York 12233

Interstate Sanitation Commission
ATTN: Mr. Thomas R. Glenn, Jr.
Director and Chief Engineer
10 Columbus Circle
New York, NY 10019

☒ (Applicable only if checked)

Dr. Richard Baker, Chief
Permit Administration Branch
Planning & Management Division
USEPA Region II, 26 Federal Plaza
New York, New York 10278

c) XXXXXXXXX, Monthly Wastewater Treatment Plant Operator's Reports should be submitted to the Regional Engineer and County Health Department or County Environmental Control Agency specified above (outfall 001A only)

d) Monitoring must be conducted according to test procedures approved under 40 CFR Part 136, unless other test procedures have been specified in this permit.

e) If the permittee monitors any pollutant more frequently than required by the permit, using test procedures approved under 40 CFR 136 or as specified in the permit, the results of this monitoring shall be included in the calculations and recording of the data on the Discharge Monitoring Reports.

f) Calculations for all limitations which require averaging of measurements shall utilize an arithmetic mean unless otherwise specified in this permit.

g) Unless otherwise specified, all information recorded on the Discharge Monitoring Report shall be based upon measurements and sampling carried out during the most recently completed reporting period.

h) On or after April 1, 1984, any laboratory test or sample analysis required by this permit for which the State Commissioner of Health issues certificates of approval pursuant to section five hundred two of the Public health Law shall be conducted by a laboratory which has been issued a certificate of approval. Inquires regarding laboratory certification should be sent to the Laboratory Certification/Quality Assurance Group, New York State Health Department Center for Laboratories and Research, Division of Environmental Sciences, The Nelson A. Rockefeller Empire State Plaza, Albany, New York 12201

Memorandum of Agreement
Between
New York State Department of Environmental Conservation
and
the Hudson River Utilities

1. This Memorandum of Agreement (MOA) is entered into by the New York State Department of Environmental Conservation (Department) with Consolidated Edison of New York, Inc. (Consolidated Edison), and Power Authority of the State of New York (Power Authority), Orange and Rockland Utilities, Inc. (O and R), and Central Hudson Gas and Electric Corp. (CH) in accordance with the Department's certification pursuant to Section 401 of the Clean Water Act and to supply the appropriate conditions "Biological Monitoring and Reporting" of the SPDES discharge permit numbers:

NY 000 4472	Consolidated Edison's Indian Point Station Units 1 & 2
NY 002 7065	The Power Authority's Indian Point Station Unit 3
NY 000 8010	Orange and Rockland Utilities' Bowline Point Station
NY 000 8231	Central Hudson's Roseton Station,

and in accordance with the "Biological Monitoring Program" as provided for in Section 2.J and Attachment V to the Hudson River Settlement Agreement entered into December 19, 1980 (Settlement Agreement).

2. This MOA is to embody the agreement of the Utilities to conduct monitoring program studies as described in the Settlement Agreement. Specific studies will be carried out in accordance with work scopes approved by the Department. Nothing contained in this MOA shall cause the Utilities to perform activities or incur expenses in excess of or less than the amount specified in the settlement agreement. Any further studies necessary to fulfill the dollar value of the Utilities' monitoring obligations will be conducted only with the prior written approval of DEC.

3. The Utilities agree to use their best efforts to conduct fully the biological monitoring program as specified in the Settlement Agreement. The Department acknowledges that the Utilities will not be deemed to be in non-compliance with the Settlement Agreement or any Condition of any applicable discharge permit or Section 401 Certification if the full complement of all biomonitoring cannot be completed within the original calendar year for reasons beyond the reasonable control of the Utilities. However, should the full complement of biomonitoring not be completed within the original year, at the sole discretion of DEC, either the time to complete such studies shall be extended or the unexpended funds shall be used to supplement the biomonitoring program in the subsequent year.

4. The Department and the Utilities hereby agree that the study programs may be modified at any time by written agreement of the Department and the Utilities to fulfill the objectives of the study, provided that any cost savings which accrue through such modifications be redirected to other studies as appropriate.

5. Reports based on these studies and an accounting of funds expended will be submitted within six months of the completion of component studies and no later than June 30 of the subsequent year unless an extended schedule is mutually agreed upon by the Department and the Utilities.

6. The term of this MOA shall be from the expiration of the permit currently in force until the expiration date of this permit, after which time this MOA shall be of no further force or effect except for completion of reports, accountings, or studies identified in paragraphs 3 to 5.

Signatures

Signatures	Con Edison	Date
	Orange & Rockland	Date
	Central Hudson	Date
	Power Authority	Date
	Niagara Mohawk	Date
	NYSDEC	Date

New York State Department of Environmental Conservation
Division of Environmental Permits, Room 538
50 Wolf Road, Albany, New York 12233-1750
Phone: (518) 457-2224 FAX: (518) 457-5965

John P. Cahill
Commissioner

September 26, 1997

Facility Information
INDIAN POINT STATION #1 2 & 3
SPDES #: NY 0004472
DEC #: 3-5522-00011/00004
CORTLANDT (T), WESTCHESTER CO.

DENNIS DUNNING
CON ED/PASNY
123 MAIN ST.
WHITE PLAINS, NY 10601-

Dear Permittee:

This is to inform you that pursuant to Article 17, Title 8 (State Pollution Discharge Elimination System) and Article 70 (Uniform Procedures) of the Environmental Conservation Law (ECL), and 6NYCRR Parts 621 and 757, the Department has made a determination to modify the permit referenced above, in conformance with requirements of the "Discharge Notification Act" (§ 17-0815-a of the ECL). This new section of law, which became effective October 1, 1996, requires you to post a sign at each point of wastewater discharge to surface waters and to provide a public repository for Discharge Monitoring Reports(DMR's) required by the SPDES permit.

The enclosed permit modification page, which is to be appended to your existing permit, contains the specifics for: sign design, language, and posting; repository availability; and the compliance time frame.

The "Discharge Notification Act" also provides the Department with discretion to waive all or part of the requirements of the sign posting provisions if it is determined that a sign can not be located so as to satisfy the intent of the Act. Enclosed is a Waiver Request form that identifies the four circumstances in which the Department may determine that your discharge point is eligible for such a waiver. If you think you may qualify for a waiver, you must complete the Waiver Request form for each outfall by checking the appropriate box(es) and providing written justification to substantiate your waiver request.

The modification will become effective October 31, 1997 unless you either submit a completed Waiver Request form to the Department before the effective date, or should you object to this permit modification on other grounds, you submit a written statement giving supporting reasons why the permit should not be modified, or to request a hearing or both. Such a submission or request must be made within 15 calendar days of the date of this letter.

Completed Waiver Request forms, statements, and requests for hearing are to be addressed to New York State Department of Environmental Conservation, Bureau of Water Permits, 50 Wolf Road, Albany, New York 12233-3505.

If you require further information please contact Joseph DiMura at (518) 457-0657 or at the address in the preceding paragraph.

Sincerely,

William R. Adriance

William R. Adriance
Chief Permit Administrator

Enclosures
cc: RPA - Region 3
RWE - Region 3

DISCHARGE NOTIFICATION REQUIREMENTS

a) Within ninety days after the effective date of this permit modification, the permittee shall install and maintain identification signs at all outfalls to surface waters listed in this permit. The sign(s) shall be conspicuous, legible and in as close proximity to the point of discharge as is reasonably possible while ensuring the maximum visibility from the surface water and shore. The signs shall be installed in a manner that poses minimal hazard to navigation, bathing or other water related activities. If the public has access to the water from the land in the vicinity of the outfall, an identical sign shall be posted to be visible from the direction approaching the surface water.

The signs shall have minimum dimensions of eighteen inches by twenty four inches (18" x 24") and shall have white letters on a green background and contain the following information:

N.Y.S. PERMITTED DISCHARGE POINT

SPDES PERMIT No.: NY__________

OUTFALL No. : ____

For information about this permitted discharge contact:

Permittee Name: ____

Permittee Contact: ____

Permittee Phone: ( ) - ### - ####

OR:

NYSDEC Division of Water Regional Office Address :

NYSDEC Division of Water Regional Office Phone: ( ) - ### -####

b) If upon the effective date of this modification, the permittee has installed signs that include the information required by § 17-0815-a(2)(a), but do not meet the specifications listed above, the permittee may continue to use the existing signs for a period of up to five years, after which the signs shall comply with the specifications listed above.

c) The permittee shall periodically inspect the outfall identification signs in order to insure that they are maintained, are still visible and contain information that is current and factually correct.

d) Within ninety days after the effective date of this permit modification, the permittee shall provide for public review at a repository accessible to the public, copies of the Discharge Monitoring Reports (DMRs) as required by the **RECORDING, REPORTING AND ADDITIONAL MONITORING REQUIREMENTS** page of this permit. This repository shall be open to the public at a minimum of normal daytime business hours. The repository may be at the business office repository of the permittee or at an off-premises location of its choice (such location shall be the village, town, city or county clerk's office, the local library or other location as approved by the Department.) In accordance with the **RECORDING, REPORTING AND ADDITIONAL MONITORING REQUIREMENTS** page of your permit, each DMR shall be maintained on record for a period of three years.

NEW YORK STATE DEPARTMENT OF ENVIRONMENTAL CONSERVATION
DIVISION OF WATER

DIRECTORY OF REGIONAL OFFICE ADDRESSES AND PHONE NUMBERS

FOR USE ON "DISCHARGE NOTIFICATION ACT" SIGNS

REGION	DIVISION OF WATER (DOW) REGIONAL OFFICE
1	Building 40 - SUNY @ Stony Brook Stony Brook, New York 11790-2356 Tel. (516) 444-0405
2	1 Hunters Point Plaza, 47-40 21st St. Long Island City, New York 11101-5407 Tel. (718) 482-4933
3	200 White Plains Road, 5th Floor Tarrytown, New York 10591-5805 Tel. (914) 332-1835 Ext. 359
4	1150 North Westcott Road Schenectady, New York 12306-2014 Tel. (518) 357-2045
5	Hudson Street Extension Warrensburg, NY 12885-0220 Tel. (518) 623-3671
6	State Office Building 207 Genesee Street Utica, New York 13501-2885 Tel. (315) 793-2554
7	615 Erie Blvd. West Syracuse, New York 13204-2400 Tel. (315) 426-7500
8	6274 East Avon-Lima Road Avon, New York 14414-9519 Tel. (716) 226-2466
9	270 Michigan Avenue Buffalo, New York 14202-2999 Tel. (716) 851-7070

[illegible]

WAIVERS FROM REQUIREMENTS OF THE SPDES PERMIT MODIFICATION FOR DISCHARGE NOTIFICATION REQUIREMENTS:

In order to apply for a waiver pursuant to the provisions specified in ECL § 17-0815-1 a. Discharge Point Signs, the permittee must check the following boxes as applicable *and* provide written justification in the space provided below. Use additional pages, as necessary, to request waivers for additional outfalls with different explanations.

☐ Outfall(s) to surface water listed in my SPDES permit are composed exclusively of storm water runoff.

☐ There are circumstances for outfall(s) to surface water listed in my SPDES permit such that the sign(s) cannot be reasonably maintained.

☐ The placement of signs for outfall(s) to surface waters listed in my SPDES permit would be inconsistent with another statute.

☐ The placement of signs for outfall(s) to surface waters listed in my permit can not be so located as to provide a public purpose.

Permittee Name: ______________________ Contact Name: ______________________

SPDES No.: NY__________ Outfall Number(s): ____________ Phone: ____________

EXPLANATION:

This request shall be submitted to the address listed below by the effective date of the permit modification:

Bureau of Water Permits, Room 338
New York State Department of Environmental Conservation
50 Wolf Road
Albany, New York 12233-3505

New York State Department of Environmental Conservation
Region 3
21 South Putt Corners Road
New Paltz, NY 12561-1696
914-255-5453

May 1§, 1992

Thomas C. Jorling
Commissioner

MR JOHN R KELLY
NEW YORK POWER AUTHORITY
123 MAIN STREET
WHITE PLAINS NY 10601

Re: Zebra Mussel Control
Indian Point Generating Stations 1, 2, and 3
SPDES #NY-0004472
DEC # 3-5522-11/4-0

PERMIT MODIFICATION

Dear Mr. Kelly:

This letter approves your firm's April 20, 1992 request (as supplemented May 7, 1992) to modify the above State Pollutant Discharge Elimination System permit under the Department's generic permit modification for zebra mussel control. The treatment program shall be undertaken in accordance with the effluent limitations, monitoring requirements and special conditions as set forth in the enclosed attachment # C. This approval should be attached to your existing permit dated August 28, 1987, which expires October 1, 1992.

Please make all involved facility staff aware of these requirements and provide a full copy of the modification to your counterpart at Consolidated Edison. Thank you for your attention to this matter. If you have any questions you may contact Mr. David Reid of this office or Mr. Joseph Marcogliese at our White Plains office (914)761-6660.

Sincerely,

Margaret E. Duke

Margaret E. Duke
Regional Permit Administrator
Region 3

MED/DJR/dah
Enclosure

cc: w/enclosure
C. Manfredi/J. Marcogliese/E. Zicca
R. Hannaford-BWFD
Westchester County DOH
EPA-NY, L. Livingston
EPA-NJ, R. Spear
Interstate Sanitation Commission

CONTROLLED

COPY # 8

Clam-Trol (7/91)

SPDES No.: NY ______

Part 1. Attachment #: ______

EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning May 15, 1992

and lasting until October 1, 1992

the discharges from the permitted facility shall be limited and monitored by the permittee as specified below:

Outfall Number & Effluent Parameter	Discharge Limitations Daily Avg.	Daily Max.	Units	Minimum Monitoring Requirements Measurement Frequency	Sample Type
Outfall(s) 001					
Betz Clam-Trol CT-1 (whole product)	N/A	0.2	mg/l	Duration of chemical application & discharge	Multiple Grab*

* For purpose of this authorization, multiple grab is defined as individual grab samples collected at three hour intervals during the duration of chemical addition and discharge.

Special Conditions

Betz Clam-Trol CT-1 program for zebra mussel control, application submitted by letter application dated 04/30/92 DEC Region 3 New Paltz Office, is approved with the following conditions:

1. The effluent concentrations at the discharge shall not exceed 10 ug/l (ppb) of quaternary ammonium compounds and 6 ug/l (ppb) of dodecycguanidine hydrochloride. For Betz Clam-Trol CT-1, these limitations will be achieved by limiting effluent whole product concentrations.
2. Clam-Trol CT-1 detoxification with bentonite clay or other Department approved adsorption medium is required for all affected discharge waste streams throughout the treatment period.
3. Each individual zebra mussel control treatment is limited to a maximum of 24 hours duration.
4. Treatments for zebra mussel control shall be limited to a maximum of four treatments annually. Treatments shall be separated by at least 45 days.
5. Caged fish studies are required to be conducted during the discharge of the molluscicide. Sample study protocols are available from the Department's Division of Fish and Wildlife. Specific caged fish study protocols must be approved by the Department prior to commencement of the zebra mussel control program.
6. Records of product dosage concentration, effluent flow and effluent concentration of product during addition and discharge must be maintained. The flow shall be measured at the frequency specified for flow elsewhere in this permit or at the frequency of the parameter specified above, whichever is more frequent.
7. The Regional Water Engineer shall be notified not less than 48 hours before initiation of a zebra mussel control program.
8. Reports describing caged fish studies shall be sent to New York State Department of Environmental Conservation, Division of Fish and Wildlife, Standards and Criteria Unit - Room 530, 50 Wolf Road, Albany, New York 12233-4756, within 60 days following each individual zebra mussel control treatment.
9. Reports describing the results of the effectiveness of the zebra mussel control program and the effluent analyses for Betz Clam-Trol CT-1 shall be submitted to the Regional Water Engineer, NYSDEC, within 60 days following each chemical treatment.
10. This permit modification is issued based on the best environmental and aquatic toxicity information available at this time. This authorization is subject to modification or revocation any time new information becomes available which justifies such modification or revocation.

D. GRAY

New York State Department of Environmental Conservation
50 Wolf Road, Albany, New York 12233-3505

RECEIVED

EARTH DAY 25
1995
ENVIRONMENTAL PARTNERS

Michael D. Zagata
Commissioner

August 2? 1995

Mr. John W. Blake, Ph.D., Director
Environmental Division
New York Power Authority
123 Main Street
White Plains, New York 10601

RE: Chemical Use Request
Indian Point No. 3
NY 000 4472

Dear Mr. Blake:

Your June 2, 1995 request for permission to use Ethanolamine (ETA) has been reviewed. This chemical is approved for use as specified in your application. Use of this chemical must not cause or contribute to a violation of New York State Water Quality Standards.

Should you have any questions, please call me at (518) 457-1632.

Sincerely,

Paul J. Kolakowski

Paul J. Kolakowski, P.E.
Environmental Engineer II
Physical Systems Section

PJK:mak
cc: Arthur Crawford, Region 3

New York State Department of Environmental Conservation
50 Wolf Road, Albany, New York 12233-3505

March 8, 1995

Mr. John W. Blake, Ph.D.
Director, Environmental Division
New York Power Authority
123 Main Street
White Plains, New York 10601

RECEIVED
MAR 13 1995
NYPA ENV.

RE: Continuous Chlorine Analyzer
Indian Point Unit No. 3
NY 000 4472

Dear Mr. Blake:

Your January 19, 1995 letter submitted in accordance with additional requirement No. 10 of the SPDES permit has been reviewed. The submittal demonstrated that the continuous chlorine monitoring equipment was not reliable. Therefore, monitoring for condenser chlorination shall be conducted by analyzing grab samples ..n at least once every 30 minutes during each chlorination ..d (Footnote q). Samples shall be taken at least once daily ..ing low level service water chlorination (Footnote r).

Modification of the permit will not be necessary since these monitoring requirements are already part of the permit. Should you have any questions, please call me at (518) 457-1632.

Sincerely,

Paul J. Kolakowski, P.E.
Environmental Engineer II
Physical Systems Section

PJK:sj

cc: Arthur Crawford, Region 3

New York State Department of Environmental Conservation
Division of Environmental Permits, 4th Floor
625 Broadway, Albany, New York 12233-1750
Phone: (518) 402-9167 • **FAX:** (518) 402-9168
Website: www.dec.state.ny.us

Erin M. Crotty
Commissioner

J Fulton

2[illegible] February 20[illegible]

ENTERGY NUCLEAR INDIAN POINT 2, LLC
MICHAEL R KANSLER
440 HAMILTON AVE
WHITE PLAINS, NY 10601

Re: Department Initiated Permit Modification
DEC ID: 3-5522-00011/000[illegible]
SPDES Number: NY 0004472

Dear Permittee:

The purpose of this correspondence is to notify you of a Department initiated modification to the above-referenced State Pollutant Discharge Elimination System (SPDES) permit. This modification is undertaken in accordance with the provisions of the Uniform Procedures Act (6 NYCRR 621.14(a)(4)) and is due to the amendment of the existing regulation governing the administration of SPDES permits (6 NYCRR 750). The amendments incorporate provisions of the "Part II General Conditions" supplement that serves as an additional set of conditional requirements to your SPDES permit. These amendments may be found in the enclosed copy of 6 NYCRR 750 in Section 750-2, entitled "Operating in Accordance with a SPDES Permit". You may also access this regulation from the internet on the Department's website at http://www.dec.state.ny.us/website/regs/750a.htm for html format or http://www.dec.state.ny.us/website/dow/part750.pdf for a two-sided format suitable for binding and copying.

The amendment of 6 NYCRR 750 duplicates many of the provisions of the "Part II General Conditions" supplement, and includes some revisions and additions to those conditions. The following is a general list of locations within section of 6 NYCRR 750-2 that contain new and significant information pertaining to your permit.

- 750-2.1 General Provisions of a SPDES Permit
  (b), (h), and (k)
- 750-2.3 Inspection and Entry
  (f)
- 750-2.4 Operator and Permittee Liability
  750-2.5 Routine Monitoring, Recording, and Reporting
  [illegible]
  [illegible]
  [illegible]
  [illegible]
- 750-2.6 Special Reporting Requirements for Dischargers that are not POTWs
- 750-2.7 Incident Reporting
- 750-2.8 Disposal System Operation and Quality Control

(a) (1), (2), (4), (5), (6)
(e) (7)
(h)
(e)
(i)

- 750-2.9 Additional Conditions Applicable to Publicly Owned Treatment Works
  (a) (2), (4)
  (b) (1), (2), (3), (4), (5), (6), (7)
  (c)
- 750-2.10 Special Provisions - New or Modified Disposal Systems or Sewage Areas
  (a), (b), (d), (e), (f), (g), (h), (i)
- 750-2.11 Closure Requirements for Disposal Systems

Also, please note that the telephone number designated by the Regional Water Engineer to receive after business hours reports (as set forth in 6 NYCRR 750-1.2(a)(73)) is now (518) 457-7362.

The Department initiated modification to your permit deletes the "Part II General Conditions" and all references to them from your permit, and further amends the permit requiring you to comply with 6 NYCRR 750-2. The specific language of the modification is contained in the attached modification page that is to be appended to your existing permit.

The Department's Uniform Procedures Act affords permittees the right to comment on Department initiated permit changes [6 NYCRR 621.14(d)]. After reviewing the content of 6 NYCRR 750-2 and its effect on your SPDES permit, should you have any objections to the permit modification, you may submit a written statement to the Department giving reasons why the permit should not be modified, request a hearing, or both. Any statement or request for hearing must be made within 15 calendar days of the mailing of this letter. Failure to submit a timely request or statement will result in the modification of your permit, becoming effective 07 March 2004.

If you have any questions on this action, please contact Andrea Sheeran at the above address, or by telephone at (518) 402-9179.

Sincerely,

William R. Adriance

William R. Adriance
Chief Permit Administrator

cc: RPA
RWE
BWP
file

New York State Department of Environmental Conservation
Division of Environmental Permits, 4th Floor
625 Broadway, Albany, New York 12233-1750
Phone: (518) 402-9167 • FAX: (518) 402-9168
Website: www.dec.state.ny.us

Erin M. Crotty
Commissioner

STATEMENT OF STATE POLLUTANT DISCHARGE ELIMINATION SYSTEM (SPDES) PERMIT MODIFICATION TO BE KEPT WITH SPDES PERMIT NUMBER NY 0004472. INDIAN POINT STATION #1 2 & 3 DEC ID 355220001100021 EFFECTIVE 07 MARCH 2004

Per Department of Environmental Conservation amendment to the regulations governing the administration of the State Pollutant Discharge Elimination System Permit, this permit is hereby modified to mandate compliance with New York State Environmental Conservation Law, 6 NYCRR Part 750 entitled State Pollutant Discharge Elimination System (SPDES) Permits.

This Department initiated modification to your permit deletes the former 'Part II General Conditions' requirements and all references to them from your permit, and further amends the permit requiring you to comply with 6 NYCRR 750-2, entitled Operating in Accordance with a SPDES Permit.

6 NYCRR , Chapter X , Disclaimer | Legend

Part 750

[2-2] See also [1-2] *This regulation became effective 05/11/03. The original Parts 750 through 758 became effective 06/20/75 and were repealed 05/11/03.*

Available DEC Guidance: The Division of Water Technical and Operational Guidance Series (TOGS)

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PART 750

SUBPART 750 - 2

OBTAINING A SPDES PERMIT

State Pollutant Discharge Elimination System (SPDES) Permits

(Statutory authority: Environmental Conservation Law (ECL) Article 3, Title 3; Article 15; Article 17, Titles 3, 5, 7, 8; Article 21; Article 70, Title 1; Article 71, Title 19. New York State Penal Code, Articles 175 and 210. Public Health Law, Section 502. Federal Water Pollution Control Act (33 U.S.C. 1251, et seq.))

Section

§ 750-2.1 General Provisions of a SPDES Permit

(a) The SPDES permit, or a true copy, shall be kept readily available for reference at the nearest wastewater treatment facility on-site.

(b) Upon issuance of a SPDES permit, a determination has been made on the basis of a submitted application, plans, or other available information, that compliance with the specified permit provisions will reasonably protect classified water use and assure compliance with applicable water quality standards. Satisfaction of permit provisions notwithstanding, if operation pursuant to the permit causes or contributes to a condition in contravention of State water quality standards or guidance values, or if the department determines that a modification of the permit is necessary to prevent impairment of the best use of the waters or to assure maintenance of water quality standards or compliance with other provisions of ECL Article 17, or the Act or any regulations adopted pursuant thereto (see section 750-1.24 of this Part), the department may require such a modification and the Commissioner may require abatement action to be taken by the permittee and may also prohibit such operation until the permit has been modified pursuant to section 621.14 of this title.

(c) The provisions of a SPDES permit are severable, and if any provision of the permit, or the application of any provision of the permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of the permit, shall not be affected thereby.

(d) If the discharge(s) permitted in a SPDES permit originate(s) within the jurisdiction of an interstate water pollution control agency, then the permitted discharge(s) must also comply with any applicable effluent standards or water quality standards promulgated by that interstate agency and as set forth in the permit for such discharge(s).

(e) The permittee must comply with all terms and conditions of the permit. Any permit noncompliance constitutes a violation of the Environmental Conservation Law and the Clean Water Act and is grounds for: enforcement action; for permit suspension, revocation or modification; and for denial of a permit renewal application.

(f) Where the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application or in any report to the Department, the permittee shall promptly submit such facts or corrected information to the regional water engineer.

(g) It shall not be a defense, for a permittee in an enforcement action, that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

(h) The filing of a request by the permittee for a permit modification, termination, transfer, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

(i) The permittee shall furnish to the department, within a reasonable time as set forth in the department request, any information that the department may request to determine whether cause exists for modifying, suspending, or revoking a SPDES permit, or to determine compliance with the permit. The permittee shall also furnish to the department, upon request, copies of records required to be kept by the permittee.

(j) Nothing in a SPDES permit relieves the permittee from a requirement to obtain any other permits required by law.

(k) Discharges authorized by a SPDES permit as defined in subdivision 1.2(a) of this Part are deemed in compliance with Titles 5, 7 and 8 of Article 17 and the regulations promulgated thereunder.

§750-2.2 Exclusions

(a) The issuance of a SPDES permit by the department and the receipt thereof by the Applicant does not supersede, revoke or rescind an order on consent or modification thereof or any of the terms, conditions or requirements contained in such order or modification thereof unless specifically intended by said order or a newly issued order.

(b) The issuance of a SPDES permit does not convey any property rights in either real or personal property, or any exclusive privileges, nor does it authorize any injury to private property or any invasion of personal rights, nor any infringement of Federal, State or local laws or regulations; nor does it obviate the necessity of obtaining the assent of any other jurisdiction as required by law for the discharge authorized.

(c) A SPDES permit does not authorize or approve the construction of any onshore or offshore physical structures or facilities or the undertaking of any work in any navigable waters.

(d) Oil and hazardous substance liability. The imposition of responsibilities upon, or the institution of any legal action against the permittee under Section 311 of the Act (see section 750-1.24 of this Part) shall be in conformance with regulations promulgated pursuant to Section 311 governing the applicability of Section 311 of the Clean Water Act to discharges from facilities with NPDES permits.

§ 750-2.3 Inspection and Entry

The permittee shall allow the commissioner, the regional administrator, the applicable county health department, or their authorized representatives, upon the presentation of credentials and other documents as may be required by law, to:

(a) enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of a SPDES permit;

(b) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit, including records required to be maintained for purposes of operation and maintenance;

(c) inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under the permit;

(d) sample or monitor at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the Act or ECL, any substances or parameters at any location; and

(e) enter upon the property of any contributor of wastewater to the system under authority of the permittee's Sewer Use Law, Ordinance (municipalities) or Regulations.

(f) If any part of the permittee's sewer system or sewage treatment works is located on any property not owned by the permittee, the permittee must be able to reasonably demonstrate to the satisfaction of the Department that it has legal access to these locations or facilities and ensure that the commissioner, the regional administrator or the county health department or any authorized representative thereof, upon presentation of credentials, will have access to these locations and facilities.

§750-2.4 Operator and Permittee Liability

(a) Any person who, having any of the culpable mental states defined in Section 15.05 of the Penal Law, shall violate any of the provisions of Titles 1 through 5, 9 through 11 and 19 of Article 17 of ECL or the rules, regulations, orders or determinations of the commissioner promulgated thereto, or the terms of any permit issued thereunder, shall be guilty of a misdemeanor and, upon conviction thereof, shall be punished by a fine of not less than two thousand five hundred dollars nor more than twenty-five thousand dollars per day of violation or by imprisonment for a term of not more than one year, or by both such fine and imprisonment. If the conviction is for an offense committed after a first conviction of such person under this subdivision, punishment shall be by a fine of not more than fifty thousand dollars per day of violation, or by imprisonment for not more than two years, or by both.

(b) Any person is guilty of a Class A misdemeanor who with criminal negligence, as defined in Section 15.05 of the Penal Law,

(1) violates any provision of Titles 7 or 8 of Article 17 of ECL,

(2) violates the rules or regulations promulgated thereunder,

(3) violates any term of any permit issued thereunder,

(4) violates any requirement imposed in a pretreatment program approved pursuant to Section 402(a)(3), 402(b)(8) of the Act (see Section 750-1.24 of this Part), or approved pursuant to Titles 7 or 8 of Article 17 of ECL,

(5) violates any final administrative orders issued pursuant to Article 71 of ECL where an opportunity for a hearing is provided, or

(6) introduces into a sewer system or publicly owned treatment works any pollutant or hazardous substance:

(i) when such person knew that such introduction was likely to cause personal injury or property damage, except if that introduction was in compliance with all applicable federal, state or local requirements or permits, or

(ii) which causes the treatment works to violate any term of any permit issued under Titles 7 or 8 of Article 17 of ECL or the rules or regulations promulgated thereunder except if that introduction was in compliance with all applicable federal, state or local requirements or permits.

(c) Any person is guilty of a Class E felony who knowingly, as defined in Section 15.05 of the Penal Law,

(1) violates any provision of Titles 7 or 8 of Article 17 of ECL,

(2) violates the rules or regulations promulgated thereunder,

(3) violates any term of any permit issued thereunder,

(4) violates any requirement imposed in a pretreatment program approved pursuant to Section 402(a)(3), 402(b)(8) of the Act (see Section 750-1.24 of this Part), or approved pursuant to Titles 7 or 8 of Article 17 of this ECL,

(5) violates any final administrative orders issued pursuant to Article 71 of ECL where an opportunity for a hearing is provided, or

(6) introduces into a sewer system or publicly owned treatment works any pollutant or hazardous substance:

(i) when such person knew that such introduction was likely to cause personal injury or property damage, except if that introduction was in compliance with all applicable federal, state or local requirements or permits, or

(ii) which causes the treatment works to violate any term of any permit issued under Titles 7 or 8 of Article 17 of ECL or the rules or regulations promulgated thereunder except if that introduction was in compliance with all applicable federal, state or local requirements or permits.

(d) Any person is guilty of a Class C felony who intentionally, as defined in Section 15.05 of the Penal Law,

(1) violates

(i) any provision of Titles 7 or 8 of Article 17 of ECL,

(ii) the rules or regulations promulgated thereunder,

(iii) any term of any permit issued thereunder, or

(iv) any final administrative orders issued pursuant to this article where an opportunity for a hearing was provided, and

(2) knows at that time that he thereby places another person who is not a participant in the crime in imminent danger of death or serious bodily injury.

(3) for the purpose of paragraphs (1) and (2) of this subdivision, in determining whether a defendant who is an individual knew that his conduct placed another person in imminent danger of death or serious bodily injury:

(i) the person is responsible only for actual awareness or actual belief that he possessed; and

(ii) knowledge possessed by a person other than the defendant but not by the defendant himself may not be attributed to the defendant.

(e) For purposes of subdivisions (b), (c), and (d) of this section, a single operational upset which leads to simultaneous violations of more than one pollutant parameter shall be treated as a single violation.

(f) Any person shall be guilty of a class E felony who, with intent to deceive, makes any false material statement, representation, or certification in any application, record, report, plan or other document filed or required to be maintained pursuant to Titles 7 or 8 of Article 17 of this chapter or who intentionally falsifies, tampers with, or renders inaccurate any monitoring device or method required to be maintained pursuant to Titles 7 or 8 or Article 17 of ECL.

(g) A person who violates any of the provisions of, or who fails to perform any duty imposed by Titles 1 through 11 inclusive and Title 19 of Article 17, or the rules, regulations, orders or determinations of the commissioner promulgated thereto or the terms of any permit issued thereunder, shall be liable to a penalty of not to exceed twenty-five thousand dollars per day for each violation, and, in addition thereto, such person may be enjoined from continuing such violation as hereinafter provided. Violation of a permit condition shall constitute grounds for revocation of such permit.

§750-2.5 Routine Monitoring, Recording, and Reporting

(a) GENERAL

(1) The permittee shall comply with all recording, reporting, monitoring and sampling requirements specified in the permit.

(2) Samples and measurements taken to meet the monitoring requirements specified in a SPDES permit shall be representative of the quantity and character of the monitored discharges. Unless otherwise specified in the permit or directed by the regional water engineer in writing, the following shall apply to such sample collection:

(i) A representative sample is one that adequately reflects the actual condition of the wastewater. The most representative sample will be drawn from a point that represents the wastewater discharged. When appropriate, that point should be at a depth where the flow is turbulent and well-mixed and the likelihood of solids settling is minimal.

(ii) For all parameters except volatile organics and oil and grease, composite samples required by a SPDES permit shall be composed of a minimum of 8 grab samples, collected over the specified collection period, either at a constant sample volume for a constant flow interval or at a flow-proportional sample volume for a constant time interval. Where continuous flow monitoring equipment is not available or where effluent flows do not vary more than ten percent over the course of composite sample collection, composite samples may be composed of equal size grab samples taken at equal time intervals.

(iii) For volatile organics and oil and grease, composite samples required by a SPDES permit shall be collected as individual aliquots that must be combined in the laboratory for analysis. At least 4 (rather than 8) aliquots or grab samples should be collected over the specified collection period, either at a constant sample volume for a constant flow interval or at a flow-proportional sample volume for a constant time interval. Where flow monitoring equipment is not available or where effluent flows do not vary more than ten percent over the course of composite sample collection, composite samples may be composed of equal size grab samples taken at equal time intervals.

(iv) Grab sample means a single sample, taken over a period of time not exceeding 15 minutes.

(v) Sample collection shall be scheduled to be representative of the normal discharge. Representative sample collection schedules include schedules set at least one month prior to when the samples are to be collected. A true and accurate copy of the schedule shall be kept readily available for reference at the wastewater treatment facility and shall be provided to the department upon request. The schedule may only be changed for good cause including but not limited to sampling equipment failure and unanticipated process shutdown. Samples may be scheduled as follows:

(a) randomly;

(b) day of the week or month, provided that scheduling by day of week or month does not persistently coincide with or exclude recurrent discharges;

(c) for stormwater, based on availability of a suitable stormwater event;

(d) any other method of scheduling that is representative and acceptable to the regional water engineer.

(3) Accessible sampling locations must be provided and maintained by the permittee. New sampling locations shall be provided by the permittee if existing locations are deemed unsuitable by the department.

(4) Unless otherwise specified in the permit or directed by the regional water engineer, actual measured values of all positive analytical results obtained above the method detection limit (MDL) for all monitored parameters shall be recorded and reported, as required by the permit.

(5) For instrumentation that is not used by a certified laboratory, but which is used to measure discharges to the environment as specified in a SPDES permit, the permittee shall periodically calibrate and perform maintenance procedures to ensure accuracy of measurements. Verification of maintenance shall be logged into the record book(s) of the facility. The permittee shall notify the department's regional office in the Discharge Monitoring Report if any required instrumentation becomes inoperable. In addition, the permittee shall verify the accuracy of its measuring equipment to the department's regional office or its designated field office upon request.

(6) No person shall falsify, tamper with, or knowingly render inaccurate any monitoring device or method required to be maintained under the permit.

(b) SIGNATORIES AND CERTIFICATION

(1) All SPDES applications and reports required by a SPDES permit shall be signed as provided in 40 CFR 122.22 (see section 750-1.24 of this Part) except that, in lieu of a signature, the Department may permit the use of a unique identifier assigning responsibility for the veracity of the information contained in an application to the same person or persons that would otherwise be required to sign the application in this section. Such a document with a unique identifier shall be considered a signed document with a certifying signature and a written instrument that could subject the signatory to liability under the New York State penal law for offenses concerning perjury and false written statements pursuant to Articles 175 and 210 of said law.

(2) No person shall knowingly make any material false statement, representation, or certification in any application, record, report, plan, or other document filed or required to be maintained under this permit, including monitoring reports or reports of compliance or noncompliance. Any person who violates this subsection shall be liable for violation of ECL § 71-1933 and subject to a fine and/or imprisonment thereunder.

(3) All applications, reports, or notifications required or authorized to be made or filed by this Article or ECL Article 17, Titles 7 or 8, or by the provisions or conditions of any permit issued pursuant thereto by or on behalf of a permittee, applicant for a permit or person subject to the requirement of a permit shall be sworn to in respect to all statements of fact therein or shall bear an executed statement as provided in Section 210.45 of the New York State Penal Law to the effect that false statements made therein are made under penalty of perjury.

(c) RECORDING OF MONITORING ACTIVITIES AND RESULTS

(1) The permittee shall retain records of all monitoring information, including all calibration and maintenance records and all original strip chart recordings

for continuous monitoring instrumentation, copies of all reports required by a SPDES permit, and records of all data used to complete the application for the permit, for a period of at least 5 years from the date of the sample, measurement, report or application. This period may be extended by written request of the department, provided that the extension is necessary to implement the provisions of this Part or ECL and that the reason or reasons for the extension are provided in the request.

(2) Records of monitoring information shall include:

(i) the date, exact place, and time of sampling or measurements;

(ii) the individual(s) who performed the sampling or measurements;

(iii) the date(s) analyses were performed;

(iv) the individual(s) who performed the analyses;

(v) the analytical techniques or methods used;

(vi) the results of such analyses; and

(vii) Quality assurance/quality control documentation.

(3) When records are stored electronically, the records must be preserved in a manner that reasonably assures their integrity and are acceptable to the department. Such records must also be in a format which is accessible to the department.

(4) The permittee shall make available to the department for inspection and copying or furnish to the department within 25 business days of receipt of a department request for such information, any information retained in accordance with this subdivision.

(d) TEST AND ANALYTICAL PROCEDURES

(1) Monitoring and analysis conducted in accordance with an issued SPDES permit must be conducted using test procedures promulgated pursuant to 40 CFR Part 136 (Test Procedures - see section 750-1.24 of this Part), except:

(i) when the permit specifies an alternative procedure; or

(ii) when the permittee applies to the department and the department approves an alternative test method in accordance with applicable law and regulation.

(2) Any laboratory test or sample analysis required by this permit for which the State Commissioner of Health issues certificates of approval pursuant to section 502 of the Public Health Law shall be conducted by a laboratory that has been issued a certificate of approval.

(3) Application for approval of alternative test procedures shall be made to the department's regional permit administrator, and shall contain:

(i) the name and address of the applicant or the responsible person making the discharge, the DEC permit number and applicable SPDES identification number of the existing or pending permit, name of the permit issuing agency, name and telephone number of applicant's contact person;

(ii) the names of the pollutants or parameters for which an alternate testing procedure is being requested, and the monitoring location (s) at which each testing procedure will be utilized;

(iii) justification for using test procedures, other than those approved in paragraph (a) of this section; and

(iv) a detailed description of the alternate procedure in accordance with requirements set forth 40 CFR Part 136 (see section 750-1.24) or other applicable law and regulation.

(e) REPORTING OF MONITORING RESULTS AND OTHER INFORMATION

(1) The permittee shall submit the results of any wastewater or ambient monitoring results required by the permit at the end of each month, unless otherwise specified by the department. Such reports shall be made on the reporting forms supplied to the permittee by the department, in a format acceptable to the department, or by the electronic transfer of data as approved by the department. Electronic submissions shall conform to the format, standards and other conditions specified by the department. The regional water engineer may also require the submittal of such other information as is necessary to determine the validity of monitoring results submitted in accordance with permit requirements. In no event shall reports on discharges to surface waters required by this subdivision be submitted at a frequency of less than once per year.

(2) For any parameter, analytical results shall be reported to the same number of significant digits as the permit limits or action level for that parameter. If the permit does not clarify the number of significant digits to which results should be reported, the results must be reported to two significant digits, except in cases of effluent TSS or BOD where single digit effluents are achieved. In these cases single digits may be reported.

(3) On each discharge monitoring report, the permittee shall include the ELAP identification number or numbers for the certified laboratory or laboratories who performed the analyses, the results of which are summarized on that Discharge Monitoring Report. Where the monitoring is not performed under ELAP, the permittee shall provide the MDL for the parameter monitored.

(4) If the permittee monitors any pollutant at the discharge or monitoring point or points described in the permit or if the permittee monitors the waters of the

state to which the permittee discharges more frequently than required by the permit and, where the analysis for that monitoring is performed by a certified laboratory or where such analysis is not required to be performed by a certified laboratory, such monitoring results shall be appended to the discharge monitoring report for the period during which the monitoring was performed.

§750-2.6 Special Reporting Requirements for Dischargers that are not POTWs.

(a) All existing dischargers that are not POTWs must notify the Regional Water engineer as soon as they know or have reason to believe that any activity has occurred or will occur that would result in the discharge of any pollutant that is not a "discharge" authorized by a SPDES permit as defined in section 750-1.2 of this Part.

(b) Facility expansion, as defined in section 750-1.2 of this Part, for all existing dischargers that are not POTWs must be reported by submission of a letter to the regional water engineer. The department may determine that additional information must be submitted or that the information submitted by letter to the regional permit administrator must be submitted on a department application form.

The department may determine, on the basis of such information, and any related investigation, inspection or sampling, that a modification of the permit is necessary to assure maintenance of water quality standards or compliance with other provisions of ECL Article 17 or the Clean Water Act. Conversely, the department may determine in accordance with this Part that the proposed activity does not require a permit modification. Unless the department determines that a permit modification is unnecessary, operations that fit the following criteria, which may result in discharges that are not discharges authorized by the SPDES permit, are prohibited until the permit has been modified in accordance with the Part 621 of this Title:

(1) increases in production or the mass of any one pollutant in wastewater that occur and are expected to continue or have occurred and been existing for more than one year; or

(2) the permittee commences a new operation, of which no operations in this category currently exist at the facility, subject to regulation under 40 CFR 405 to 471 and/or 40 CFR Part 125 (see section 750-1.24) which will result in pollutants which the permittee knows or has reason to believe will be discharged (except substances not required to be reported on the appropriate and current New York State SPDES permit application) and which is not described in the SPDES permit application record upon which the current permit is based.

(c) The permittee shall submit written notice to the department if the permitted facility experiences a decrease in production, a decrease of process flow, or a facility modification, where such change results in a greater than 20 percent decrease in the discharges of a pollutant explicitly limited in a SPDES permit and the limit was based on production or flow, provided that such decrease in discharge is expected to continue or has been existing for more than one year.

§750-2.7 Incident Reporting

(n) ANTICIPATED NONCOMPLIANCE. The permittee shall give at least 45 days advance notice to the Regional water engineer of any change in the permitted facility or activity that the permittee knows or has reason to know would occur as part of a construction project, which is part of the permittee's routine maintenance program, or which the permittee knows or has reason to know about 60 or more days before it occurs, and that is very likely or certain to result in a bypass or other noncompliance with permit requirements.

(1) Such notice shall contain:

(i) a description of the treatment units to be effected;

(ii) the anticipated character and volume of wastewater and/or stormwater to be discharged;

(iii) the need for the changes;

(iv) the anticipated duration of the non-compliance;

(v) the receiving stream for the non-complying wastewater and/or stormwater;

(vi) the anticipated benefits of the change;

(vii) the alternatives considered and

(viii) such additional information requested by the Regional water engineer to assess the effects of and need for such a change.

(2) In the time between notification of a planned change and the date scheduled for the change the department may choose to do one or more of the following:

(i) Require additional information that can reasonably be used to decide the necessity of such non-compliance;

(ii) Require that the permittee delay the planned change up to 45 additional days until the department may adequately assess the necessity for the planned change;

(iii) Require the permittee to modify the planned change;

(iv) Prohibit the planned change; or

(v) Apply new conditions to the planned change.

(o) TWO HOUR ORAL REPORTING OF BYPASS, UPSET OR OTHER INCIDENT. For discharges that would affect bathing areas during the bathing season, shellfishing or public drinking water intakes, the permittee shall, within two hours of becoming aware of the discharge, report orally to the regional water engineer and the local health department of any discharge of untreated or partially treated sewage, except a discharge due to a properly operating, wet weather combined sewer overflow or a discharge in accordance with a department approved plan for managing wastewater (provided that such plan is in compliance with applicable law and regulation). Each permittee that must provide oral report within two hours under this subdivision for incidents resulting in discharges from the permittee's site or service area will be so notified in writing by the regional water engineer. Such a report shall include:

(1) A brief description of the bypass, upset, or other incident;

(2) The location of the bypass, upset or other incident including the receiving water effected by the bypass, upset, or other incident;

(3) The estimated volume and characteristics of the discharge at the time of the oral report;

(4) A brief description of the measures taken to end the bypass, upset, or other incident; and

(5) An estimate when the bypass, upset, or other incident will be over and the total expected volume of the discharge.

(e) TWENTY FOUR HOUR ORAL REPORTING OF BYPASS, UPSET OR OTHER INCIDENT. The permittee shall report, including the same information required to be reported under subdivision (d) of this section, orally to the regional water engineer within 24 hours from the time the permittee becomes aware of any of the following incidents:

(1) A discharge of untreated or partially treated sewage that would otherwise be treated, except a discharge due to a properly operating wet weather combined sewer overflow or a discharge in accordance with a department approved plan for managing wastewater and or stormwater (provided that such plan is in compliance with applicable law and regulation);

(2) A discharge of untreated wastewater and or stormwater that would otherwise be treated, except a discharge in accordance with a department approved plan for managing wastewater (provided that such plan is in compliance with applicable law and regulation);

(3) A spill that may result in a discharge that may:

(i) violate permit limitations of pollutants limited in the SPDES permit;

(ii) exceed an action level or more than one action level in the SPDES permit;

(iii) cause discharges of pollutants not explicitly listed in the SPDES permit, in amounts in excess of normal effluent variability of the level of discharge that may reasonably be expected for that pollutant from information provided in the SPDES permit application record; or

(iv) which would result in dilution in lieu of treatment of a discharge authorized by a SPDES Permit.

(4) A spill to waters of the state of greater than the reportable quantity for releases to water as set forth in Part 597 of this Title; or

(5) A bypass, upset or other incident that a reasonable practitioner in water pollution control would consider to be similar in severity and consequences to the incidents set forth in the other paragraphs of this subdivision.

(d) FIVE DAY WRITTEN INCIDENT REPORT. A written report to the Regional water engineer of a bypass, upset or other incident reported under subdivisions (b) and (c) of this subsection shall also be provided within five (5) days of the time the permittee becomes aware of the circumstances. The written report shall contain a description of the bypass, upset, or other incident and its cause; the period of the bypass, upset, or other incident, including exact dates and times, and if the bypass, upset, or other incident has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent the bypass, upset, or other incident and its reoccurrence. The regional water engineer may waive the written report on a case-by-case basis if the oral report has been received within the time periods required under subdivisions (b) and (c) of this subsection.

(e) ADDITIONAL REPORTING. The permittee shall report all instances of noncompliance with permit conditions not otherwise required to be reported under these regulations or the SPDES permit, with each submitted copy of its discharge monitoring reports until such noncompliance ceases. Such noncompliance reports shall contain the same information required to be submitted under subdivision (d) of this section.

(f) DUTY TO MITIGATE. The permittee shall take all reasonable steps to minimize or prevent any discharge in violation of the permit, which has a reasonable likelihood of adversely affecting human health or the environment.

(g) DUTY TO ASSESS. Where a bypass, upset, or other incident occurs as defined in subdivision (b) or subdivision (c) that can reasonably be expected to create detectable discharges of a substance where that substance was not detectable prior to the bypass, upset, or other incident or the bypass, upset, or other incident can reasonably be expected to increase the discharge of a substance or substances by 20 percent or more, the permittee shall collect at least one representative sample for each day of discharge effected by the bypass, upset or other incident in a manner that can be used to assess compliance with the permit. Each sample should be monitored for the parameters which the permittee knows or has reason to believe will be detectable or increased by 20 percent or more in the discharge due to the bypass, upset, or other incident.

§ 750-2.8 Disposal System Operation And Quality Control

(a) GENERAL.

(1) The disposal system shall not receive or be committed to receive wastes beyond its design capacity for volume and character of wastes treated without written approval of the regional water engineer. Nor shall the system operation

be impaired by alterations to the type, degree, or capacity of treatment provided; disposal of treated effluent; or treatment and disposal of separated scum, liquids, solids or combination thereof resulting from the treatment process without written approval of the department or its duly authorized representative.

(2) The permittee shall, at all times, properly operate and maintain all disposal facilities, which are installed or used by the permittee to achieve compliance with the conditions of the permit. Proper operation and maintenance also includes as a minimum, the following:

(i) A preventive/corrective maintenance program for all critical facilities and systems of treatment and control (or related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of the permit. A facility or system is critical if it contains process equipment that is essential for proper operation and necessary to achieve compliance with the applicable SPDES permit effluent limits;

(ii) Written procedures for operation and maintenance, training new operators, adequate laboratory controls and appropriate quality assurance. This provision requires the operation of installed backup or auxiliary facilities or similar systems only when the operation is necessary to achieve compliance with the conditions of the permit.

(3) When required under Part 650 of this Title, sufficient personnel meeting qualifications for operators of sewage treatment works as required therein and additional maintenance personnel shall be employed to satisfactorily operate and maintain the treatment works.

(4) The permittee shall not discharge floating solids or visible foam.

(5) The permittee and operator shall operate the wastewater treatment facility in such a manner as to minimize the discharge of pollutants to a degree that is achievable when compared to standard practices for operation of such wastewater treatment facilities.

(6) The permittee and operator shall operate the wastewater treatment facility in such a manner as to minimize odors and other nuisance conditions to a degree that is achievable when compared to standard practices for operation of such wastewater treatment facilities.

(b) BYPASS

(1) Bypass not exceeding limitations. The permittee may allow any bypass to occur that does not cause effluent limitations to be violated, but only if it also is for essential maintenance, repair or replacement to assure efficient and proper operation. These bypasses are not subject to the paragraph (2) of this subdivision, provided that written notice is submitted prior to the bypass in

accordance with subdivision 2.7(a) of this Part (if anticipated) or (if unanticipated) with the discharge monitoring report for the reporting period during with the bypass occurred. Covered under this paragraph is the diversion of wastewater or stormwater around any portion of a treatment facility in accordance with a department approved plan for wastewater or stormwater management (provided that such plan is in compliance with applicable law and regulation).

(2) Prohibition of bypass. Except as provided for in paragraph (1) of this subdivision, bypass is prohibited, and the department may take enforcement action against a permittee for bypass, unless:

(i) bypass was unavoidable to prevent loss of life, personal injury, public health hazard, environmental degradation or severe property damage;

(ii) there were no feasible alternatives to the bypass such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal period of equipment downtime. This condition is not satisfied if adequate backup equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass that occurred during normal periods of equipment downtime or preventive maintenance or if designed and installed backup equipment that could have prevented or mitigated the impact of the bypass is not operating during the bypass; and

(iii) the permittee submitted notices as required under section 2.7 of this subpart and, excepting emergency conditions, the proposed bypass was accepted by the department.

(c) UPSET.

(1) Effect of an upset. An upset constitutes an affirmative defense to an action brought for noncompliance with such permit effluent limitations if the requirements of paragraph (2) of this subdivision are met. No determination made during administrative review of claims that noncompliance was caused by upset, and before an action for noncompliance, is final administrative action subject to judicial review.

(2) Conditions necessary for a demonstration of upset. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed, contemporaneous operation logs, or other relevant evidence that:

(i) an upset occurred and that the permittee can identify the cause (s) of the upset;

(ii) the permitted facility was, at the time, being properly operated; and

(iii) the permittee submitted notice of the incident for which an upset defense in being claimed as required in section 750-2.7 of this Part.

(iv) the permittee implemented any mitigation and assessment required under section 750-2.7, subdivisions (f) and (g) of this Part.

(3) Burden of proof. In any enforcement proceeding the permittee seeking to establish the occurrence of an upset has the burden of proof.

(d) SPECIAL CONDITION - DISPOSAL SYSTEMS WITH SEPTIC TANKS. Unless otherwise directed by the regional water engineer, if a septic tank is installed as part of the disposal system, it shall be inspected by the permittee or his agent for scum and sludge accumulation at intervals not to exceed one year's duration, and such accumulation will be removed before the depth of either exceeds one-fourth (1/4) of the liquid depth so that no settleable solids or scum will leave in the septic tank effluent. Such accumulation shall be disposed of in accordance with all applicable law and regulation.

(e) RESIDUALS MANAGEMENT . The permittee shall properly store or dispose of collected screenings, sludges, other solids or precipitates removed from the permitted discharges, intakes or supply waters. Proper storage or disposal shall prevent creation of nuisance conditions or the entry of such materials into state waters and shall be in a manner approved by the department. Any live fish, shellfish, or other animals collected or trapped as a result of intake water screening or treatment should be returned to their water body habitat. The permittee shall maintain records of disposal on all effluent screenings, sludges and other solids associated with the discharge(s) herein described. The following data shall be compiled and reported to the department upon request:

(1) the sources of the materials to be disposed of;

(2) the approximate volumes, weights, water content and (if other than sewage sludge) chemical composition;

(3) the method by which they were removed and transported, including the name and permit number of the waste transporter; and

(4) their final disposal locations.

(f) BIOSOLIDS REUSE - Permittees shall make reasonable efforts, to the extent practical, reuse biosolids.

§750-2.9 Additional Conditions Applicable to a Publicly Owned Treatment Works (POTW)

(a) GENERAL

(1) In addition to the requirements set forth in this subpart, all POTWs must provide adequate notice to the department of the following:

(i) As set forth in department guidance on what is a substantial change in volume or character of pollutants introduced into a POTW any such change.

(c) For purposes of this paragraph, adequate notice shall include information on:

(a) the quality and quantity of effluent introduced into the POTW; and

(b) any anticipated impact of the change on the quantity or quality of effluent to be discharged from the POTW.

(2) If the department determines, on the basis of a notice provided pursuant to paragraph (1) of this subdivision and any related investigation, inspection or sampling, that a modification of a permit is necessary to assure maintenance of water quality standards and guidance values or compliance with other provisions of ECL Article 17, this Part, or the Act, then the department may propose such a modification. Unless the department determines that such permit modification is unnecessary, the noticed Act is prohibited until the permit has been modified pursuant to Part 621 of this title.

(3) The permittee shall identify all inflow to the tributary system and remove excessive infiltration inflow to an extent that is economically feasible.

(4) The permittee shall enact, maintain and enforce or cause to be enacted, maintained and enforced up-to-date and effective sewer use law in all parts of the POTW service area. Such enactment and enforcement shall include intermunicipal agreements and/or other enforceable legal instruments that allow the permittee to control discharges, either directly or through jurisdictions contributing flows to the POTW, flow and loads to the POTW as well as discharges to the POTW.

(5) New connections to a publicly owned sewer system or a privatized municipal sewer system are prohibited when the permittee is notified by the department:

(i) that the discharge(s) regulated by a SPDES permit create(s) or is likely to create a public health or potential public health hazard, a contravention of water quality standards or guidance values or the impairment of the best use of waters, as determined by the commissioner; or

(ii) that the permittee has failed or is likely to fail to carry out, meet or comply with any limit or requirement of the permit, compliance schedule, order of the department, federal order, or consent decree.

(6) The provisions provided for in paragraph (5) of this subdivision shall remain in effect until the permittee can demonstrate to the department's

satisfaction and approval that adequate available capacity exists in the plant and that the facility is in full compliance with all of the effluent limitations required by the permit.

(b) NATIONAL PRETREATMENT STANDARDS

(1) All POTWs shall comply with the provisions contained in 40 CFR 403.5(a), (b), (c) and (d) (see 750-1.24 of this Part).

(2) EPA and State Enforcement Actions. If, within 30 days after notice of an interference or pass-through violation has been sent by EPA or the department to the POTW, and to persons or groups who have requested such notice, the POTW fails to commence appropriate enforcement action to correct the violation, EPA and the department may take appropriate enforcement action.

(3) POTWs required by the department to develop a pretreatment program in accordance with 40 CFR 403.8 shall submit an approvable program application in accordance with 40 CFR 403.8 (see section 750-1.24 of this Part).

(4) The approval authority, as defined by 40 CFR 403.3 (see section 750-1.24 of this Part), shall review, require changes to, approve and/or disapprove such a program in accordance with 40 CFR 403.9 and 403.11(see section 750-1.24 of this Part).

(5) POTWs and industrial users shall submit reports as required in accordance with 40 CFR 403.12 (see section 750-1.24 of this Part).

(6) Industrial users may obtain intake credits in accordance with 40 CFR 403.15 (see section 750-1.24 of this Part).

(7) Modifications to pretreatment programs shall be made in accordance with 40 CFR 403.18 (see section 750-1.24 of this Part).

(c) POTW DESIGN, PLANNING AND FLOW MANAGEMENT

(1) Flow Management Plan

(i) Within 120 days of when the permittee determines in accordance with paragraph 4 of this subdivision that the annual average flow value for a calendar year to a POTW has reached or exceeded 95 percent of that POTW's design flow, the permittee shall submit to the regional water engineer a flow management plan to identify and implement reductions in hydraulic loading to the POTW treatment plant or failing that, approvable engineering reports, plans and specifications and/or capital improvements as necessary to stabilize annual average flows below the POTW treatment plant design flow. This plan shall be certified by a professional engineer licensed to practice in the State of New York and endorsed by the chief fiscal officer of the municipality. The provisions of the plan may reflect new efforts or may refer to existing, ongoing efforts. The flow management plan shall, at a minimum, include provisions for:

(a) A statement to the effect that the permittee has the authority in all parts of the POTW service area to implement or cause to be implemented the provisions of this subdivision or, if the permittee does not have such authority, a proposed schedule, not to exceed three years, to obtain such authority or a statement from the permittee's designated legal representative that existing law precludes the permittee from obtaining such authority.

(b) An inventory of all known facilities projects that have applied to connect to the sewer system and a determination if there is capacity for connection.

(c) A schedule of implementation for all flow reduction measures identified herein.

(d) A map delineating the service area as defined; and

(e) A description of information that will be reported during implementation of the plan to the regional water engineer and a schedule for such reporting.

(ii) The flow management plan required by subparagraph (i) of this paragraph shall also include provisions for implementation of any or all of the following that are necessary to stabilize influent flows below design flows:

(a) Water conservation measures to reduce customer usage by measures including but not limited to customer metering, meter calibration, retrofitting existing plumbing fixtures with water conservation fixtures and revision of water rate structures;

(b) Reduction of infiltration and inflow through continuous measures including but not limited to sewer system metering, evaluation and rehabilitation, removal of roof leaders and footing drains from separate sanitary sewers and installation of separate storm sewers;

(c) Prevention of future sources of infiltration and inflow where feasible through measures including but not limited to implementation of standards for sewer installation and requirements to provide for adequate drainage from roof leaders and footing drains in new construction;

(d) Measures to maximize sewer system and sewage treatment works capacity at a minimum cost; and/or

(e) Approvable engineering reports and/or plans and specifications to assure annual average flows do not exceed 95 percent of the POTW treatment plant design flow.

(f) Capital improvements necessary to assure annual average flows do not exceed 95 percent of the POTW treatment plant design flow.

(iii) Within 90 days of submittal to the regional water engineer of the plan required under subparagraphs (i) and (ii) of this paragraph, the permittee shall begin to implement the provisions of said program in accordance with the proposed schedule or cause the provisions of said program to be implemented by another party.

(iv) The regional water engineer may object to the plan, or implementation of the plan, submitted in accordance with subparagraph (i) and (ii) of this paragraph if the plan does not provide for substantive and effective measures to reduce hydraulic loading to the POTW. Within 90 days of receipt of written notification from the regional water engineer documenting the aspects of the plan that must be revised, the permittee shall submit a revised plan that addresses the department's objection(s).

(2) Planning

(i) Within 120 days of when the permittee determines that the actual influent mass loading of Biochemical Oxygen Demand or Total Suspended Solids to a POTW has reached or exceeded the design influent loading for those parameters for any eight calendar months during a calendar year, the permittee shall submit a plan for future growth at the POTW. The plan shall include:

(a) Provisions for obtaining any necessary funding; and

(b) Provisions for preparation and submission to the regional water engineer of approvable engineering reports and/or plans and specifications to provide for growth of discharges in the POTW service area.

(c) A demonstration of the permittee's ability to impose a connection moratorium in any and all parts of the service area or, if the permittee does not have such authority, a proposed schedule, not to exceed three years, to obtain such authority or a statement from the permittee's designated legal representative that existing law precludes the permittee from obtaining such authority.

(iii) The regional water engineer may object to the plan, or implementation of the plan, submitted in accordance with subparagraph (i) of this paragraph if the plan does not provide for substantive and effective measures to accommodate future growth of discharges from the POTW service area. Within 90 days of receipt of written notification from the regional water engineer documenting the aspects of the plan that must be revised, the permittee shall submit an approvable, revised plan that addresses the department's objection(s).

(iv) Within 90 days of submittal to the regional water engineer of the plan required under subparagraph (i) of this paragraph, the permittee shall begin to implement the plan to obtain the authority required under clause (a) of subparagraph (i) of this paragraph.

(3) Plan Implementation and Sewer Connection Moratorium. For POTWs that have exceeded the design influent loading criteria set forth in paragraph (2) of this subdivision, within 90 days of when the permittee determines that, in accordance with the annual review required by paragraph (4) of this subdivision, that the effluent discharge from a publicly owned treatment works has exceeded a SPDES permit limit for Biochemical Oxygen Demand or Ultimate Oxygen Demand for any four or more months during two consecutive calendar quarters, or a SPDES permit limit for Total Suspended Solids for any four or more months during two consecutive calendar quarters , the permittee shall:

(i) Begin to implement the plan developed in accordance with paragraph (2) of this subdivision or in accordance with subparagraph (i) of this paragraph; and

(ii) Cease the further approval of sewer connections to the POTW.

(4) Annual Certification. The chief fiscal officer of any municipality subject to this subdivision shall certify in writing to the department as an attachment to its February discharge monitoring report that the municipality is complying with the provisions of this subdivision and, if applicable, is complying with the implementation schedule in the program adopted in accordance with paragraphs 1, 2 and 3 of this subdivision or if such compliance certification cannot be provided to the department, satisfactory explanation for deviation from the provisions of this subdivision must be provided.

(5) Rescission of Plan Requirements or Moratoria. The regional water engineer may rescind or hold in abeyance any or all of the conditions imposed under this subdivision provided the permittee can demonstrate to the satisfaction of the department that:

(i) The conditions were implemented on the basis of erroneous data; or

(ii) The situation that gave rise to the imposition of the conditions has been adequately addressed; or

(iii) There is an existing or potential public health nuisance or hazard as determined by the state Department of Health, that is best remediated by rescinding or holding in abeyance the conditions; or

(iv) All compliance conditions in a SPDES permit or a judicially or administratively imposed order have been or will be met.

(6) Violations of Permit Limits. Compliance with this section does not, in any way, shield the permittee from enforcement actions for violations of SPDES permit limits.

(7) The regional water engineer may, by written approval, upon adequate demonstration of compelling need, allow for relaxation of schedules contained in this subdivision.

§750-2.10 Special Provisions - New or Modified Disposal Systems or Service Areas

(a) Except as provided in subdivision (h) of this section, prior to construction of any new or modified waste disposal system or modification of a facility or service area generating wastewater that could alter the design volume of, or the method or effect of treatment or disposing of the sewage, industrial waste or other wastes, from an existing disposal system, provided that discharge from such system is required in accordance with this Part to be authorized under a SPDES permit, the permittee shall submit to the regional water engineer an approvable engineering report, plans, and specifications that have been prepared by a person or firm licensed to practice professional engineering in the State of New York in accordance with standards accepted by the department.

(b) The construction of such new or modified disposal system shall not start until the discharger receives written approval of the system from the department and an issued permit. The department may require the discharger to remove any constructed disposal system or portion thereof if such a system or portion thereof is constructed prior to written approval from the department. The department may approve portions of disposal systems to allow for design and construction of disposal systems to proceed at the same time.

(c) The construction of such new or modified disposal system shall be under the general supervision of a person or firm licensed to practice professional engineering in the State of New York. Upon completion of construction, that person or firm shall certify to the department that the disposal system has been fully completed in accordance with the approved engineering report, plans and specifications, permit and letter of approval; and the permittee shall receive written acceptance of such certificate from the department prior to commencing discharge.

(d) The department reviews disposal system reports, plans, and specifications for treatment process capability only, and approval does not represent any opinion of the system's structural integrity.

(e) Department approval of the disposal system or service area does not relieve the permittee of any responsibility for compliance with its SPDES permit.

(f) The department may accept, in lieu of submission of engineering reports or plans and specifications, certification by a person or firm licensed to practice professional engineering in the State of New York that the design of the disposal system or service area conform to design standards accepted by the department. The department may require certification by letter or form (where the form may include but is not limited to a checklist consistent with the applicable standards). Such certifications shall be deemed certifications in accordance with ECL Section 17-0815.

(g) The following standards are accepted by the department:

(1) Ten States Standards (see section 750-1.24) for use in designing POTWs and POTW collection systems;

(2) Intermediate Design Standards (see section 750-1.24) for use in designing facilities that are not POTWs, which treat only sanitary sewage; and

(3) Other standards that are acceptable by the department.

(h) Submission of approvable engineering report, plans, and specifications is not required where:

(1) the treatment unit is temporarily (less than one year) installed for benchmarking and/or troubleshooting and the permittee has provided notification to the Regional water engineer at least 30 days prior to installation;

(2) an equivalent or superior treatment unit is installed;

(3) changes to treatment units do not have a reasonable potential to affect the discharge.

(i) Sewer Extensions, public or private, must be reviewed and approved in accordance with this section before construction and connection to any conveyance tributary to a SPDES permitted discharge.

§750-2.11 Closure Requirements for Disposal Systems

(a) This section applies to any and all disposal systems permanently removed from use or operation at SPDES permitted facilities or at facilities for which a SPDES permit has been revoked or an application for renewal denied, unless a judicial or administrative stay is in effect. The intent of this section is to protect public safety and health and to assure that no contamination of ground or surface water will occur as a result of removing such systems from service either through the act of closure or through continuing the discharge of pollutants into or through equipment, or through leaking, leaching, or discharge of pollutants from wastewater or residuals remaining in disposal systems which has been removed from use but remains on site.

(b) The closure of a disposal system means either the termination of the source of wastewater or stormwater, or the permitted conveyance of wastewater or stormwater to an alternate location (such as a regional facility) in such a manner that no further treatment, storage or conveyance of wastewater or stormwater is performed by the system.

(c) Disposal system closures shall conform with the following procedures:

(1) On or before 60 calendar days prior to taking the system out of service a permittee shall:

(i) Submit to the Regional water engineer the following information concerning closure activities:

(a) The date the system will cease operation;

(b) The date the influent and effluent pipes will be sealed;

(c) Plans (signed and sealed by a New York State licensed professional engineer) for final disposition of the physical facilities, including all treatment units, outfall line, and all mechanical and electrical equipment and piping;

(d) Plans (signed and sealed by a New York State licensed professional engineer) for elimination of all equipment and/or conditions that could possibly pose a safety hazard, either during or after shut-down of operations;

(e) Verification that there are no lines in the collection system which are cross connected (receiving both sanitary and storm water) or which do not contain adequate conveyance capacity;

(f) The name of the licensed individual responsible for the maintenance and operation of the wastewater pumping station and/or disposal system systems that are still to be maintained; and

(ii) Notify the Regional water engineer, in writing, concerning any deactivated lagoons or other actual or potential discharges to ground water which may exist at the site.

(2) Proper management and/or removal of all residual materials (collected grit and screenings, scums, sand bed material, and dried or liquid sludges), as well as filter media, and all other solids from the treatment process that may remain in the abandoned treatment works is required.

(i) The permittee shall submit to the Regional water engineer proof

of ownership of or contractual arrangement with an operation or operations permitted to manage all such waste materials. A contract with a hauler will only be accepted as proof of proper waste management if documentation of management at an approved site or sites is included. In addition, all necessary State or Federal permits approvals must accompany the submission.

(iii) All residual material shall be removed within 180 calendar days after the system is taken out of service. Proof of proper residuals management shall be submitted to the Regional water engineer within 30 calendar days after their removal. The dates of removal and quantities removed shall be specified.

(d) Upon satisfaction of closure requirements specified in (c) above, the Regional water engineer shall be contacted, in writing, to schedule a final site inspection of any disposal system which had a SPDES discharge permit to verify that influent and effluent pipes have been sealed and that all solid and residual materials related to the treatment process have been removed.

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(Special messenger)

New York State Department of Environmental Conservation
Albany, N.Y. 12201

Henry L. Diamond
Commissioner

December 7, 1970

Mr. Harry G. Woodbury
Senior Vice President
Consolidated Edison Company of
New York, Inc.
4 Irving Place
New York, New York 10003

Dear Mr. Woodbury:

Water Quality Certification
Indian Point Generating Station

In response to your letter of September 2, 1970 and in accordance with Section 21-b of the Water Quality Improvement Act of 1970 (P.L. 91-224), reasonable assurance is hereby given by the State of New York that the effluent from Generating Station Units #1 and #2 to be discharged through the submerged jet outlet will not contravene the applicable water quality standards for the Hudson River at the point of discharge. This letter supercedes our letter of September 29, 1970.

Accordingly, an operating permit will be issued upon receipt of the required application under provisions of Part 73, Title 10 of the Official Compilation of Codes, Rules and Regulations of the State of New York. However, prior to the granting of operating permits for the discharge of effluents from Unit 3, the applicant must demonstrate that thermal criteria relating to limits and distribution of temperature and the thermal standard relating to conditions noninjurious to fish life will be satisfied.

Very truly yours,

T. P. Curran
For Department of Environmental
Conservation

cc: Mr. D. Stevens
Mr. I. Grossman
Mr. W. McKeon
Mr. R. Mt. Pleasant
Mr. T. Quinn
Corps of Engineers - New York
Federal Water Quality Administration
U.S. Department of the Interior

STATE OF NEW YORK
DEPARTMENT OF
ENVIRONMENTAL CONSERVATION
ALBANY

OGDEN REID
COMMISSIONER

May 2, 1975

Dear Sirs:

We have reviewed your application of October 4, 1974, for certification pursuant to Section 401 of the Federal Water Pollution Control Act Amendments of 1972, Public Law 92-500 ("the Act"). In the application, Consolidated Edison Company of New York, Inc. (Con Edison) requested certification for its Indian Point Nuclear Power Plant Unit No. 3 (Indian Point No. 3), for the purposes of the U.S. Atomic Energy Commission, now the U.S. Nuclear Regulatory Commission (Commission), license to operate Indian Point No. 3 and the U.S. Environmental Protection Agency permit pursuant to the National Pollutant Discharge Elimination System (NPDES). Indian Point No. 3 is located on the east bank of the Hudson River in the Village of Buchanan, Westchester County, New York, adjacent to two other nuclear power plants, Units No. 1 and 2.

Con Edison or any assignee or successor to the license or permit of Con Edison or any of its obligations hereunder is hereinafter referred to as the "Licensee".

This certification applies to the Commission license to operate Indian Point No. 3 and any appurtenant devices, structures or facilities used in conjunction with Indian Point No. 3, such as, but not limited to, the discharge structure which is common to Indian Point Units No. 1, 2 and 3. This certification also applies to the U.S. Environmental Protection Agency NPDES permit. In view of the changes in operation of the common discharge structure and the recent promulgation of State thermal standards and criteria (6 NYCRR Part 704) this certification is supplemental to the certification dated September 24, 1973 with respect to Indian Point Unit No. 2. To the extent any requirement of this certificate for the Indian Point site is inconsistent with a requirement of the certificate for Indian Point Unit No. 2, the requirements of this certificate shall prevail.

Public notice of the application has been duly given pursuant to Part 608.16 of the official Compilation of Codes, Rules and Regulations of the State of New York.

Based upon the foregoing, the Department of Environmental Conservation (Department) hereby certifies that the Licensee will comply with all applicable provisions of Sections 301, 302, 306 and 307 of the Act, provided that

I. There are no future changes in any of the following that would result in non-compliance with Sections 301, 302, 306 and 307 of the Act:

A. The proposed construction and operation of the facility;
B. The characteristics of the waters into which discharges are made;
C. The water quality criteria applicable to such waters; or
D. Applicable effluent limitations or other requirements;

II. The applicable provisions of State laws and regulations are complied with; and

III. The following effluent limitations and other limitations and monitoring requirements, which shall become conditions on any Commission license and NPDES permit for Indian Point No. 3, pursuant to Section 401(d) of the Act, are complied with:

A. REQUIREMENTS FOR MINIMIZING ENVIRONMENTAL IMPACT

1. In the event that an alternative to the present once-through cooling system is ultimately required pursuant to final Commission action, NPDES permit or other circumstance, a compliance schedule for the construction of such a system shall be established by the State pursuant to the provisions of Article 15, 17 and 19 of the Environmental Conservation Law and the applicable provisions of the Act.

If the Commission does not require such alternative system, or, if as a result of any intermediate or final Commission order, NPDES permit, court decision, settlement or other circumstance there is, in the judgment of the Department, a substantial likelihood that no such alternative system will be required, whichever event may first occur, Licensee shall, within sixty days of the date of

Commission action, NPDES permit or receipt by Licensee of the Department's notice of determination, present to the Department for its approval an implementation plan for the site, including schedules, for compliance with the State's water quality standards and criteria.

2. Within six (6) months of the date of issuance of the Commission operating license, or NPDES permit, whichever shall first occur, Licensee shall prepare and submit to the Department for its approval an implementation plan for minimizing to the extent practicable environmental impacts on aquatic biota from the operation of Indian Point Units 1, 2 and 3 with once-through cooling systems detailing:

a. OPERATING PROCEDURES

This section of the plan shall contain plant procedures relevant to the intake of water and the discharge of effluents.

b. CONTINGENCY PROCEDURES

This section of the plan shall contain the procedures which the plant will follow in order to minimize environmental effects in case of large fish kills and other detrimental effects on aquatic biota. Among other requirements:

(1) The Contingency Procedures shall contain requirements that if the number of fish of all sizes and species collected from the fixed and traveling screens of all forebays at the Indian Point Station exceeds 5,000 per day for three consecutive days or such number in a single day exceeds 15,000, or such other numbers as may be approved by the Department upon application by Licensee, Licensee shall immediately notify the Department by telegram or telephone and shall take immediate corrective action to reduce the number to below these levels. If Licensee fails to reduce such collections to below the levels specified above, Licensee shall immediately notify the Department of its inability to attain such reduction, and the Department may direct Licensee to suspend the operation of the system causing the excess collections; provided, however, no such suspension shall be directed if:

(a) Such suspension would require a power reduction at the facility and Licensee establishes to the reasonable satisfaction of the Department that:

(i) An emergency need for power exists on its system which cannot otherwise be met by consumption reductions or otherwise; or

(ii) Such suspension would create an impact on the indigenous aquatic population of the Hudson River potentially more adverse than such fish kill; or

(iii) Such suspension would cause a significant violation of the appropriate Commission operating license.

(b) The Department believes such suspension would invalidate planned experiments approved by the Department and designed to minimize fish kills.

(2) The Contingency Procedures in the plan shall also contain requirements that if the number of fish of any specified size, species or both collected from the fixed and traveling screens of all forebays at the Indian Point site or otherwise determined to be killed or unduly stressed exceeds such numbers for such lengths of time as may be determined under the biological study program undertaken pursuant to Condition C(7) or otherwise approved by the Department or, if any other specified effect on aquatic biota exceeds such parameters as may be determined under such study program or otherwise approved by the Department, Licensee shall immediately notify the Department and take immediate corrective action to prevent such effect from continuing to occur. If Licensee fails to prevent such effect from continuing to occur, Licensee shall immediately notify the Department of its inability to do so, and the Department may direct Licensee to suspend the operation of the system causing the effect to continue to occur; provided, however, no such suspension shall be directed in the circumstances set forth in Condition A(2)(b)(i)(a) and (b) above.

(3) The plan will include conditions applicable to Indian Point 1, 2 and 3 under which the licensees of Indian Point 1, 2 and 3 will alter the operation of their respective plants and, if necessary, the dispatch of their systems consistent with their obligations for furnishing reliable and economical electric utility service and taking into consideration the national policy for conservation of fuel oil.

(4) The Contingency Procedures shall provide for prompt notification to the Department of shutdowns of all units during the months of December through March which result in significant reduction of the plants' thermal effluent.

c. MODIFICATION TO THE PRESENT DESIGN OF THE ONCE-THROUGH COOLING SYSTEM INCLUDING THE INTAKE STRUCTURES

This section of the plan will explain modifications to intake and discharge structures and other cooling system modifications which the Licensee believes can be made as possible interim solutions to potential biological problems at Indian Point prior to completion of the biological study program, and as possible permanent solutions after the end of that study program.

If it is subsequently determined by a final order of any governmental agency or court that an alternative to the present once-through cooling system is not required for Indian Point Nos. 2 and 3, the Licensee shall design, construct and operate, as provided below, a new intake system for Indian Point Nos. 1, 2 and 3 as required by the Department construction permit dated December 10, 1970 in order to provide a level of fish protection significantly higher than the existing intake system. After obtaining Department approval of the intake system and implementation schedule, Licensee shall forthwith apply for all permits, licenses, approvals and land rights required for the construction and operation of such new intake system and shall prosecute all such applications with due diligence. Upon the granting of all such applications, Licensee shall with due diligence construct and operate said new intake system.

The plans pursuant to a, b and c above shall be designed to reduce to the extent practicable fish impingement, entrainment mortality, and detrimental effects on aquatic biota in the Hudson River from the Indian Point plants during the period during which Indian Point No. 3 utilizes a once-through cooling system. Upon approval by the Department, Licensee shall implement this program in accordance with an approved schedule.

3. Prior to operation of any alternative to the present once-through system, Licensee shall submit to the Department for its approval a plan to minimize to the extent practicable the environmental effects of such alternative cooling system.

4. Within three (3) months of the date of issuance of the Commission operating license, or NPDES permit, whichever shall occur first, the Licensee shall file for approval with the Department at its offices in New Paltz and in Albany a plan on chlorine use and chlorination practice. Such plan shall include practices which minimize the impact of chlorine on water resources.

a. After the Department approves the plan and so long as the once-through cooling system is used, there shall be no use of chlorine which results in a discharge except at times and in circumstances in accordance with the approved report as necessary for the proper functioning of the plants at Indian Point.

b. The maximum concentrations of the total residual chlorine in the cooling water discharged at the confluence of the discharge canal with the Hudson River shall not exceed 0.5 ppm.

B. <u>DISCHARGE LIMITS AND MONITORING</u>

1. The New York State Standards (NYCRR Parts 700, 701, 702, 704) as applicable to the receiving waters shall be complied with including the following:

a. <u>Oil and floating substances</u> - No residue attributable to sewage, industrial waters or other wastes nor visible oil film nor globules of grease.

b. <u>Toxic wastes and deleterious substances</u> - None in amounts that will interfere with use for primary contact recreation or that will be injurious to edible fish or shellfish or the culture or propagation thereof, or which in any manner shall adversely affect the flavor, color, odor or sanitary condition thereof or impair the waters for any other best usage as determined for the specific waters which are assigned to this class.

c. <u>Thermal Discharges</u> -

(1) All thermal discharges to the waters of the State shall assure the protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife in and on the body of water.

(2) For the protection of the aquatic biota from severe temperature changes, routine shutdown of an entire thermal discharge at any site shall not be scheduled during the period from December through March.

(3) All mixing zones shall have definable numerical limits specified by the Department (e.g., linear distances from the point of discharge, surface area involvement, or volume of receiving water entrained in the thermal plume).

(4) Conditions in the mixing zone shall not be lethal in contravention of water quality standards to aquatic biota which may enter the zone.

(5) The location of mixing zones for thermal discharges shall not interfere with spawning areas, nursery areas and fish migration routes.

(6) The location, design, construction and capacity of cooling water intake structures, in connection with point source thermal discharges, shall reflect the best technology available for minimizing adverse environmental impact.

d. <u>Suspended, colloidal or settleable solids</u> - None from sewage, industrial wastes or other wastes which will cause deposition or be deleterious for any best usage determined for the specific waters which are assigned to each class.

e. <u>Estuaries or portions of estuaries</u> - As used herein, estuary shall refer to the Hudson River in the vicinity of Indian Point.

(1) The water temperature at the surface of an estuary shall not be raised to more than 90°F at any point.

(2) At least 50 percent of the cross sectional area and/or volume of the flow of the estuary including a minimum of one-third of the surface as measured from water edge to water edge at any stage of tide, shall not be raised to more than 4 Fahrenheit degrees over the temperature that existed before the addition of heat of artificial origin or a maximum of 83°F whichever is less.

(3) From July through September, if the water temperature at the surface of an estuary before the addition of heat of artificial origin is more than 83°F an increase in temperature not to exceed 1.5 Fahrenheit degrees at any point of the estuarine passageway as delineated above, may be permitted.

2. Licensee shall continue to conduct a continuous chemical, physical, hydraulic, biological, meteorological, and thermal monitoring program in accordance with the ETSR which will be incorporated by the Commission in the applicable operating license and will transmit to the Department concurrently with the reports to the Commission such reports as are required by the ETSR.

This monitoring shall be carried on under the surveillance of the Department and is further understood that such monitoring is in no way intended to supersede the independent monitoring program of the Department, but to supplement it.

3. Licensee shall monitor chemical discharges according to the frequency established in the table below. Analyses shall be performed in accordance with appropriate standard methods and shall be reported monthly as mg/1 and pH units (nearest tenth).

ITEMS	FREQUENCY
pH	DD
Chromium +6 (and +3)**	WK
Boron	D
Phosphate	WK
Hydrazine	MO
Cyclohexylumine	MO
Lithium Hydroxide*	D
Chlorine	I
Suspended Solids	WK
Dissolved Oxygen ***	MO

DD - Continuous at discharge of Neutralization Facility
D - Daily during discharge
WK - Weekly
MO - Monthly
I - At start and at 10 minute intervals during chlorination.

* By pH measurement.

** If total chromium tests show detectable chromium concentrations, a test for trivalent chromium will also be conducted.

*** Dissolved oxygen in ppm shall be measured monthly at the intake forebay and in the effluent canal prior to discharge.

A limitation of 0.05 mg/1 each of trivalent and hexavalent chromium shall apply at the discharge.

A discharge limitation of 100 lbs. chromium per year shall also apply.

A limitation of 0.1 mg/1 Boron shall apply at the outlets of the discharge canal.

4. Dissolved Oxygen - In addition to the requirements above, dissolved oxygen in ppm shall be measured at the intake forebay and in the effluent canal prior to discharge for five (5) days during the week of each routine thermal survey and reported within ninety (90) days of the close of each survey.

5. Discharge shall occur only through the subsurface ports of the outfall structure for which a construction permit has heretofore been issued by the Department. After the date of issuance of the operating license, under all conditions, modes, and sequences of operation of Units 1, 2 and 3 above a combined power level from any and all units of 600 MW gross electric output or whenever the discharge canal temperature exceeds 90°F, Licensee shall maintain an average discharge velocity of not less than ten ft/sec. at the vena contracta of the discharge ports. The relationships between discharge velocity, open port area, and canal head above river level shall be confirmed by actual measurement and reported to the Department. The manual adjustments in the ports shall be made within 12 hours after any change in the flow rate of the circulating water pumps has occurred. After June 1, 1975, the adjustments shall be made within four hours.

C. STUDIES AND BIOLOGICAL DATA

1. Licensee shall study the relationship between the salt water front passing the intakes at Indian Point and the number and kinds of fish impinged. A report presenting this information and data shall be submitted to the Department by September 1, 1975, and if the Department deems it necessary Licensee shall implement an approved program to reduce fish impingement occasioned by salt water passage.

2. Impingement and Entrainment Data and Reports.

a. Within three (3) months of the date of issuance of the operating license, or NPDES permit, whichever is earlier, Licensee shall file for approval with the Department a report containing a tabulation of all fish impingement data collected to date at Indian Point.

b. Within five (5) months of the date of issuance of the operating license, or NPDES permit, whichever is earlier, Licensee shall file for approval with the Department a report containing a tabulation of all entrainment data collected to date at Indian Point.

c. Fish impingement data will be collected, recorded and reported as described in the ETSR.

Also, once a week (or sooner as required by the Contingency Procedure 2.b.(1)), impingement records will be reported to the New Paltz office by telephone or telegram.

Previously submitted reports need not be duplicated, but data location must be completely identified. Reported data shall specify cooling water flow, dates, times, available operating conditions, species, numbers and other available biological information.

3. Upon issuance of the operating license, or NPDES permit, whichever is earlier, the Licensee shall continue the previously initiated site program, or Department approved amendments thereto, for monthly triaxial isothermal measurements for the Indian Point plume. The program shall provide for temperature measurements in increments of 1°F down to a level of 2°F temperature excess above addition of heat of artificial origin. Surveys shall not be required during the months of December, January, February and March. A summary report shall be submitted within 90 days of completing each survey. The program shall continue through November 1977.

4. Within two (2) months of the date of issuance of the operating license, or NPDES permit, whichever is earlier, Licensee shall file for approval with the Department a report for intensive seasonal triaxial isothermal measurements which shall be conducted during April, August and October in the waters receiving the discharge. The program shall provide for temperature measurements in increments of 1°F down to a level of 1°F temperature in excess of the temperature which existed prior to the addition of heat of artificial origin. The data and following analyses for all previous surveys shall be presented at the time of the first required report. Such surveys shall not be required during the year 1975.

Beginning February 1, 1977, for the 1976 surveys, and each February 1st thereafter, Licensee shall file with the Department a complete report on the previous year's intensive isothermal surveys. Such report shall include:

a. A summary and assessment of the data presented for the individual surveys including a complete evaluation of the observed data in respect to the predictive mathematical and hydraulic models, and the assumptions used for their construction, as have been previously filed with the Department.

b. Meteorological conditions, hydrological conditions, heat transfer coefficients, dispersion coefficients, salinity, tidal data and any other appropriate data deemed necessary by the Department to supplement and assist interpretation of the thermal plume mapping program.

c. Data correlated and integrated to the predictive models previously presented to the Department with full justification made for adjustments in previous assumptions and predictions.

d. A revision of expected temperature distributions as appropriate and justified from the data gathered.

e. Background ambient temperature which would persist but for the addition of heat of artificial origin from any and all discharges which would affect the survey area, incremental effects from the operation of the Indian Point plants, and incremental effects of thermal discharges of others that may have influence in the area of the Indian Point discharge.

As there is only one combined discharge from the Indian Point site, for Units Nos. 1, 2 and 3, the triaxial isothermal measurement programs relate to all three units. The intensive program will be suspended if, and when (a) the Licensee shall provide clear and convincing proof, to the satisfaction of the Department that it will comply with all provisions of water quality standards and criteria applicable at the site under any and all conditions of operation of Indian Point Units 1, 2 and 3 or any combination of units, or (b) the Licensee shall initiate construction of an alternative to the present once-through cooling system (provided, however, such program shall be reinstituted if such system is not completed and operated), whichever circumstance, (a) or (b), should first occur.

5. Within three (3) months of the date of issuance of the Commission operating license, or NPDES permit, whichever is earlier, Licensee shall file for approval with the Department a report on all water treatment, corrosion inhibitor, anti-fouling, slimicide, biocide and boiler cleaning chemicals or compounds used in Indian Point Units No. 1, 2 or 3. Such report shall identify each product by chemical formula and/or composition, annual consumption, frequency of use, maximum use per incident, effluent concentration, available bioassay and toxicity limits and procedures for use. Approval shall only be granted for uses which do not contravene New York State Water Quality Standards. Except for emergency measures which shall be reported to the Department within twenty-four hours, no substitutions will be allowed without prior written approval of the Department. As determined by the Department, wastewaters containing chemicals and/or oil shall be collected and treated prior to dilution with non-contact cooling water on a schedule to meet effluent limitations and in facilities which shall be approved by the Department provided that Licensee shall have sixty days from the date of receipt of the Department's determination to present for consideration alternative facilities, controls and measures.

6. Within three (3) months of the date of issuance of the Commission operating license, or NPDES permit, whichever is earlier, the Licensee shall file for approval with the Department a report on practices which minimize the impact and use of chlorine on water resources and identify reports previously submitted to the Department.

7. Within four (4) months of the date of issuance of the operating license, or NPDES permit, whichever is earlier, Licensee shall file for approval with the Department the detailed biological study program it is conducting to determine effects of once-through cooling system operation on aquatic organisms. The Department and Licensee shall from time to time consult on any necessary changes to the program. Segments of such biological study program shall be implemented as approved by the Department. A summary progress report shall be submitted six (6) months following

implementation of the first segment and every six (6) months thereafter. An annual report shall be submitted by July 31 of each year covering the preceding calendar year's operation. Additional reporting requirements may be imposed for certain segments of the program as necessary.

D. SUBMISSION OF ADDITIONAL REPORTS.

1. Starting one month from the date of issuance of the operating license, or NPDES permit, whichever is earlier, Licensee shall submit to the Department a monthly report of daily operating data by the 15th of the following month for:

a. Daily minimum, maximum and average station electrical output in kilowatts which shall be monitored and recorded, and daily minimum, maximum and average electrical output in kilowatt hours, which shall be determined and recorded.

b. Daily minimum, maximum and average water use for each pump, which shall be directly or indirectly measured or calculated and logged. The basis for such measurements or calculation shall be reported.

c. Temperature in degrees Fahrenheit of the intake forebay and effluent canal prior to discharge, which shall be measured and recorded continuously. Daily minimum, maximum, and average intake and discharge temperatures, which shall be logged.

d. Daily fish collections by number, size, weight, and species of fish and other aquatic biota impinged as a result of operation of all units.

2. Licensee shall file with the Department at its offices in New Paltz and in Albany, concurrently with filing with the U.S. Environmental Protection Agency, copies of all applications, reports, and supporting data filed pursuant to Sections 316(a) and 316(b) of the Act.

3. Copies of any other reports for Indian Point Unit No. 3 pertaining to the environment which Licensee submits to any federal, state or local agency, shall also be concurrently submitted to the Department.

4. Licensee shall notify the Department within one week from the time of submission to the Commission of any requested change in the ETSR at the time of such request. Such notification shall fully discuss the requested change.

5. All reports and notifications Licensee provides to the Department pursuant to this certification shall be submitted to the Director of Environmental Analysis in Albany and the Regional Supervisor of Environmental Analysis in New Paltz.

E. OTHER

1. Licensee shall provide access to the Indian Point site at any time to representatives of the Department, subject to site security regulations, to assess the environmental impacts of the operations of Indian Point Units No. 1, 2 and 3 and to review the data gathering techniques of Licensee.

2. Should any limitation or condition of this certification or any permit issued require construction in or on waters of the State or the banks or bed thereof, such construction and associated excavation, fill or disturbance shall require prior approval of the Department under stream protection regulations.

3. This certification with conditions shall not be deemed to modify, extend, or affect in any manner any order of the Commissioner against Licensee; nor does it constitute a condonation of any violation of any order or release, compromise, or waiver of any rights or any course of action which the Commissioner has or may have against Licensee because of any violation of any order and does not preclude compliance of the discharge from Indian Point Units Nos. 1, 2 or 3 with any permit with respect to such discharge which may be hereafter issued by the Commissioner.

This certification with conditions is issued on the basis that the Licensee has not yet established that Indian Point No. 3 as presently designed will meet the State's water quality criteria and standards, and with the full understanding and acknowledgement by licensee that the Department, in cooperation with the U.S. Environmental Protection Agency, has promulgated revised thermal criteria in order to bring such criteria into conformity with the Act.

The acceptance by Licensee of this certification with conditions shall not be deemed a waiver by Licensee of its right to obtain judicial review of any disapproval of a plan, report or other document submitted by Licensee to the Department for its approval, as provided by law.

This certification with conditions is issued solely for the purpose of Section 401 of the Act.

If any condition of this certification is declared invalid, the Department shall reconsider the entire certification and may make appropriate amendments or modifications as a result of such reconsiderations.

A copy of this certification with conditions is being forwarded to the Director of Regulations, U.S. Nuclear Regulatory Commission, and the Regional Administrator of the Environmental Protection Agency.

Sincerely yours,

Consolidated Edison Company
of New York
4 Irving Place
New York, New York 10003

Attention: Mr. Carl L. Newman
Vice President

cc: Nuclear Regulatory Commission
Environmental Protection Agency, Region II

Attachment D

Coastal Management Program Consistency Determination

TO BE SUBMITTED AT LATER DATE

Federal Consistency Certification for Federal Permit and License Applicants[1]

This is the Entergy Nuclear Indian Point 2, LLC (IP2) and Entergy Nuclear Indian Point 3, LLC (IP3), here-in-after referred to as “Entergy”, certification to the U.S. Nuclear Regulatory Commission (NRC) that the renewal of the IP2 and IP3 Operating Licenses will be consistent with enforceable policies of the federally approved state coastal zone management program. The certification describes background requirements, the proposed action (i.e. license renewal), anticipated environmental impacts, New York State Coastal Management Program (NYSCMP) policies, IP2 and IP3 compliance status, and summary findings.

CONSISTENCY CERTIFICATION

Entergy certifies to the NRC that renewal of the IP2 and IP3 Operating Licenses comply with the enforceable policies of New York State’s approved Coastal Management Program (NYSCMP) and will be conducted in a manner consistent with such program. Entergy expects IP2 and IP3 operations during the renewed license terms to be a continuation of current operations as described below, with no physical or operational station alterations that would affect New York State’s coastal zone.

NECESSARY DATA and INFORMATION

Statutory Background

The Federal Coastal Zone Management Act (CZMA) (16 USC 1451 et seq.) imposes requirements on an applicant for a Federal license to conduct a review of an activity that could affect a state’s coastal zone. The Act requires an applicant to certify to the licensing agency that the proposed action would be consistent with the state’s federally approved coastal zone management program. The Act also requires the applicant to provide to the state a copy of the certification statement and requires the state, at the earliest practicable time, to notify the federal agency and the applicant whether the state concurs with, or objects to, the consistency certification. See 16 USC 1456(c)(3)(A).

The National Oceanic and Atmospheric Administration (NOAA) has promulgated implementing regulations that indicate the certification requirement is applicable to renewal of federal licenses for activities not previously reviewed by the state [15 CFR 930.51(b)(1)]. NOAA approved the New York coastal zone management program in 1982. In New York, the approved program is the NYSCMP, and the New York State Waterfront Revitalization of Coastal Areas and Inland Waterways Act, contained in State Executive Law (SEL) Article 42, Department of State regulations in 19 NYCRR Part 600, and State Environmental Quality Review Act (SEQRA) regulations in 6 NYCRR Part 617.

Article 42 SEL 912.9 assures the consistency of federal actions with policies of the New York coastal area and inland waterways and with accepted waterfront revitalization programs of the area. NRC licensing is a federal activity, and the IP2 and IP3 location is within the New York coastal area and inland waterways. IP2 and IP3’s withdrawal from and discharge to coastal areas and inland waterways could reasonably be expected to potentially affect the coastal areas and inland waterways. The state regulation requires certification of compliance with the

[1] This certification is patterned after the example certification included as Appendix E of NRC LIC-203, 2004.

NYSCMP policies (19 NYCRR Part 600.3) and the regulation lists the policies (19 NYCRR Part 600.5). Table D-1 identifies the policies and Entergy's justification for certifying compliance.

Proposed Action

Entergy is applying to the NRC for renewal of the IP2 and IP3 Operating Licenses for an additional 20 years beyond the current expiration dates of September 28, 2013 and December 12, 2015, respectively. Entergy expects IP2 and IP3 operations during the license renewal term to be a continuation of current operations as described in the following paragraphs, with no physical or operational changes that would affect the New York State coastal zone. Entergy certifies that the license renewal application complies with the enforceable policies of the NYSCMP and that IP2 and IP3 will continue to be operated in a manner consistent with such policies.

Background Information

IP2 and IP3 are located 24 miles north of New York City on approximately 239 acres of land on the east bank of the Hudson River in upper Westchester County, New York. There are three reactors at the site, Indian Point Units 1, 2, and 3. IP1 was permanently shut down in 1974 and is in SAFSTOR until it is decommissioned. A decommissioning plan for IP1 has been submitted to the NRC and accepted, with plans for decommissioning when IP2 is decommissioned.

Power generation during the license renewal term will consist of IP2 and IP3, with pressurized water reactors and turbine generators licensed for outputs of 3,216 and 3,216 megawatts-thermal (MWt), and electric ratings of 1078 and 1080 megawatts-electric (MWe), respectively. The IP2 Operating License was issued in September 1973 and expires in September 2013. The IP3 Operating License was issued in December 1975 and expires in December 2015. Entergy Nuclear Operations, Inc., a subsidiary of Entergy, operates the facility. The site exclusion area is shown in Figure 2-3 of the license renewal Environmental Report (ER). Approximately 90% of the area within 6 miles of the station is residential housing, parks, and military reservations. The transmission system that ties IP2 and IP3 to the New York grid is in a single right-of-way to Buchanan Substation, located approximately 2,100 feet southeast of the reactors. In areas such as the Hudson River Valley, the inland boundary of the coastal zone may extend inland up to 10,000 feet. In the vicinity of IP2 and IP3, the boundary lies along Washington Street to the east of the Village of Buchanan, and therefore, the area of interest includes the plant property and the Buchanan Substation [NOAA]. Figures 2-1 and 2-2 of the Environmental Report are IP2 and IP3 50-mile and 6-mile vicinity maps, respectively.

IP2 and IP3 are equipped with once-through heat dissipation systems that withdraw cooling water from and discharge to the Hudson River. The details of the plants' cooling systems, intake structures, and discharge system are provided in Chapter 3 of the license renewal ER. IP2 and IP3 each have shoreline-situated intake structures consisting of seven bays (six for circulating water and one for service water). Ristroph screens and fish return systems were timely installed at IP3 and IP2 and completed in 1990 and 1991, respectively. Design features incorporated into the machines were developed and tested in concert with the Hudson River Fishermen's Association [CHGEC]. Modified baskets employing bucket features collect and lift fish to be returned to the river. Additionally, the head section of the screen employs five (5) spray wash headers; three (3) low pressure fish sprays, and two (2) high pressure debris sprays for debris removal. Each screen well is provided with the ability to install stop logs to allow dewatering of any individual screen well for maintenance purposes. The water from each individual screenwell flows to a motor-driven, vertical, mixed flow condenser circulating water pump. [IP2 UFSAR, Section 10.2.4; IP3 UFSAR, Section 10.2.4]

Fish are returned to the estuary through a 12-inch diameter pipe that extends 200 feet into the river on the north side of the IP2 intake structure. The pipe is partially buried in the river bottom, and discharges fish at a depth of 35 feet. The location of the discharge was selected after conducting dye and fish release studies to find a location that would minimize re-impingement. [CHGEC, Section IV.B.2.c] Key components of the IP3 screens are identical to those installed at IP2. The IP3 fish return system discharges outside the northwest corner of the station's cooling water discharge canal. [CHGEC, Section V.B.2.c.ii]

For IP2, each of the six dual-speed condenser circulating water pumps provides 140,000 gpm and 21-ft total dynamic head when operating at 254 rpm and 84,000 gpm and 15-ft total dynamic head when operating at 187 rpm. Each pump is located in an individual pump well, thus tying a section of the condenser to an individual pump [IP2 UFSAR, Section 10.2.4]. For IP3, each of the six variable-speed condenser circulating water pumps provides 140,000 gpm at 29 ft total dynamic head when operating at 360 rpm [IP3 UFSAR, Section 10.2.4].

The owners use best reasonable efforts to operate the IP2 and IP3 dual and variable speed circulating pumps to keep the volume of river water drawn into the stations during the relevant entrainment period at the minimum required for efficient operation, considering ambient river water temperature, plant operating status, the need to meet water quality standards and other permit conditions. Flow rates are dependent upon intake water temperature and typically peak between early May and late October. In addition, outages are scheduled, where reasonably practicable, in a manner sensitive to entrainment considerations, typically during the late spring entrainment period, with the result that only one unit is operating during that outage period each year. Further, extensive entrainment survival studies reflect a very high level of entrainment survival among certain species.

After moving through the condensers, cooling water from IP2 and IP3 flows downward from the discharge water boxes by way of six 96-inch down pipes, and exits under the water surface in a 40-foot-wide discharge canal.

The outfall or discharge structure for the IP2 and IP3 facility is designed to enhance mixing of cooling water and river water in such a way as to minimize thermal impact in the river. It can accommodate the combined cooling water flow from both IP2 and IP3 (about 1.75 million gpm, including service water). The cooling water from the discharge channel is released to the Hudson River via an outfall structure located south of IP3. The outfall structure consists of 12 submerged rectangular ports equipped with adjustable gates that are in line and parallel to the river axis. The ports, 4 feet high by 15 feet wide and spaced 21 feet apart (center to center), are submerged to a depth of 12 feet (center to surface) at minimum level water. The first upstream port is approximately 600 ft from the IP3 intake; the length of the total port section is approximately 252 feet. The discharge port gates can be adjusted mechanically to maintain a minimum hydraulic head differential of 1.75 feet across the outfall structure, which assures a discharge velocity of approximately 10 fps. [CHGEC, Section IV.B.2.e]

Entergy holds State Pollutant Discharge Elimination System (SPDES) permits for this and other plant/stormwater discharges (NY-0004472, NY-0234826, NY-0250414, NY-0251135) with effluent limitations, monitoring requirements, and other conditions that ensure that all discharges are in compliance with Title 8 of Article 17 of the Environmental Conservation Law (ECL) of New York State and the Clean Water Act (CWA), as amended (33 USC Section 1251 et seq.). In accordance with permit requirements, Entergy monitors discharge characteristics and reports the results to the New York State Department of Environmental Conservation (NYSDEC). Concentrations of radioactivity in effluents are subject to the requirements and limitations of the NRC.

Typically, the temperature increase across the IP3 condenser at 360 RPM is in the range from 14.6°F to 18.0°F (8.1°C to 10°C) and at IP2 with all fast speed pumps from 17°F to 22°F (9.44°C to 12.22°C). Severe fouling due to debris in the Hudson River may cause the water temperature increase across the condensers to go as high as approximately 35°F (19.44°C). The permitted daily average discharge temperature is not to exceed 35°F (34°C) between April 15th and June 30th for more than 15 days a year during that time period, and at no time is the maximum discharge temperature to exceed 110°F (43.3°C).

IP2 and IP3 do not have an onsite wastewater treatment plant. Sanitary wastewaters from all plant locations is transferred to the Village of Buchanan publicly owned treatment works (POTW) system where it is managed appropriately, except for a few isolated areas which have their own septic tanks which are pumped out by a septic company, as needed, and taken to an offsite facility for appropriate management. Although sanitary wastewaters at the site are nonradioactive, a radiation monitoring system is provided to continuously monitor radiation levels in the effluent from the protected area.

As of June 2006, Entergy employs a permanent workforce of approximately 1,255 employees (including baseline permanent contractors) at IP2 and IP3. The majority of the IP2 and IP3 workforce (approximately 78%) lives in Dutchess, Orange, and Westchester Counties. IP2 and IP3 are on a 24-month alternating refueling cycle. During refueling outages, site employment increases above the 1,255 person permanent workforce by approximately 950 workers for temporary duty (approximately 30 days).

Environmental Impacts

The NRC has prepared a Generic Environmental Impact Statement assessing impacts that nuclear power plant license renewal could have on the environment and has codified its findings in 10 CFR 51, Subpart A, Appendix B, Table B-1 [NRC 1996]. The codification identified 92 potential environmental issues, 69 of which the NRC identified as having small impacts and termed “Category 1 issues.” The NRC defines “small” as:

> Small – For the issue, environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purpose of assessing radiological impacts, the Commission has concluded that those impacts that do not exceed permissible levels in the Commission’s regulations are considered small as the term is used in this table (10 CFR 51, Subpart A, Appendix B, Table B-1).

The NRC based its assessment of license renewal impacts on its evaluations of impacts from current plant operations. The NRC codification and the Generic Environmental Impact Statement discuss the following types of Category 1 environmental issues:

- Surface water quality, hydrology, and use
- Aquatic ecology
- Groundwater use and quality
- Terrestrial resources
- Air quality
- Land use
- Human health
- Postulated accidents
- Socioeconomics
- Uranium fuel cycle and waste management
- Decommissioning

In its decision making for plant-specific license renewal applications, absent new and significant information to the contrary, the NRC relies on its codified findings, as amplified by supporting information in the Generic Environmental Impact Statement, for assessment of environmental impacts from Category 1 issues [10 CFR 51.95(c)(4)]. For plants such as IP2 and IP3 that are located in the coastal zone, many of these issues involve potential impacts to the coastal zone. Entergy has adopted by reference the NRC findings and Generic Environmental Impact Statement analyses for all 43[2] Category 1 issues applicable to IP2 and IP3.

The NRC regulation identified 21 issues as "Category 2," for which license renewal applicants must submit additional site-specific information.[3] Of these, 11 apply to IP2 and IP3[4], and like the Category 1 issues, could potentially involve impacts to the coastal zone. The applicable issues and Entergy's impact conclusions are listed below.

- Aquatic ecology
    - ♦ <u>Entrainment of fish and shellfish in early life stages</u> – This issue addresses mortality of organisms small enough to pass through the plant's circulating cooling water system. IP2 and IP3 utilize a once-through cooling water system that withdraws

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2 The remaining Category 1 issues do not apply to IP2 and IP3 either because they are associated with design or operational features that IP2 and IP3 does not have (e.g., cooling towers) or to refurbishment activities, that IP2 and IP3 will not undertake.

3 10 CFR 51, Subpart A, Appendix B, Table B-1 also identifies 2 issues as "NA" for which the NRC could not come to a conclusion regarding categorization. Entergy believes that these issues, chronic effects of electromagnetic fields and environmental justice, do not affect "coastal zone" as that phrase is defined by the Coastal Zone Management Act [16 USC 1453(1)].

4 The remaining Category 2 issues do not apply to IP2 and IP3 either because they are associated with design or operational features that IP2 and IP3 does not have (e.g., cooling towers) or to refurbishment activities that IP2 and IP3 will not undertake.

cooling water from the Hudson River. The plant holds a State Pollutant Discharge Elimination System (SPDES) permit (NY-0004472) for discharge of cooling waters from the New York State Department of Environmental Conservation [NYSDEC 1987]. More than 30 years of extensive fisheries studies of the Hudson River have been conducted in the vicinity of IP2 and IP3. The results of studies performed from 1974 to the present period have not shown any negative trend in overall aquatic river species populations attributable to plant operations [CHGEC; ASA]. The ongoing studies continue to support these conclusions [ASA]. Entergy uses best reasonable efforts to operate IP2 and IP3 dual and variable speed circulating pumps to keep the volume of river water drawn into the stations during the relevant entrainment period at the minimum required for efficient operation, considering ambient river water temperature, plant operating status, the need to meet water quality standards, and other permit conditions. Flow rates are dependent upon intake water temperature, and typically peak between early May and late October. In addition, outages are scheduled, where reasonably practicable, in a manner sensitive to entrainment considerations, typically during the late spring entrainment period, with the result that only one Station is operating during that outage period each year. Further, extensive entrainment survival studies reflect a very high level of entrainment survival among certain species. Mitigation measures implemented through the Hudson River Settlement Agreement and retained in the four Consent Orders, current agreements with NYSDEC, along with the outcome of current draft SPDES Permit proceedings, will ensure that entrainment impacts remain SMALL during the license renewal term [HRSA; NYSDEC 1997].

♦ Impingement of fish and shellfish – This issue addresses mortality of organisms large enough to be caught by intake screens before passing through the plant's circulating cooling water system. The plant has installed Ristroph screens and fish return systems on the IP2 and IP3 intake structures to minimize the impact of impingement. Extensive descriptions of more than 23 years of Hudson River fisheries and habitat studies involving trends in key species abundance, diversity, richness, and mortality rates, and impacts from entrainment and impingement at once-through cooling water intakes were provided in a 1999 Draft Environmental Impact Statement (DEIS) submitted on behalf of the owners of the Roseton, Bowline Point, and Indian Point generating stations [CHGEC]. As mentioned above, continuing studies are ongoing, and are submitted annually to the NYSDEC. The DEIS describes sampling study results at Indian Point (IP2 and IP3), and identified 88 species of fish in more than 20 years of impingement studies. Conditional mortality rate (CMR) estimates of the numbers of fish lost to impingement integrated with estimates of the abundance of fish in the river were presented in the DEIS (as a percentage) to estimate the proportional reduction of the population [CHGEC, Section VI.B.1.b]. CMRs and discussion of models to define the CMRs are presented in the DEIS and its appendixes [CHGEC, Section VI.2.A and B]. The estimated average annual CMR due to impingement for American shad is 0.0%, for Atlantic tomcod is 0.62%, for bay anchovy is 0.05%, for blueback herring is 0.22%, for alewife is 0.14%, for spottail shiner is 0.10%, for striped bass is 0.20%, and for white perch is 1.70% [CHGEC, Section V.D]. It should be noted that the impingement percentages included data collected from 1981 to 1990, which was prior to installation of the Ristroph screens on the IP2 and IP3 intakes. Therefore, the impingement mortality during current operations and the license renewal period would be significantly less, based on the impingement mortality percentage estimates cited above and anticipating the continued use of the Ristroph screens and fish return systems installed. In the Fact Sheet to the draft permit, NYSDEC noted that the current design, along with seasonable flow reductions and generation outages…, attains an estimated 77% reduction in impingement mortality [NYSDEC 2003]. Currently, more than 30 years of extensive fisheries studies of the Hudson River have been completed in the vicinity of IP2 and IP3. The results of the studies performed from 1974 to 1997, the period of time covered in the DEIS, are referenced and summarized in the DEIS, and have not shown any negative trend in overall aquatic river species populations attributable to plant operations. Ongoing studies continue to support these conclusions [ASA]. In addition, current mitigation measures implemented through the HRSA and retained in the four Consent Orders, the current agreements with NYSDEC, along with the outcome of the draft SPDES Permit proceeding, will ensure that impingement impacts remain SMALL during the license renewal term.

- Heat shock – This issue addresses mortality of aquatic organisms by exposure to heated plant effluent. The studies discussed above also addresses the impact from heat shock and requirements of 316(a) of the federal Clean Water Act and NYSDEC regulations. Temperature limitations established by the NYSDEC in SPDES permit NY-0004472 to ensure the protection and propagation of a balanced indigenous population of shellfish, fish, and wildlife in the Hudson River are being met. In addition, as discussed above, the sites' discharges were designed, and are operated, to minimize potential adverse impacts. Therefore, Entergy concludes that heat discharge from the sites' cooling systems does not cause appreciable harm or interfere with the maintenance of a balanced indigenous aquatic population and that impacts will remain SMALL during the license renewal period.

- Threatened or endangered species

Four animal species currently protected and two candidate species under the Endangered Species Act have geographic ranges which could possibly include the site (see Table D-2). Federally protected and candidate species potentially represented include two fish, two mammals, one reptile, and one bird. These are the shortnose sturgeon (*Acipenser brevirostrum*), Atlantic sturgeon (*Acipenser oxyrhynchus*), Indiana bat (*Myotis sodalis*), New England cottontail rabbit (*Sylvilagus transitionalis*), bog turtle (*Clemmys muhlenbergii*), and bald eagle (*Haliaeetus leucocephalus*). Of these species, the Indiana bat and the shortnose sturgeon are listed as endangered, the bog turtle and bald eagle are listed as threatened, and the Atlantic sturgeon and the New England cottontail rabbit are listed as candidate species. There have been no sightings of the Indiana bat or bog turtle either onsite or within the vicinity of the site.

The shortnose sturgeon is the only aquatic species listed as threatened or endangered in the vicinity of IP2 and IP3. Entergy received USFWS and NMFS input on the presence of listed species in the vicinity of Indian Point in January 2007. Both agencies identified the shortnose sturgeon in the vicinity of Indian Point. NMFS also mentioned the presence of the Atlantic sturgeon in the vicinity of Indian Point, which the agency is considering as a Candidate Species, and has initiated a status review for threatened or endangered species listing. However, the NMFS has previously stated in biological assessments involving the shortnose sturgeon that, overall, the intakes and discharges of Hudson River power plants are unlikely to jeopardize the recovery of the Hudson River shortnose sturgeon population [NMFS].

Bald eagles have increased in total number, successful nesting pairs, and number of young produced. Alteration of the landscape required by bald eagles continues to be the biggest single threat to this species. Since there are no plans to alter operations, expand existing facilities, or acquire additional land in support of license renewal, therefore no anticipated potential impacts on nesting sites from continued site operations. Even so, Entergy has fleet procedural controls in place to ensure that threatened and endangered species are adequately protected, if present, during site operations and project planning.

Therefore, Entergy concludes that impacts from IP2 and IP3 plant operations to the species discussed above are SMALL and has no plans that would change this conclusion for the license renewal term.

- Human health

Electromagnetic fields, acute effects (electric shock) – This issue addresses the potential for shock from induced currents, similar to static electricity effects, in the vicinity of transmission lines. Because this strictly human-health issue does not directly or indirectly affect natural resources of concern within the Coastal Zone Management Act definition of "coastal zone" [16 USC 1453(1)], Entergy concludes that the issue is not subject to the certification requirement.

- Socioeconomics

  - ♦ Housing – This issue addresses impacts that IP2 and IP3 employees required to support license renewal could have on local housing availability. The NRC concluded, and Entergy concurs, that the operation of Indian Point has not considerably affected the housing in the communities neighboring the plants or in the whole of Westchester or Dutchess counties [NRC, 1996, D-2, Section C.4.4.2.1]. Further, the NRC concluded that impacts related to housing value and marketability that occur during the license renewal term are the same as those currently experienced. As Entergy does not intend to add additional permanent employees to the IP2 and IP3 workforce, Entergy has concluded that impacts during the IP2 and IP3 license renewal term would be SMALL.

  - ♦ Public services: public utilities – This issue addresses impacts that adding license renewal workers could have on public water supply systems. Entergy has analyzed the availability of public water supplies in candidate locales and has found no limitations that would suggest that the IP2 and IP3 workforce would cause adverse impacts on the public water supply. As Entergy does not intend to add additional permanent employees to the IP2 and IP3 workforce, Entergy has concluded that impacts during the license renewal term would be SMALL.

  - ♦ Offsite land use – This issue addresses impacts on land use patterns from local government spending of plant PILOT and property tax dollars. IP2 and IP3 PILOT payments comprise approximately 39 percent of the Village of Buchanan revenues and Entergy expects this to remain generally unchanged during the license renewal term. The NRC concluded, and Entergy concurs, that impacts to offsite land use would be small if tax payments continue at approximately the same level. Therefore, Entergy concludes that impacts during the IP2 and IP3 license renewal term would be SMALL.

- Public services: transportation – This issue addresses impacts that adding license renewal workers could have on local traffic patterns. As Entergy does not intend to add additional employees to the permanent workforce for the license renewal term, this would result in SMALL impacts.

- Historic and archaeological resources – This issue addresses impacts that license renewal activities could have on resources of historic or archaeological significance. Although a number of archaeological or historic sites have been identified near the IP2 and IP3 site, none have been identified on plant property. Therefore, since no refurbishment activities are required and there are also no plans to alter operations, expand existing facilities, or disturb additional land in support of license renewal, Entergy concludes that impacts during the license renewal term would be SMALL. Entergy's correspondence with the New York State Historic Preservation Officer (SHPO) also supports this conclusion since the SHPO identified no issues of concern.

State Program

The New York State Coastal Management Program is administered by the Division of Coastal Resources within the New York State Department of State (NYSDOS). The office maintains a website that describes the program in general terms [NYDS]. The New York State Coastal Management Program [SEL] contains details about the state's enforceable policies and management principles. Table D-1 lists these policies and discusses for each item the applicability to IP2 and IP3 and, where applicable, the status of IP2 and IP3 compliance.

Findings

1. The NRC has found that the environmental impacts of Category 1 issues are SMALL. Entergy has adopted by reference NRC findings for Category 1 issues applicable to IP2 and IP3.

2. For Category 2 issues applicable to IP2 and IP3, Entergy has determined that the environmental impacts are SMALL.

3. IP2 and IP3 are in compliance with New York State licensing and permitting requirements and are in compliance with its local government-issued licenses and permits.

4. Entergy's license renewal and continued operation of IP2 and IP3 would be consistent with the enforceable policies of the New York State Coastal Management Program.

STATE NOTIFICATION

By this certification that IP2 and IP3 license renewal is consistent with the New York State Coastal Management Program, the New York State Department of State is notified that it has six months from receipt of this letter and accompanying information in which to concur with or object to Entergy's certification. However, pursuant to the New York State Coastal Management Program and 15 CFR Part 930, if the New York State Department of State has not

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issued a decision within three months following the commencement of state agency review, it shall notify the contacts listed below of the status of the matter and the basis for further delay. The New York State Department of State's concurrence, objection, or notification of review status shall be sent to:

Bo Pham U.S. Nuclear Regulatory Commission One White Flint North 11555 Rockville Pike Rockville, MD 20852-2738	Fred Dacimo Site Vice President Indian Point Energy Center 450 Broadway, Suite 1 Buchanan, NY 10511

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Council, Inc. et. al. vs. New York State Department of Environmental Conservation and Consolidated Edison Company of New York, Inc, New York Power Authority, Orange and Rockland Utilities, Inc., and Central Hudson Gas and Electric Corp.

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SEL (State Executive Law). Department of State regulations, Article 42, 19 NYCRR Part 600, Coastal Management Program.

USFWS (U.S. Fish and Wildlife Service). 2005, Federally listed and proposed endangered, threatened, and candidate species in New York. USFWS New York and Long Island Field Offices, accessed on January 11, 2006 at http://www.fws.gov/northeast/nyfo/es/list.htm.

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Table D-1
New York State Coastal Management Program's
New York State Coastal Policies

The New York State Coastal Management Program (NYSCMP) policies are contained in the Article 42 of the State Executive Law (SEL), Department of State regulations in 19 NYCRR Part 600, and the State Environmental Quality Review Act (SEQRA) 6 NYCRR Part 617 and requires persons seeking approval for activities which may impact the Coastal Zone to demonstrate that the activity is consistent with all enforceable policies in 19 NYCRR Part 600 and 6 NYCRR Part 617. Entergy is seeking renewal of the operating licenses for IP2 and IP3. The following table details the NYSCMP policies of 19 NYCRR Part 600 and provides Entergy's demonstration that IP2 and IP3 license renewal would be consistent with 19 NYCRR Part 600.

POLICY	JUSTIFICATION/ CONSISTENCY
DEVELOPMENT POLICIES	
DEVELOPMENT POLICY #1: Restore, revitalize, and redevelop deteriorated and underutilized waterfront areas for commercial, industrial, cultural, recreational, and other compatible uses.	IP2 and IP3 license renewal is not an action involving underutilized waterfront areas. IP2 and IP3 have no plans for additional activities or development along the waterfront as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
DEVELOPMENT POLICY #2: Facilitate the siting of water dependent uses and facilities on or adjacent to coastal waters.	The renewal of the IP2 and IP3 Operating Licenses would have no effect on the water dependant uses on or adjacent to coastal waters. IP2 and IP3 have no plans for development along the waterfront as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
DEVELOPMENT POLICY #3: Further develop the state's major ports of Albany, Buffalo, New York, Ogdensburg, and Oswego as centers of commerce and industry, and encourage the siting, in these port areas, including those under the jurisdiction of state public authorities, of land use and development which is essential to, or in support of, the waterborne transportation of cargo and people.	The renewal of the IP2 and IP3 Operating Licenses would have no impact on the State's major ports. IP2 and IP3 have no plans for additional development along the waterfront as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
DEVELOPMENT POLICY #4: Strengthen the economic base of smaller harbor areas by encouraging the development and enhancement of those traditional uses and	IP2 and IP3 are not a small harbor area and license renewal would have no known impact on any smaller harbor areas. In addition, IP2 and IP3 have no plans for additional activities

POLICY	JUSTIFICATION/ CONSISTENCY
activities which have provided such areas with their unique maritime identity.	or development along the waterfront as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
DEVELOPMENT POLICY #5: Encourage the location of development in areas where public services and facilities essential to such development are adequate.	The renewal of the IP2 and IP3 Operating Licenses would have no identified impact on the development of the existing built environment. In addition, IP2 and IP3 have no plans for additional development as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
DEVELOPMENT POLICY #6: Expedite permit procedures in order to facilitate the siting of development activities at suitable locations.	The renewal of the IP2 and IP3 Operating Licenses would have no identified impact on expediting permit procedures to facilitate siting of development activities. In addition, IP2 and IP3 have no plans for additional activities or development as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
FISH AND WILDLIFE POLICIES	
FISH AND WILDLIFE POLICY #7: Significant coastal fish and wildlife habitats will be protected, preserved, and where practical, restored so as to maintain their viability as habitats.	IP2 and IP3 have not identified any impact that license renewal operations would have on the significant coastal fish and wildlife habitat. In addition, IP2 and IP3 have no plans for additional activities or development along the waterfront as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
FISH AND WILDLIFE POLICY #8: Protect fish and wildlife resources in the coastal area from the introduction of hazardous wastes and other pollutants which bio-accumulate in the food chain or which cause significant sub-lethal or lethal effects on those resources.	IP2 and IP3 operations are consistent with SPDES permit requirements which are based on federal and state water quality standards. All non-radiological effluent discharges are regulated by the New York State Department of Environmental Conservation (NYSDEC) through the State Pollutant Discharge Elimination System (SPDES) permit program. IP2 and IP3 has four such SPDES permits (NY-0004472, NY-0234826, NY-0250414, NY-0251135) with effluent limitations, monitoring requirements, and other conditions that ensures that all discharges are in compliance

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POLICY	JUSTIFICATION/ CONSISTENCY
	with Title 8 of Article 17 of the Environmental Conservation Law (ECL) of New York State and the Clean Water Act (CWA), as amended (33 USC. Section 1251 et seq.). Concentrations of radioactivity in effluents are subject to the requirements of the NRC. IP2 and IP3 are in compliance with its licensing requirements, as well as the requirements and conditions of its SPDES permits. Therefore, it is protecting fish and wildlife resources in the Hudson River area where the plant is located. Pesticide use is regulated by the NYSDEC under 6 NYCRR Part 325. IP2 and IP3 have in place the appropriate NYSDEC Pesticide Business Registrations, submit the required annual reports to the State, and maintain appropriate applicator certifications to ensure that pesticide use and storage on-site are conducted properly and in accordance with regulations. Therefore, it is protecting fish and wildlife resources in the Hudson River area where the plant is located. Petroleum bulk storage on-site is regulated by the NYSDEC under 6 NYCRR Parts 612-614 for IP3, and 6 NYCRR Parts 610-614 and 17 NYCRR Parts 30 and 32 for IP2. IP2 and IP3 facilities have the appropriate registrations and procedures in place for spill prevention, response, and reporting. Onsite chemical bulk storage is regulated by the NYSDEC under 6 NYCRR Parts 595-599. IP2 and IP3 have in place Spill Prevention, Control, and Countermeasures Plans, as required under 40 CFR Part 112, to prevent the discharge of oil to surface waters or surface water tributaries. IP2 and IP3 also have in place Chemical Spill Prevention Plans, as required by 6 NYCRR Part 598, to prevent the discharge of hazardous chemicals to surface waters and their tributaries. IP2 and IP3 facilities have the appropriate registrations and procedures in place for proper materials handling and storage; spill prevention, response, and reporting; and storage systems inspection,

POLICY	JUSTIFICATION/ CONSISTENCY
	maintenance, and repair. IP2 and IP3 have in place processes and procedures to ensure that hazardous chemicals stored and used on-site are handled and stored in accordance with applicable State and Federal regulations. IP2 and IP3 are, therefore, protecting fish and wildlife resources in the Hudson River area. Hazardous and some mixed wastes generated on-site are packaged, temporarily stored, and shipped off-site for processing and disposal. The NYSDEC regulates these activities under 6 NYCRR Parts 370-376. In addition, IP2 has a NYSDEC permit for the storage of mixed wastes and both IP2 and IP3 have EPA permits for the storage of mixed wastes. These activities are also regulated under 6 NYCRR Parts 370–376, as well as 40 CFR Parts 260-268. IP2 and IP3 have in place processes and procedures to ensure that mixed and hazardous wastes are packaged, stored, and shipped so as to comply with the applicable State and Federal regulations, thus ensuring that fish and wildlife resources are protected. Therefore, fish and wildlife resources in the Hudson River area are protected and the proposed activity is consistent with this policy.
FISH AND WILDLIFE POLICY #9: Expand recreational use of fish and wildlife resources in coastal areas by increasing access to existing resources, supplementing existing stocks, and developing new resources.	Water-dependent and water-enhanced recreation along the IP2 and IP3 waterfront cannot be encouraged or facilitated for reasons of national security. In light of the events of September 11, 2001, heightened security concerns preclude encouragement of recreational use of IP2 and IP3's waterfront and other property by the general public.

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POLICY	JUSTIFICATION/ CONSISTENCY
FISH AND WILDLIFE POLICY #10: Further develop commercial finfish, shellfish, and crustacean resources in the coastal area by encouraging the construction of new, or improvement of existing on-shore commercial fishing facilities, increasing marketing of the states seafood products, maintaining adequate stocks, and expanding aquaculture facilities.	Water-dependent and water-enhanced development along the IP2 and IP3 waterfront cannot be encouraged or facilitated for reasons of national security. In light of the events of September 11, 2001, heightened security concerns preclude encouragement of recreational use of IP2 and IP3's waterfront and other property by the general public.
FLOODING AND EROSION HAZARDS POLICIES	
FLOODING AND EROSION HAZARDS POLICY #11: Buildings and other structures will be sited in the coastal area so as to minimize damage to property and the endangering of human lives caused by flooding and erosion.	Entergy is aware of no IP2 and IP3 impacts on coastal areas that damage property or endanger human lives due to flooding or erosion. IP2 and IP3 have no plans for refurbishment or development as a part of the proposed activity, and therefore the proposed activity is consistent with this policy.
FLOODING AND EROSION HAZARDS POLICY #12: Activities or development in the coastal area will be undertaken so as to minimize damage to natural resources and property from flooding and erosion by protecting natural protective features including beaches, dunes, barrier islands, and bluffs.	The shoreline within the IP2 and IP3 protected area has been evaluated according to its geological characteristics. The area is one in which severe natural phenomena such as tornados and flooding are uncommon. The continued operation of IP2 and IP3 during the license renewal period would not involve any activities that would disturb the shoreline along the IP2 and IP3 property. In addition, IP2 and IP3 have no plans for refurbishment or development along the shoreline as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
FLOODING AND EROSION HAZARDS POLICY #13: The construction or reconstruction of erosion protection structures shall be undertaken only if they have a reasonable probability of controlling erosion for at least thirty years as demonstrated in design and construction standards and/or assured maintenance or replacement programs.	IP2 and IP3 license renewal will not necessitate any construction or refurbishment activities. Therefore, the proposed activity is consistent with this policy.

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POLICY	JUSTIFICATION/ CONSISTENCY
FLOODING AND EROSION HAZARDS POLICY #14: Activities and development, including the construction or reconstruction of erosion protection structures, shall be undertaken so that there will be no measurable increase in erosion or flooding at the site of such activities or development, or at other locations.	IP2 and IP3 are aware of no impacts that would result from the renewal of the IP2 and IP3 Operating Licenses on erosion hazard areas. In addition, IP2 and IP3 have no plans for additional development as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
FLOODING AND EROSION HAZARDS POLICY #15: Mining, excavation or dredging in coastal waters shall not significantly interfere with the natural coastal processes which supply beach materials to land adjacent to such waters and shall be undertaken in a manner which will not cause an increase in erosion of such land.	The renewal of the IP2 and IP3 Operating Licenses would have no impact on coastal waters due to dredging, mining, or excavation. Any potential dredging to remove sediment build-up in the vicinity of IP2 and IP3 intake or discharge structures would be completed in compliance with state and federal regulations that will ensure the action does not significantly interfere with natural coastal processes. Therefore, the proposed activity is consistent with this policy.
FLOODING AND EROSION HAZARDS POLICY #16: Public funds shall only be used for erosion protective structures where necessary to protect human life, and new development which requires a location within or adjacent to an erosion hazard area to be able to function, or existing development; and only where the public benefits outweigh the long term monetary and other costs including the potential for increasing erosion and adverse effects on natural protective features.	IP2 and IP3 are privately owned facilities and renewal of their Operating Licenses are not a state or federally funded project.
FLOODING AND EROSION HAZARDS POLICY #17: Non-structural measures to minimize damage to natural resources and property from flooding and erosion shall be used whenever possible.	The shoreline within the IP2 and IP3 protected area has been evaluated according to its geological characteristics. The area is one in which severe natural phenomena such as tornados and flooding is uncommon. The continued operation of IP2 and IP3 during the license renewal period will not involve any activities that would disturb the shoreline along the IP2 and IP3 property. In addition, IP2 and IP3 have no plans for additional activities or development along the shoreline as a part of the proposed activity; therefore the proposed

POLICY	JUSTIFICATION/ CONSISTENCY
	activity is consistent with this policy.
GENERAL POLICY	
GENERAL POLICY #18: To safeguard the vital economic, social, and environmental interests of the state and of its citizens, proposed major actions in the coastal area must give full consideration to those interests, and to the safeguards which the state has established to protect valuable coastal resource areas.	IP2 and IP3 license renewal will have significant positive impact on the economic and social interest of New York State and its citizens from contributions to the tax base, education funding, support of public services infrastructure, and workforce. Entergy is aware of no negative impacts that continued operations would have on valuable coastal resource areas.
PUBLIC ACCESS POLICIES	
PUBLIC ACCESS POLICY #19: Protect, maintain, and increase the level and types of access to water-related recreation resources and facilities.	Water-dependent and water-enhanced recreation along the IP2 and IP3 waterfront cannot be encouraged or facilitated for reasons of national security. In light of the events of September 11, 2001, heightened security concerns preclude encouragement of recreational use of IP2 and IP3's waterfront and other property by the general public.
PUBLIC ACCESS POLICY #20: Access to the publicly-owned foreshore and to lands immediately adjacent to the foreshore or the water's edge that are publicly owned shall be provided and it shall be provided in a manner compatible with adjoining uses.	Water-dependent and water-enhanced recreation along the IP2 and IP3 waterfront cannot be encouraged or facilitated for reasons of national security. In light of the events of September 11, 2001, heightened security concerns preclude encouragement of recreational use of IP2 and IP3's waterfront and other property by the general public.
RECREATION POLICIES	
RECREATION POLICY #21: Water-dependent and water-enhanced recreation will be encouraged and facilitated, and will be given priority over non-water-related uses along the coast.	Water-dependent and water-enhanced recreation cannot be encouraged or facilitated for reasons of national security. In light of the events of September 11, 2001, heightened security concerns preclude encouragement of recreational use of IP2 and IP3's waterfront and other property by the general public.

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POLICY	JUSTIFICATION/ CONSISTENCY
RECREATION POLICY #22: Development, when located adjacent to the shore, will provide for water-related recreation, whenever such is compatible with reasonably anticipated demand for activities, and is compatible with the primary purpose of the development.	Water-dependent and water-enhanced recreation cannot be encouraged or facilitated for reasons of national security. In light of the events of September 11, 2001, heightened security concerns preclude encouragement of recreational use of IP2 and IP3's waterfront and other property by the general public.
HISTORIC AND SCENIC RESOURCES POLICIES	
HISTORIC AND SCENIC RESOURCES POLICY #23: Protect, enhance, and restore structures, districts, areas, or sites that are of significance in the history, architecture, archaeology, or culture of the state, its communities, or the nation.	The renewal of the IP2 and IP3 Operating Licenses will have no impact on historic and cultural resources. In addition, IP2 and IP3 have no plans for refurbishment or development along the waterfront as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
HISTORIC AND SCENIC RESOURCES POLICY #24: Prevent impairment of scenic resources of statewide significance.	The renewal of the IP2 and IP3 Operating Licenses will have no impairment impact on the significant scenic resources. In addition, IP2 and IP3 have no plans for additional activities or development along the waterfront as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
HISTORIC AND SCENIC RESOURCES POLICY #25: Protect, restore, or enhance natural and man-made resources which are not identified as being of statewide significance, but which contribute to the overall scenic quality of the coastal area.	The renewal of the IP2 and IP3 Operating Licenses will have no additional impact on the scenic resources in the coastal area. In addition, IP2 and IP3 have no plans for additional activities or development along the waterfront as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
AGRICULTURAL LANDS POLICY	
AGRICULTURAL LANDS POLICY #26: Conserve and protect agricultural lands in the state’s coastal area.	IP2 and IP3 have no plans for additional activities or development along the waterfront as a part of the proposed activity; therefore the proposed activity is consistent with this policy.

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POLICY	JUSTIFICATION/ CONSISTENCY
ENERGY AND ICE MANAGEMENT POLICIES	
ENERGY AND ICE MANAGEMENT POLICY #27: Encourage energy conservation and the use of alternative sources such as solar and wind power in order to assist in meeting the energy needs of the State.	IP2 and IP3 are important power generation facilities that plays a vital role to assist in meeting the energy needs of the State, without which other sources of energy would be required that could cause environmental or quality of life impacts for the citizens of New York.
ENERGY AND ICE MANAGEMENT POLICY #28: Ice management practices shall not interfere with the production of hydroelectric power, damage significant fish and wildlife and their habitats, or increase shoreline erosion or flooding.	IP2 and IP3 operations and license renewal do not involve ice management practices.
ENERGY AND ICE MANAGEMENT POLICY #29: Encourage the development of energy resources on the outer continental shelf, in Lake Erie and in other water bodies, and ensure the environmental safety of such activities.	IP2 and IP3 are important power generation facilities that plays a vital role in meeting the energy needs of the State of New York, without which other sources of energy would be required that could cause environmental or quality of life impacts for the citizens of New York.
WATER AND AIR RESOURCES POLICIES	
WATER AND AIR RESOURCES POLICY #30: Municipal, industrial, and commercial discharge of pollutants, including but not limited to, toxic and hazardous substances, into coastal waters will conform to state and national water quality standards.	The effluent discharges from IP2 and IP3 are regulated by the NYSDEC through the SPDES permit program. IP2 and IP3 have been issued four SPDES permits (NY-0004472, NY-0234826, NY-0250414, NY-0251135) with effluent limitations, monitoring requirements, and other conditions that ensure that all discharges are in compliance with Title 8 of Article 17 of the ECL of New York State and the CWA, as amended (33 USC Section 1251 et seq.). Concentrations of radioactivity in effluents are subject to the requirements of the NRC. IP2 and IP3 are in compliance with its licensing requirements, as well as the requirements and conditions of its SPDES permits. Therefore, the proposed activity is consistent with this policy.

TO BE SUBMITTED AT LATER DATE

POLICY	JUSTIFICATION/ CONSISTENCY
WATER AND AIR RESOURCES POLICY #31: State coastal area policies and management objectives of approved local waterfront revitalization programs will be considered while reviewing coastal water classifications and while modifying water quality standards; however those waters already overburdened with contaminants will be recognized as being a development constraint.	The effluent discharges from IP2 and IP3 are regulated by the NYSDEC through the SPDES permit program. IP2 and IP3 have been issued four SPDES permits (NY-0004472, NY-0234826, NY-0250414, NY-0251135) with effluent limitations, monitoring requirements, and other conditions that ensure that all discharges are in compliance with Title 8 of Article 17 of the ECL of New York State and the CWA, as amended (33 USC Section 1251 et seq.). Concentrations of radioactivity in effluents are subject to the requirements of the NRC. IP2 and IP3 are in compliance with its licensing requirements, as well as the requirements and conditions of its SPDES permits. Therefore, the proposed activity is consistent with this policy.
WATER AND AIR RESOURCES POLICY #32: Encourage the use of alternative or innovative sanitary waste systems in small communities where the costs of conventional facilities are unreasonably high, given the size of the existing tax base of these communities.	IP2 and IP3 provide approximately 39 percent of the tax revenue for the Village of Buchanan, and is a major contributor to the tax base of Westchester County. IP2 and IP3 license renewal will have significant positive impact on the economic and social impact from contributions to the tax base, education funding, support of public services infrastructure, and workforce.
WATER AND AIR RESOURCES POLICY #33: Best management practices will be used to ensure the control of stormwater runoff and combined sewer overflows draining into coastal waters.	IP2 and IP3 have in place four SPDES permits (NY-0004472, NY-0234826, NY-0250414, and NY-0251135) that incorporate best management practices to control storm water runoff. The NYSDEC regulates storm water management under 6 NYCRR Part 750, ECL 17-0808, and GP-06-002. IP2 and IP3 have programs and processes in place to ensure compliance with applicable NYSDEC storm water management requirements. Therefore, the proposed activity is consistent with this policy.

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POLICY	JUSTIFICATION/ CONSISTENCY
WATER AND AIR RESOURCES POLICY #34: Discharge of waste materials into coastal waters from vessels subject to state jurisdictions will be limited so as to protect significant fish and wildlife habitats, recreational areas and water supply areas.	IP2 and IP3 operations and license renewal do not involve discharge of waste materials into coastal waters from vessels. Therefore, the proposed activity is consistent with this policy.
WATER AND AIR RESOURCES POLICY #35: Dredging and filling coastal waters and disposal of dredged material will be undertaken in a manner that meets existing state permit requirements, and protects significant fish and wildlife habitats, scenic resources, natural protective features, important agricultural lands and wetlands.	IP2 and IP3 have no plans for mining, excavation, filling activities, or development along the waterfront as a part of license renewal operations. Any potential dredging to remove sediment build-up in the vicinity of IP2 and IP3 intake or discharge structures would be completed in compliance with state and federal regulations that will ensure the action does not significantly interfere with fish or wildlife habitats, scenic resources, important agricultural lands, or wetlands. Therefore, the proposed activity is consistent with this policy.
WATER AND AIR RESOURCES POLICY #36: Activities related to the shipment and storage of petroleum and other hazardous materials will be conducted in a manner that will prevent or at least minimize spills into coastal waters; all practicable efforts will be undertaken to expedite the cleanup of such discharges; and restitution for damages will be required when these spills occur.	IP2 and IP3 has in place procedures to ensure that petroleum and other hazardous materials used on-site are safely handled and stored. The NYSDEC regulates petroleum bulk storage under the authority of 6 NYCRR Parts 610-614 and 17 NYCRR Parts 30 and 32. IP2 and IP3 facilities have the appropriate registrations, licenses, and procedures in place to prevent and report spills. Onsite chemical bulk storage is regulated by the NYSDEC under 6 NYCRR Parts 595-599. IP2 and IP3 have in place Spill Prevention, Control, and Countermeasures Plans as required under 40 CFR 112 to prevent the discharge of oil to surface waters or surface water tributaries. IP2 and IP3 also have in place Chemical Spill Prevention Plans, as required by 6 NYCRR Part 598, to prevent the discharge of hazardous chemicals to surface waters and their tributaries. IP2 and IP3 facilities have the appropriate registrations and procedures in place for proper materials handling and storage; spill prevention, response, and reporting; and storage systems inspection, maintenance, and repair. IP2 and IP3 also have in place processes and

POLICY	JUSTIFICATION/ CONSISTENCY
	procedures to ensure that hazardous chemicals stored and used on-site are managed in accordance with applicable State and Federal regulations so as to prevent the release of these materials to coastal waters. Therefore, the proposed activity is consistent with this policy.
WATER AND AIR RESOURCES POLICY #37: Best management practices will be utilized to minimize the non-point discharge of excess nutrients, organics, and eroded soils into coastal waters.	IP2 and IP3 have in place four SPDES permits (NY-0004472, NY-0234826, NY-0250414, and NY-0251135) that incorporate best management practices to control storm water runoff. The NYSDEC regulates storm water management under 6 NYCRR Part 750, ECL 17-0808, and GP-06-002. IP2 and IP3 have programs and processes in place to ensure compliance with applicable NYSDEC storm water management requirements. The EPA has authority under 40 CFR 122. Therefore, the proposed activity is consistent with this policy.
WATER AND AIR RESOURCES POLICY #38: The quality and quantity of surface water and groundwater supplies will be conserved and protected particularly where such waters constitute the primary or sole source of water supply.	IP2 and IP3 do not use groundwater as a resource for any plant operations or as a potable water source. Processes and procedures are in place for the handling and storage of hazardous materials on-site to prevent spills and to respond to any that occur so as to minimize impacts to groundwater or surface water resources. Effluents from plant operations are regulated under IP2 and IP3's SPDES permits so as to minimize the impacts to surface water supplies (Hudson River) and minimize water use. SPCC Plans are in place to protect surface water resources as required under 40 CFR 112, to prevent the discharge of oil to surface waters or surface water tributaries. IP2 and IP3 have in place processes and procedures that conserve and protect both groundwater and surface water resources. Radiological effluents are regulated in accordance with NRC regulations, policies, and guidance. Therefore, the proposed activity is consistent with this policy.

TO BE SUBMITTED AT LATER DATE

POLICY	JUSTIFICATION/ CONSISTENCY
WATER AND AIR RESOURCE S POLICY #39: The transport, storage, treatment, and disposal of solid wastes, particularly hazardous wastes, within coastal areas will be conducted in such a manner so as to protect groundwater and surface water supplies, significant fish and wildlife habitats, recreation areas, important agricultural land, and scenic resources.	IP2 and IP3 do not dispose of solid waste on-site. Hazardous and some mixed wastes generated on-site are packaged, temporarily stored, and shipped off-site for processing and disposal. The NYSDEC regulates these activities under 6 NYCRR Parts 370-376. In addition, IP2 has a NYSDEC permit for the storage of mixed wastes and both IP2 and IP3 have EPA permits for the storage of mixed wastes. These activities are also regulated under 6 NYCRR Parts 370-376, as well as 40 CFR Parts 260-268. IP2 and IP3 have in place processes and procedures to ensure that mixed and hazardous wastes are packaged, stored, and shipped in compliance with the applicable State and Federal regulations, thus ensuring that groundwater and surface water supplies, significant fish and wildlife habitats, recreation areas, important agricultural land, and scenic resources are protected. The proposed activity is, therefore, consistent with this policy.
WATER AND AIR RESOURCES POLICY #40: Effluent discharged from major steam electric generating and industrial facilities into coastal waters will not be unduly injurious to fish and wildlife and shall conform to state water quality standards.	The effluent discharges from IP2 and IP3 are regulated by the NYSDEC through the SPDES permit program. The site has been issued four SPDES permits (NY-0004472, NY-0234826, NY-0250414, NY-0251135) with effluent limitations, monitoring requirements, and other conditions that ensure that all discharges are in compliance with Title 8 of Article 17 of the ECL of New York State and the CWA, as amended (33 USC Section 1251 et seq.). IP2 and IP3 are in compliance with its SPDES permits and are meeting all requirements and conditions set forth in the permits, and it is minimizing impacts to fish and wildlife. The proposed activity is, therefore, consistent with this policy.

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POLICY	JUSTIFICATION/ CONSISTENCY
WATER AND AIR RESOURCES POLICY #41: Land use or development in the coastal area will not cause national or state air quality standards to be violated.	The air discharges from IP2 and IP3 are regulated under the Westchester County Department of Health (WCDOH), Chapter 873, Article XIII of the Laws of Westchester County, the ECL of New York State, and 6 NYCRR Parts 200-201 and 227. IP2 and IP3 have been issued Air State Facility permits (3-5522-00011/00026 and 3-5522-00105/00009) with permissible emissions, monitoring requirements, and other conditions that ensure that all emissions are in compliance with Article XIII of the WCDOH and Article 19: Air Pollution Control – Air State Facility Permit under the ECL. IP2 and IP3 are in compliance with its Air State Facility permit and are meeting all requirements and conditions set forth in the permit, and it is minimizing impacts to the air quality within the coastal area. The proposed activity is therefore consistent with this policy.
WATER AND AIR RESOURCES POLICY #42: Coastal management policies will be considered if the state reclassifies land areas pursuant to the prevention of significant deterioration regulations of the federal Clean Air Act.	The renewal of the IP2 and IP3 Operating Licenses would have no known impact if the state reclassifies land areas pursuant to the PSD regulations of the federal Clean Air Act. IP2 and IP3 have no plans for refurbishment or development as a part of the proposed activity; therefore the proposed activity is consistent with this policy.
WATER AND AIR RESOURCES POLICY #43: Land use or development in the coastal areas must not cause the generation of significant amounts of acid rain precursors: nitrates and sulfates.	IP2 and IP3 license renewal provides a vital role to meeting the power generation and energy needs of the State, and does so without the production of acid rain precursors, nitrates, or sulfates.
WETLANDS POLICY	
Wetlands Policy #44: Preserve and protect tidal and freshwater wetlands and preserve the benefits derived from these areas.	IP2 and IP3 operations do not degrade the tidal wetlands in the area of the IP2 and IP3 facilities, no state or federal jurisdictional tidal or freshwater wetlands exist on the IP2 and IP3 property, and IP2 and IP3 have no plans for additional activities or development along the waterfront as a part of license renewal.

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Table D-2
Federally-Listed Threatened or Endangered Species Possibly Occurring at IP2 and IP3, Westchester County, New York

Common Name	Scientific Name	Federal Status*	State Status
Shortnose sturgeon	*Acipenser brevirostrum*	E	E
Bog turtle	*Clemmys muhlenbergii*	T	E
Bald eagle	*Haliaeetus leucocephalus*	T	T
Indiana bat	*Myotis sodalis*	E	E
Atlantic Sturgeon	*Acipenser oxyrhynchus*	C	
New England cottontail rabbit	*Sylvilagus transitionalis*	C	

* E = Endangered; T = Threatened; C = Candidate species
Source: USFWS, NYSDEC 2000, NYNHP 2006a, NYNHP 2006b, and NMFS.

Table D-3
Environmental Authorizations for Current IP2 and IP3 Operations

Agency	Authority	Requirement	Number	Expiration Date	Authorized Activity
NRC	Atomic Energy Act, 10 CFR 50	IP1 License to Possess	DPR-5	September 28, 2013	Maintain IP1 in SAFSTOR condition.
NRC	Atomic Energy Act, 10 CFR 50	IP2 License to Operate	DPR-26	September 28, 2013	Operation of IP2.
NRC	Atomic Energy Act, 10 CFR 50	IP3 License to Operate	DPR-64	December 12, 2015	Operation of IP3.
DOT	49 CFR 107, Subpart G	IP2 DOT Hazardous Materials Certificate of Registration	0627065520610Q	June 30, 2009	Radioactive and hazardous materials shipments.
DOT	49 CFR 107, Subpart G	IP3 DOT Hazardous Materials Certificate of Registration	0627065520690Q	June 30, 2009	Radioactive and hazardous materials shipments.
NYSDEC	6 NYCRR Part 325	IP2 Pesticide Application Business Registration	12696	April 30, 2009	Pesticide application.
NYSDEC	6 NYCRR Part 325	IP3 Pesticide Application Business Registration	13163	April 30, 2009	Pesticide application.
NYSDEC	6 NYCRR Parts 704 and 750	IP1, 2, and 3 SPDES Permit	NY 000 4472	October 1, 1992[1]	Discharge of wastewaters and stormwaters to waters of the State.

[1] Timely renewal application was submitted; therefore, permit is administratively continued under New York State Administrative Procedures Act.

Table D-3
Environmental Authorizations for Current IP2 and IP3 Operations

Agency	Authority	Requirement	Number	Expiration Date	Authorized Activity
NYSDEC	6 NYCRR Part 704	Simulator Transformer Vault SPDES Permit	NY 025 0414	March 1, 2008	Discharge of wastewaters to waters of the State.
NYSDEC	6 NYCRR Part 704	Tank Farm SPDES Permit	NY 025 1135	February 1, 2010	Discharge of wastewaters to waters of the State.
NYSDEC	6 NYCRR Part 704	Buchanan Gas Turbine SPDES Permit	NY 022 4826	March 1, 2008	Discharge of wastewaters to waters of the State.
NYSDEC	6 NYCRR Part 750	ISFSI Stormwater SPDES General Permit for Construction Activities	NYR 10H166	Not Applicable	Stormwater Discharge during Construction of the Dry Fuel Cask Storage.
NYSDEC	6 NYCRR Parts 200 and 201	IP2 Air Permit	3-5522-00011/00026	Not Applicable	Operation of air emission sources (boilers, turbines, and generators).
NYSDEC	6 NYCRR Parts 200 and 201	IP3 Air Permit	3/5522-00105/00009	Not Applicable	Operation of air emission sources (boilers, turbines, and generators).
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP2 Gas Turbine 1 Air Permit	#00021	December 31, 2006[2]	Operation of an air contamination source

[2] Timely renewal application was submitted; therefore permit is administratively continued by WCDOH.

Table D-3
Environmental Authorizations for Current IP2 and IP3 Operations

Agency	Authority	Requirement	Number	Expiration Date	Authorized Activity
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP2 Gas Turbine 2 Air Permit	#00022	December 31, 2006[2]	Operation of an air contamination source
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP2 Gas Turbine 3 Air Permit	#00023	December 31, 2006[2]	Operation of an air contamination source
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP2 Boiler Permit	52-4493	Not Applicable	Operation of an air contamination source
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP2 Vapor Extractor Air Permit	52-5682	December 31, 2006[2]	Operation of an air contamination source
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP3 Boiler Permit	52-6497	Not Applicable	Operation of an air contamination source

Table D-3
Environmental Authorizations for Current IP2 and IP3 Operations

Agency	Authority	Requirement	Number	Expiration Date	Authorized Activity
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP3 Training Center Boiler Permit	52-6498	Not Applicable	Operation of an air contamination source
WCDOH	Chapter 873, Article XIII, Section 873.1306.1 of the Laws of Westchester County	IP3 Vapor Extractor Air Permit	--[3]	--[3]	Operation of an air contamination source
NYSDEC	6 NYCRR Part 596	IP2 Hazardous Substance Bulk Storage Registration Certificate	3-000107	September 4, 2007	Onsite bulk storage of hazardous substances.
NYSDEC	6 NYCRR Part 596	IP3 Hazardous Substance Bulk Storage Registration Certificate	3-000071	August 16, 2008	Onsite bulk storage of hazardous substances.
NYSDEC	6 NYCRR Part 610	IP2 Major Oil Storage Facility	3-2140	--[4]	Onsite bulk storage of > 400K gallons of petroleum products.
WCDOH	Westchester County Sanitary Code, Article XXV	IP3 Petroleum Bulk Storage Registration Certificate	3-166367	September 7, 2010	Onsite bulk storage of petroleum products.

[3] Application has been submitted to WCDOH, but a permit has not been issued

[4] Application has been submitted to NYSDEC, but a permit has not been issued

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Table D-3
Environmental Authorizations for Current IP2 and IP3 Operations

Agency	Authority	Requirement	Number	Expiration Date	Authorized Activity
NYSDEC	6 NYCRR Part 372	IP2 Hazardous Waste Generator Identification	NYD000765073	Not Applicable	Hazardous waste generation
NYSDEC	6 NYCRR Part 372	IP3 Hazardous Waste Generator Identification	NYD000765073	Not Applicable	Hazardous waste generation
NYSDEC	6 NYCRR Part 373	IP2 Hazardous Waste Part 373 Permit	NYD991304411	February 28, 2007	Accumulation and temporary onsite storage of mixed waste for > 90 days.
EPA	40 CFR 264	IP2 Hazardous Solid Waste Amendment Permit	NYD991304411	October 14, 2002[5]	Accumulation and temporary onsite storage of mixed waste for > 90 days.
EPA	40 CFR 264	IP3 Hazardous Solid Waste Amendment Permit	NYD085503746	October 17, 2001[5]	Accumulation and temporary onsite storage of mixed waste for > 90 days.
SCDHEC	Act No. 429 of 1980, South Carolina Radioactive Waste Transportation and Disposal Act	IP2 Radioactive Waste Transport Permit	0019-31-07	December 31, 2007	Transportation of radioactive waste into the State of South Carolina
		IP3 Radioactive Waste Transport Permit	0072-31-07	December 31, 2007	

5 Permit has been administratively continued based on conditional mixed waste exemption.

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Table D-3
Environmental Authorizations for Current IP2 and IP3 Operations

Agency	Authority	Requirement	Number	Expiration Date	Authorized Activity
TDEC	Tennessee Department of Environment and Conservation Regulations	IP2 Radioactive Waste-License-for-Delivery	T-NY-010-L07	December 31, 2007	Shipment of radioactive material into Tennessee to a disposal/processing facility
		IP3 Radioactive Waste-License-for-Delivery	T-NY-005-L07	December 31, 2007	
		IP3 Radioactive Waste Disposal Permit	0072-31-07-X	December 31, 2007	

DOT: U.S. Department of Transportation
EPA: Environmental Protection Agency
NRC: U.S. Nuclear Regulatory Commission
NYSDEC: New York State Department of Environmental Conservation
SCDHEC: South Carolina Department of Health and Environmental Control
TDEC: Tennessee Department of Environment and Conservation (Division of Radiological Health)
WCDOH: Westchester County Department of Health

Attachment E

Severe Accident Mitigation Alternatives Analysis

Attachment E contains the following sections.

ATTACHMENT E

TABLE OF CONTENTS

ATTACHMENT E.1

EVALUATION OF IP2 PSA MODEL

E.1 EVALUATION OF IP2 PROBABILISTIC SAFETY ANALYSIS MODEL

The severe accident risk was estimated using the Probabilistic Safety Analysis (PSA) model and a Level 3 model developed using the most recent version (version 1.13.1) of the MELCOR Accident Consequences Code System version 2 (MACCS2) code. The CAFTA code was used to develop the Indian Point Unit 2 (IP2) PSA Level 1 and Level 2 models. This section provides the description of IP2 PSA Level 1, 2, and 3 analyses, core damage frequency (CDF) uncertainty, Individual Plant Examination of External Events (IPEEE) analyses, and PSA model peer review.

E.1.1 <u>PSA Model - Level 1 Analysis</u>

The PSA model (Level 1 and Level 2) used for the Severe Accident Mitigation Alternatives (SAMA) analysis is the most recent internal events risk model for IP2 (Revision 1, April 2007) [Reference E.1-3]. This model is an updated version of the model used in the 1992 Individual Plant Examination (IPE) [Reference E.1-1], converted from the RISKMAN platform to the CAFTA platform. It reflects the IP2 configuration and design as of December 2005 and uses component failure and unavailability data as of December 2005. The Revision 1 model resolves all findings and observations from the industry peer reviews conducted in May 2002 and July 2005. The IP2 PSA model adopts the small event tree / large fault tree approach and uses the CAFTA code for quantifying CDF.

The PSA model has been updated three times since the original IPE due to the following.

- Equipment performance: As data collection progresses, estimated failure rates and system unavailability data change.
- Plant configuration changes: Plant configuration changes are incorporated into the PSA model.
- Modeling changes: The PSA model is refined to incorporate the latest state of knowledge and recommendations from internal and industry peer reviews. The IP2 model was converted from RISKMAN to CAFTA platform for consistency with other Entergy sites.

The PSA model contains the major initiators leading to core damage with baseline CDFs listed in Table E.1-1.

The IP2 Revision 1 PSA model was reviewed to identify those potential risk contributors that made a significant contribution to CDF. CDF-based Risk Reduction Worth (RRW) rankings were reviewed down to 1.005. Events below this point would influence the CDF by less than 0.5% and are judged to be highly unlikely contributors for the identification of cost-beneficial enhancements. These basic events; including component failures, operator actions, and initiating events; were reviewed to determine if additional SAMA actions may need to be considered.

Table E.1-2 provides a correlation between the Level 1 RRW risk significant events (component failures, operator actions, and initiating events) down to 1.005 identified from the IP2 PSA model and the SAMAs evaluated in Section E.2.

Table E.1-1
IP2 PSA Model CDF Results by Major Initiators

Accident Type	Point Estimate CDF (/ry)	% Contribution to Point Estimate CDF
Loss of offsite power [1]	6.73×10^{-6}	37.56
Internal flooding	4.69×10^{-6}	26.19
Loss of coolant accident (LOCA)	1.49×10^{-6}	8.31
Transients [1]	1.21×10^{-6}	6.77
Anticipated transient without a scram (ATWS)	9.89×10^{-7}	5.52
Station blackout (SBO)	8.51×10^{-7}	4.75
Steam generator tube rupture (SGTR)	7.16×10^{-7}	4.00
Loss of component cooling water	5.83×10^{-7}	3.26
Loss of non-essential service water	3.00×10^{-7}	1.68
LOCAs outside containment (ISLOCA)	1.52×10^{-7}	0.85
Vessel rupture	1.00×10^{-7}	0.56
Loss of 125 VDC Power	5.77×10^{-8}	0.32
Total loss of service water	4.40×10^{-8}	0.25
Loss of essential service water [1]	1.93×10^{-10}	0.0011
Total	1.79×10^{-5}	100.00

1. Contributions to CDF from SBO and ATWS are listed separately and thus not included in the contributions shown for other accident types.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Description	Disposition
IE-T1	8.21E-02	1.716	Loss of offsite power	This term represents the loss of offsite power initiating event. Phase I SAMAs to enhance offsite power availability and coping with SBO events, including cross-tying diesel fuel oil supply lines, cross-tying AC and DC buses, and adding additional onsite power sources, have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EDG-ENG-FR-DG23R	1.55E-02	1.194	Diesel generator 23 fails to run	This term represents failure of (EDG) EDG 23 to continue to run. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
AFW-AOV-CC-P1139	8.98E-03	1.185	AFW turbine-driven pump 22 steam control valve PCV-1139 does not open	This term represents failure of steam control valve PCV-1139, leading to unavailability of auxiliary feedwater (AFW) turbine-driven pump 22 to provide water to the steam generators. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
AFW-MAI-MA-TDP22	6.70E-03	1.123	AFW turbine-driven pump 22 out for testing and maintenance	This term represents AFW turbine-driven pump 22 out for testing and maintenance. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
EDG-MAI-MA-EDG23	1.31E-02	1.117	Diesel generator 23 out for maintenance	This term represents EDG 23 out for maintenance. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
IE-TC15FP1	6.04E-05	1.109	Rupture of 10 inch fire protection piping in the deluge room adjacent to control building switchgear room	This term represents an internal flooding event due to rupture of a 10 inch fire protection piping deluge valve station adjacent to the control building switchgear room. Phase II SAMAs 054, 061, 062, and 065, providing a flood alarm, adding protection against flood propagation, providing a hard-wired connection to a SI pump from an alternate safe shutdown system (ASSS) power supply, and upgrading the ASSS to allow timely restoration of seal injection and cooling, were evaluated.
IE-T3	1.87E+00	1.094	Turbine trip with feedwater available initiator (T3)	This term represents an initiating event caused by a transient due to turbine trip with feedwater available. Industry efforts over the last twenty years have led to a significant reduction of plant scrams from all causes. A Phase I SAMA to replace the solenoids and air operators of the main steam isolation valves (MSIVs) to enhance reliability of the MSIVs has been implemented. Phase II SAMA 025, to improve the MSIV design to reduce the frequency of the initiator, was evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
EDG-ENG-FR-DG22R	1.55E-02	1.09	Diesel generator 22 fails to run	This term represents failure of EDG 22 to continue to run. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
AFW-TDP-FS-TDP22	4.18E-03	1.078	AFW turbine-driven pump 22 fails to start on demand	This term represents failure of AFW turbine-driven pump 22 to start on demand. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
EDG-ENG-FS-DG23S	5.71E-03	1.063	Diesel generator 23 fails to start	This term represents failure of EDG 23 to start on demand. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EDG-MAI-MA-EDG22	1.67E-02	1.062	Diesel generator 22 out for maintenance	This term represents EDG 22 out for maintenance. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
IE-TC15SW1	3.42E-05	1.059	Rupture of 3 inch service water line in the control building switchgear room flood zone CB 15-1	This term represents an internal flooding event due to rupture of a 3 inch service water line in control building switchgear room flood zone CB 15-1. Phase II SAMAs 054, 062 and 065, providing a flood alarm, providing a hard-wired connection to a SI pump from an ASSS power supply, and upgrading the ASSS to allow timely restoration of seal injection and cooling, were evaluated.
C	1.57E-05	1.057	Reactor protection system failure	This term represents failure of the reactor protection system. Improvements to minimize the risk associated with ATWS scenarios, including enhancement of operator training for ATWS and installation of an ATWS mitigating system actuation circuitry (AMSAC) system, have already been implemented. Phase II SAMAs 047, 048, 049, and 050, adding an independent boron injection system, adding relief valves to prevent equipment damage from pressure spikes, installing motor generator set trip breakers in the control room, and providing capability to remove power from the bus powering the control rods, were evaluated.
IE-T2	3.86E-01	1.051	Loss of main feedwater initiator	This term represents an initiating event caused by loss of feedwater. Industry efforts over the last twenty years have led to a significant reduction of plant scrams from all causes. Phase II SAMAs 041 and 043, to install a digital feedwater upgrade and to add a motor-driven feedwater pump, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
OAFWT	6.97E-03	1.051	Failure to manually control turbine-driven AFW pump 22 after battery depletion	This term represents operator failure to control turbine-driven AFW pump 22 after battery depletion, leading to unavailability of AFW turbine-driven pump 22 to provide water to the steam generators. Phase I SAMAs to improve operator response, install pneumatic pressure and level indications, and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. In addition, Phase II SAMAs 029, 043 and 044, improving DC load shedding, adding an additional motor-driven pump, and installing a fire water backup supply to the steam generators, were evaluated.
IE-TC15FP2	2.78E-05	1.048	Rupture of 4 inch fire protection line in the control building stairwell elevation 53-feet flood zone CB 53-1	This term represents an internal flooding event due to rupture of a 4 inch fire protection line in control building stairwell flood zone CB 53-1. Phase I SAMAs have been implemented to improve procedures to reduce CDF contributions due to internal flooding. Phase II SAMAs 054, 062 and 065, providing a flood alarm, providing protection against flood propagation from the stairwell to the switchgear room, and providing a hard-wired connection to a SI pump from an ASSS power supply, were evaluated.
MWS-XHE-FO-CVCS	2.72E-02	1.047	Failure to align backup city water cooling to charging pumps	This term represents operator failure to align city water to the charging pumps for reactor coolant pump (RCP) seal cooling during transients. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 67, providing hardware connections to allow the primary water system to be used to cool charging pumps to mitigate the impact of this event, was evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
AFW-TDP-FR-TDP22	2.34E-03	1.042	AFW turbine-driven pump 22 fails to continue to run	This term represents failure of AFW turbine-driven pump 22 to continue to run. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
IE-T7	7.03E-03	1.042	SGTR initiator	This term represents a SGTR initiating event. Many Phase I SAMAs have been implemented to mitigate this event including improving detection and isolation capabilities, improving makeup capabilities to the reactor pressure vessel, improving primary side depressurization reliability, improving secondary side heat removal capability, and enhancing training. Phase II SAMAs 018, 019, and 020, installing a highly reliable steam generator shell side heat removal system, increasing secondary side pressure capacity such that a SGTR would not cause the relief valve to lift, and routing the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove the fission products to mitigate the impact of this event, were evaluated.
AFW-CBR-OO-52AF1	6.58E-03	1.038	AFW motor-driven pump 21 circuit breaker 52/AF1 does not operate	This term represents failure of AFW motor-driven pump 21 circuit breaker 52/AF1 to operate on demand, causing unavailability of the pump. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
AC0-RCK-NO-MDBK4	2.50E-03	1.037	Failure of mode switch BK-4 control circuit	This term represents failure of mode switch BK-4 control circuit, causing loss of offsite power. Phase I SAMAs for coping with SBO events, including cross-tying diesel fuel oil supply lines, cross-tying AC and DC buses, and adding additional diesel generators, have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
IE-TCCW	1.05E-03	1.035	Loss of component cooling water initiator	This term represents the loss of component cooling water (CCW) initiating event. Many Phase I SAMAs have been implemented to mitigate this event including providing more reliable or diverse high or low pressure injection cooling, improving RCP seal cooling systems, and enhancing procedures for coping with loss of CCW. Phase II SAMAs 003, 005 and 064, to provide an additional CCW pump, to improve the ability to cool the residual heat removal (RHR) heat exchangers, and to provide a backup cooling water source for the CCW heat exchangers, were evaluated.
IE-TT15	7.35E-03	1.034	Rupture of condenser water boxes and 84 inch circulating water piping in the turbine building elevation 15-feet flood zone TB 15-1	This term represents an internal flooding event due to rupture of condenser water boxes and 84 inch circulating water piping in turbine building flood zone TB 15-1. This event causes damage to the 6.9kV switchgear. A Phase I SAMA has been implemented to improve inspection of circulating water system expansion joints to reduce the CDF contribution from this event. Phase II SAMAs 062 and 065, providing a hard-wired connection to a SI pump from an ASSS power supply and upgrading the ASSS power supply, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
EDG-CCF-FR-DG223	2.25E-04	1.031	Common cause failure of diesel generators 22 & 23 fail to run	This term represents common cause failure of diesel generators 22 & 23 to continue to run. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EDG-ENG-FS-DG22S	5.71E-03	1.031	Diesel generator 22 fails to start	This term represents failure of EDG 22 to start on demand. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
AFW-FCV-CC-F406A	5.78E-03	1.03	AFW motor-driven pump 21 FCV-406A fails to open	This term represents failure of AFW motor-driven pump 21 flow control valve FCV-406A to open, causing unavailability of the pump. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
AFW-FCV-CC-F406B	5.78E-03	1.03	AFW motor-driven pump 21 FCV-406B fails to open	This term represents failure of AFW motor-driven pump 21 flow control valve FCV-406B to open, causing unavailability of the pump. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
MRI	1.23E-01	1.027	Failure of manual rod insertion during ATWS	This term represents operator failure to insert control rods during an ATWS event. Improvements to minimize the risk associated with ATWS scenarios, including enhancement of operator training for ATWS and installation of an AMSAC system, have already been implemented. Phase II SAMAs 047, 048, 049, and 050, adding an independent boron injection system, adding relief valves to prevent equipment damage from pressure spikes, installing motor generator set trip breakers in the control room, and providing capability to remove power from the bus powering the control rods, were evaluated.
AFW-MDP-FS-PM21	4.60E-03	1.027	AFW motor-driven pump 21 fails to start on demand	This term represents failure of AFW motor-driven pump 21 to start on demand. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
CVC-MAI-MA-PM23	1.56E-02	1.025	Charging pump 23 out for testing and maintenance	This term represents charging pump 23 out for testing and maintenance, causing loss of RCP seal cooling and emergency boration. Phase II SAMAs 001 and 002, providing an independent RCP seal injection system with and without a dedicated diesel, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
AC4-CCF-HW-480VS	2.15E-07	1.024	Common cause failure of 480V switchgears 21& 22	This term represents common cause failure of 480V switchgears 21& 22. Phase I SAMAs to improve the availability of the AC bus and coping with SBO events, including cross-tying and repairing or replacing circuit breakers, cross-tying diesel fuel oil supply lines, cross-tying AC and DC buses, and adding additional onsite power sources, have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
OASSS-HHI	1.58E-02	1.023	Failure to align SI pump to ASSS (192 gpm total RCP seal leak rate)	This term represents operator failure to align a SI pump to its ASSS power supply to mitigate a RCP seal LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 062 to provide a hard-wired connection to a SI pump from ASSS was evaluated.
IE-S2	5.00E-04	1.022	Small break LOCA initiator	This term represents the small LOCA initiating event. Phase I SAMAs improving emergency core cooling system (ECCS) sump strainer availability and emphasizing timely recirculation alignment in operator training have been implemented to mitigate this event. Phase II SAMAs 035, 036, 037, 039, 040, 055, 056, 058, and 068 to enhance high and low pressure injection and recirculation systems, and provide an independent source of cooling for the recirculation pump motors to reduce the CDF contribution from small break LOCA, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
ORCS-L	2.17E-04	1.022	Failure to perform late RCS cooldown & depressurization during SGTR	This term represents operator failure to perform late cooling and depressurization to cold shutdown following a SGTR to terminate leakage from the reactor coolant system (RCS) into the secondary prior to depleting refueling water storage tank (RWST) inventory. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 018, 019, and 020, installing a highly reliable steam generator shell side heat removal system, increasing secondary side pressure capacity such that a SGTR would not cause the relief valve to lift, and routing the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove the fission products to mitigate the impact of this event, were evaluated.
OLHIR-S2	5.74E-04	1.021	Failure to initiate low-head internal recirculation during small LOCA	This term represents operator failure to align low-head ECCS internal recirculation following the injection phase of ECCS to deliver flow to RCS cold legs during a small LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 036, to create an automatic swap-over to recirculation on low RWST level, was evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
OLHER-S2	1.01E-03	1.021	Failure to initiate low-head external recirculation during small LOCA	This term represents operator failure to align low-head ECCS external recirculation following the injection phase of ECCS to deliver flow to RCS cold legs during a small LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 036, to create an automatic swap-over to recirculation on low RWST level, was evaluated.
IE-RCPSL	2.50E-03	1.019	RCP seal LOCA initiator	This term represents the RCP seal LOCA initiating event. Phase I SAMAs improving ECCS sump strainer availability and emphasizing timely recirculation alignment in operator training have been implemented to mitigate this event. Phase II SAMAs 035, 036, 037, 038, 040, 055, 056, 058, and 068, to enhance high and low pressure injection and recirculation systems and to provide an independent source of cooling for the recirculation pump motors, were evaluated.
CVC-XHE-FO-BORAT	1.50E-02	1.018	Failure to initiate emergency boration during ATWS	This term represents operator failure to initiate emergency boration during ATWS. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 047, 048, 049, and 050, adding an independent boron injection system, adding relief valves to prevent equipment damage from pressure spikes, installing motor generator set trip breakers in the control room, and providing capability to remove power from the bus powering the control rods, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
IE-TSWN	6.86E-04	1.018	Loss of non-essential service water system initiator	This term represents the loss of non-essential service water initiating event. Phase I SAMAs have been implemented to improve service water system reliability by providing additional service water pumps, enhancing screen wash, and replacing strainers. Phase II SAMAs 004 and 064, to provide procedural guidance to cross-tie service water pumps and provide backup cooling water for the CCW heat exchangers, were evaluated.
EDG-ENG-FR-DG21R	1.55E-02	1.018	Diesel generator 21 fails to run	This term represents failure of EDG 21 to continue to run. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
AFW-MAI-MA-PM21	4.02E-03	1.017	AFW motor-driven pump 21 out for testing and maintenance	This term represents AFW motor-driven pump 21 out for testing and maintenance. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
ORCS-E	2.56E-02	1.017	Failure to perform early RCS cooldown & depressurization during SGTR	This term represents operator failure to perform early cooling and depressurization to cold shutdown following a SGTR to terminate leakage from the RCS into the secondary prior to depleting RWST inventory. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 018, 019, and 020, installing a highly reliable steam generator shell side heat removal system, increasing secondary side pressure capacity such that a SGTR would not cause the relief valve to lift, and routing the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove the fission products to mitigate the impact of this event, were evaluated.
CWBKUP	7.27E-03	1.016	Failure to align backup city water cooling to RHR and SI pumps	This term represents operator failure to align city water to the RHR and safety injection (SI) pumps to prevent and mitigate LOCAs. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. No Phase II SAMAs were recommended for this subject.
PWS-XHE-FO-RHR1	1.20E-02	1.016	Failure to align primary water backup cooling to RHR and SI pumps	This term represents operator failure to align primary water to the RHR and SI pumps to prevent and mitigate LOCAs. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. No Phase II SAMAs were recommended for this subject.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
IE-TPFPCR	2.60E-05	1.014	Rupture of the fire protection piping in PAB 80-feet elevation flood zone PAB 80-1 impacting CCW & RHR pumps	This term represents an internal flooding event due to rupture of fire protection piping in primary auxiliary building (PAB) flood zone PAB 80-1 impacting CCW and RHR pumps. Phase I SAMAs have been implemented to improve procedures to reduce CDF contribution due to internal flooding. Phase II SAMA 063, providing a water-tight door for additional protection of the RHR pumps against the flooding event, was evaluated.
AFW-RCK-NO-PM21	2.50E-03	1.014	AFW motor-driven pump 21 control circuit no output	This term represents failure of AFW motor-driven pump 21 control circuit causing unavailability of the pump. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
SWS-CCF-FR-ALL	2.03E-06	1.014	Common cause failure of all 6 service water pumps to run	This term represents common cause failure of all 6 service water pumps to run, leading to loss of service water cooling to supported components. Phase I SAMAs were implemented to improve service water system reliability by providing additional service water pumps, enhancing screen wash, and replacing strainers. Phase II SAMAs 031, 032 and 063, provide a backup source for diesel cooling, use the fire protection system as a backup source for diesel cooling, and provide backup cooling water for the CCW heat exchangers, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
PPR-AOV-OO-455C	8.53E-04	1.013	PORV PCV-455C fails to re-close	This term represents failure of pressure-operated relief valve (PORV) PCV-455C to re-close, causing a small LOCA. Phase I SAMAs improving ECCS sump strainer availability and emphasizing timely recirculation alignment in operator training have been implemented to mitigate this event. Phase II SAMAs 035, 036, 037, 039, 040, 055, 056, 058, and 068 to enhance high and low pressure injection and recirculation systems, and providing independent source of cooling for the recirculation pump motors, to reduce the CDF contribution from stuck open PORV induced small LOCA, were evaluated.
CCW-XHE-FO-RCPSL	1.19E-02	1.013	Failure to manually restart CCW pumps given inadvertent trip	This term represents operator failure to manually restart CCW pumps, leading to seal LOCA. Phase I SAMAs, providing more reliable or diverse high or low pressure injection cooling, providing additional RCP seal cooling, and enhancing loss of CCW procedures, have been implemented to mitigate this event. Phase II SAMAs 005 and 064, improving the ability to cool the RHR heat exchangers and providing a backup cooling water source for the CCW heat exchangers, were evaluated.
PPR-AOV-OO-456	8.53E-04	1.013	PORV PCV-456 fails to re-close	This term represents failure of PORV PCV-456 to re-close, causing a small LOCA. Phase I SAMAs improving ECCS sump strainer availability and emphasizing timely recirculation alignment in operator training have been implemented to mitigate this event. Phase II SAMAs 035, 036, 037, 039, 040, 055, 056, 058, and 068 to enhance high and low pressure injection and recirculation systems, and providing independent source of cooling for the recirculation pump motors, to reduce the CDF contribution from stuck open PORV induced small LOCA, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
OHHER-S2	1.45E-03	1.013	Failure to align high-head external recirculation during small LOCA	This term represents operator failure to align high-head ECCS external recirculation following the injection phase of ECCS to deliver flow to RCS cold legs during a small LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 036, to create an automatic swap-over to recirculation on low RWST level, was evaluated.
EDG-MAI-MA-EDG21	1.45E-02	1.012	Diesel generator 21 out for maintenance	This term represents EDG 21 out for maintenance. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
EDG-CCF-FR-3EDGS	3.27E-04	1.012	Common cause failure of 3 diesel generators to continue to run	This term represents common cause failure of three diesel generators to continue to run. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
AFW-CCF-FS-AFWPM	5.75E-04	1.011	Common cause failure of AFW motor-driven pumps 21 and 23 to start	This term represents common cause failure of AFW motor-driven pumps 21and 23 to start. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
EDG-CCF-FS-DG223	8.37E-05	1.011	Common cause failure of diesel generators 22 & 23 to start	This term represents common cause failure of diesel generators 22 & 23 to start on demand. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
HHI-CBR-OO-1T	6.72E-03	1.011	SI pump 21 circuit breaker 52/SI1 does not operate	This term represents failure of SI pump 21 circuit breaker 52/SI1 to operate on demand, causing unavailability of the pump following an SBO. Phase II SAMAs 035, 037 and 039, providing an additional high pressure injection pump with independent diesel, providing injection via the diesel driven fire pump, and adding diesel engines to some high pressure injection pumps, were evaluated.
AFW-XHE-RE-AFW22	6.49E-04	1.011	Failure to restore AFW turbine-driven pump 22 path components after maintenance	This term represents failure to restore AFW turbine-driven pump 22 after testing and maintenance. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
IE-S3	3.40E-03	1.01	Small-small break LOCA initiator	This term represents the small-small LOCA initiating event. Phase I SAMAs improving ECCS sump strainer availability and emphasizing timely recirculation alignment in operator training have been implemented to mitigate this event. Phase II SAMAs 035, 036, 037, 039, 040, 055, 056, 058, and 068 to enhance high and low pressure injection and recirculation systems, and provide an independent source of cooling for the recirculation pump motors, to reduce the CDF contribution from small-small LOCA, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
CVC-CBR-OO-1M	6.52E-03	1.01	Charging pump 23 circuit breaker 1M on panel 12FD3 does not operate	This term represents failure of charging pump 23 circuit breaker1M on panel 12FD3 to operate, causing loss of ASSS supply to the charging pump. Phase II SAMAs 001, 002, 065, providing an independent RCP seal injection system with and without a dedicated diesel, and upgrading the ASSS to allow timely restoration of seal injection and cooling, were evaluated.
HHI-MDP-FS-SI21	5.60E-03	1.009	SI pump 21 fails to start on demand	This term represents failure of SI pump 21 to start on demand, causing unavailability of the pump to mitigate a seal LOCA and to perform the feed and bleed function during transients. Phase II SAMAs 035, 037 and 039, providing an additional high pressure injection pump with independent diesel, providing injection via the diesel-driven fire pump, and adding diesel engines to some high pressure injection pumps, were evaluated.
LHI-CCF-CC-7467	2.48E-05	1.009	Common cause failure of MOV 746 & 747 to open	This term represents common cause failure of motor-operated valves (MOVs) 746&747 to open, causing loss of the low-head injection and recirculation paths during LOCAs and transients. Phase II SAMAs 055 and 056, allowing high-head recirculation from either RHR heat exchanger and keeping the valves normally open were evaluated.
MSS-CCF-CC-4ADVS	2.18E-05	1.009	Common cause failure of all four steam generators' atmospheric dump valves to open	This term represents common cause failure of all four steam generators' atmospheric dump valves to open during a SGTR event. Phase II SAMAs 018 and 020, to install a steam generator shell side heat removal system and to install a water spray over the steam generator safety valves, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
AFW-CCF-CC-3149	1.14E-05	1.009	Common cause failure of check valves BFD-31, 34 & 39	This term represents common cause failure of check valves BFD-31, 34 and 39, leading to failure of all AFW pumps to deliver sufficient flow to the steam generators. Phase II SAMAs 043, 044, 45 and 57 adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, replacing PORVs with larger ones and providing DC power backup for the PORVs, were evaluated.
IE-TPNESW	1.58E-05	1.009	Rupture of the non-essential service water line in the PAB 80-feet elevation	This term represents an internal flooding event due to rupture of the non-essential service water line in the PAB 80-feet elevation, resulting in loss of cooling water to CCW and RHR heat exchangers, charging pumps and RCP seals. Phase I SAMAs have been implemented to improve procedures to reduce CDF contribution due to internal flooding. Phase II SAMAs 005 and 064, improving the ability to cool the RHR heat exchangers and providing a backup cooling source for the CCW heat exchangers, were evaluated.
OASSS-CHG	5.17E-03	1.008	Failure to align charging pump to ASSS	This term represents operator failure to align a charging pump to its ASSS power supply to mitigate a RCP seal LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 001, 002, and 065, providing an independent RCP seal injection system with and without a dedicated diesel, and upgrading the ASSS to allow timely restoration of seal injection and cooling, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
MSS-XHE-FO-SGISO	1.86E-02	1.008	Failure to perform early isolation of ruptured steam generator during SGTR	This term represents operator failure to isolate the ruptured steam generator early during a SGTR event. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 018, 019, and 020, installing a highly reliable steam generator shell side heat removal system, increasing secondary side pressure capacity such that a SGTR would not cause the relief valve to lift, and routing the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove the fission products to mitigate the impact of this event, were evaluated.
ODEP-LCCW	4.21E-02	1.007	Failure to perform rapid depressurization of RCS for low-head injection during loss of CCW	This term represents operator failure to depressurize the RCS for low-head injection following loss of CCW and failure of high-head SI. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 040 and 045, to enhance the reactor coolant depressurization system and replace PORVs with larger ones, were evaluated.
CVC-PDP-FS-PM23	4.57E-03	1.007	Charging pump 23 fails to start on demand	This term represents failure of charging pump 23 to start on demand, causing loss of RCP seal cooling and emergency boration. Phase II SAMAs 001, 002, 047, and 067, providing an independent RCP seal injection system with and without a dedicated diesel, providing an independent boron injection system, and adding a hardware connection to allow primary water to cool the charging pumps, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
ODEPR-TC	4.80E-03	1.007	Failure to perform RCS cooldown & depressurization during 480V switchgear room flood	This term represents operator failure to perform RCS cooldown and depressurization during a 480V switchgear room flood to terminate leakage from RCS into the secondary prior to depleting RWST inventory. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 040 and 045, to enhance the reactor coolant depressurization system and replace PORVs with larger ones, were evaluated.
AFW-CBR-OO-52AF3	6.58E-03	1.007	AFW motor-driven pump 23 circuit breaker 52/AF1 does not operate	This term represents failure of AFW motor-driven pump 23 circuit breaker 52/AF3 to operate on demand, causing unavailability of the pump. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
IE-S1	4.00E-05	1.007	Intermediate break LOCA initiator	This term represents the intermediate LOCA initiating event. Phase I SAMAs improving ECCS sump strainer availability and emphasizing timely recirculation alignment in operator training have been implemented to mitigate this event. Phase II SAMAs 035, 036, 037, 039, 040, 055, 056, 058, and 068 to enhance high and low pressure injection and recirculation systems and provide an independent source of cooling for the recirculation pump motors, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
AFW-XHE-RE-AFW21	1.15E-03	1.006	Failure to restore AFW motor-driven pump 21 path components after testing and maintenance	This term represents failure to restore AFW motor-driven pump 21 after testing and maintenance. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
EDG-ENG-FS-DG21S	5.71E-03	1.006	Diesel generator 21 fails to start	This term represents failure of EDG 21 to start on demand. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
AFW-XHE-FO-HC405	2.26E-04	1.006	Failure to align AFW turbine-driven pump 22	This term represents operator failure to align AFW turbine-driven pump 22, leading to unavailability of the pump to provide water to the steam generator. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. In addition, Phase II SAMA 043, adding an additional motor-driven pump, was evaluated.
DC1-CCF-HW-2122B	1.05E-06	1.006	Common cause failure of DC batteries 21 & 22	This term represents common cause failure of DC batteries 21 & 22. Phase II SAMAs 026, 027, 028, and 029, for enhancing DC system availability and reliability, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
OHHIR-S1	2.50E-03	1.006	Failure to align high-head internal recirculation during medium LOCA	This term represents operator failure to align high-head ECCS internal recirculation following the injection phase of ECCS to deliver flow to RCS cold legs during a medium LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 036, to create an automatic swap-over to recirculation on low RWST level, was evaluated.
IE-R	1.00E-07	1.006	Catastrophic reactor vessel rupture	This term represents an initiating event caused by reactor vessel rupture. Phase II SAMAs 012 and 016, using fire protection system as a backup source for containment spray system, and providing redundant containment spray systems to mitigate the consequence of a reactor vessel rupture, were evaluated.
OHHER-S1	4.19E-03	1.006	Failure to align high-head external recirculation during medium LOCA	This term represents operator failure to align high-head ECCS external recirculation following the injection phase of ECCS to deliver flow to RCS cold legs during a medium LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 036, to create an automatic swap-over to recirculation on low RWST level, was evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
CDS-XHE-FO-CDPM	3.01E-02	1.006	Failure to align condensate for secondary heat removal	This term represents operator failure to align the condensate system for secondary heat removal during transients. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMA 044, using the fire water system as backup for steam generator inventory, was evaluated.
LHI-RCK-NO-746	2.50E-03	1.005	MOV 746 control circuit no output	This term represents control circuit failure of MOV 746, causing one of the low-head injection and recirculation paths to be unavailable during LOCAs and transients. Phase II SAMA 056, keeping the valve normally open to improve availability of low-head injection and recirculation modes of operation, was evaluated.
LHI-RCK-NO-747	2.50E-03	1.005	MOV 747 control circuit no output	This term represents control circuit failure of MOV 747, causing one of the low-head injection and recirculation paths to be unavailable during LOCAs and transients. Phase II SAMA 056, keeping the valve normally open to improve availability of low-head injection and recirculation modes of operation, was evaluated.
ODEP-S2	4.21E-02	1.005	Failure to rapidly depressurize RCS for low-head injection during small LOCA	This term represents operator failure to depressurize the RCS for low-head injection during a small break LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 040 and 045, to enhance the reactor coolant depressurization system and replace PORVs with larger ones, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
AC4-CBR-CC-52-6A	5.00E-04	1.005	480V circuit breaker 52/6A fails to trip on demand	This term represents failure of 480V circuit breaker 52/6A to trip on demand, causing unavailability of the 480Vbus 6A power supply. Phase I SAMAs to improve the availability of the AC bus by cross-tying and repairing or replacing circuit breakers have already been implemented. Phase II SAMA 030, creating AC power cross-tie capability with the other unit, was evaluated.
AC4-CBR-OO-52EG3	5.00E-04	1.005	480V circuit breaker 52/EG3 fails to close	This term represents failure of 480V circuit breaker 52/EG3 to close on demand, causing unavailability of the EDG power supply to 480Vbus 6A. Phase I SAMAs to improve the availability of the AC bus by cross-tying and repairing or replacing circuit breakers have already been implemented. Phase II SAMA 030, creating AC power cross-tie capability with the other unit, was evaluated.
AFW-ORF-PG-TDP22	3.00E-04	1.005	AFW turbine-driven pump 22 min-flow break down orifice plugged	This term represents plugging of the AFW turbine-driven pump 22 min-flow break down orifice, causing unavailability of the pump. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.
RHR-CCF-CO-2MOVS	4.47E-06	1.005	Common cause failure of 2 MOVs fails to remain closed	This term represents common cause failure of 2 MOVs to remain closed in the RCS shutdown cooling line, causing an ISLOCA event. Phase II SAMA 021, providing additional pressure or leak monitoring instrumentation for ISLOCAs to decrease ISLOCA frequency, was evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
EDG-CCF-FS-3EDGS	1.36E-04	1.005	Common cause failure of diesel generators 21, 22 & 23 fail to start	This term represents common cause failure of diesel generators 21, 22 & 23 to start on demand. Phase II SAMAs 026, 027, 028, 029, 030, 031, 032, 033, and 066, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
DGV-CCF-FS-FAN	1.33E-04	1.005	Common cause failure of 4/6 EDG ventilation fans to start	This term represents common cause failure of 4 out of 6 diesel generator ventilation fans to start on demand, eventually causing the loss of 2 out 3 diesel generators. Phase II SAMA 006, adding a diesel generator building high temperature alarm, was evaluated.
RHR-MOV-RP-746	9.00E-03	1.005	RHR heat exchanger 22 outlet MOV 746 rupture	This term represents RHR heat exchanger 22 outlet MOV 746 rupture, causing an ISLOCA event. Phase II SAMAs 021 and 023, providing additional pressure or leak monitoring instrumentation for ISLOCAs and increasing valve leak testing to decrease ISLOCA frequency, were evaluated.
RHR-MOV-RP-747	9.00E-03	1.005	RHR heat exchanger 22 outlet MOV 747 rupture	This term represents RHR heat exchanger 21 outlet MOV 747 rupture, causing an ISLOCA event. Phase II SAMAs 021 and 023, providing additional pressure or leak monitoring instrumentation for ISLOCAs and increasing valve leak testing to decrease ISLOCA frequency, were evaluated.
AFW-MDP-FS-PM23	4.60E-03	1.005	AFW motor-driven pump 23 fails to start on demand	This term represents failure of AFW motor-driven pump 23 to start on demand. Phase II SAMAs 043 and 044, adding an additional motor-driven pump to enhance AFW system reliability and installing a fire water backup supply to the steam generators, were evaluated.

Table E.1-2
Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Description	Disposition
SWS-XHE-RE-29/30	1.30E-04	1.005	Failure to properly align SWN-29/ SWN-30 during header swap	This term represents operator failure to properly align SWN-29/SWN-30 during header swap, leading to loss of service water cooling to the EDGs. Phase II SAMAs 031 and 032, providing backup cooling water for the EDGs, were evaluated.
IE-TPESW	2.07E-05	1.005	Rupture of the essential service water line in the PAB 98-feet elevation	This term represents an internal flooding event due to rupture of an essential service water line in the PAB 98-feet elevation, resulting in loss of EDG jacket cooling and containment cooling. Phase I SAMAs have been implemented to improve procedures to reduce CDF contribution due to internal flooding. Phase II SAMAs 005, 016, 031, 032, 062, 064, and 065, providing a redundant containment spray system, providing backup sources for EDG cooling, improving the ability to cool the RHR heat exchangers, providing a hard-wired connection to an SI pump from an ASSS power supply, providing backup cooling to the CCW heat exchangers, and upgrading the ASSS power supply, were evaluated.

CDF Uncertainty

The uncertainty associated with CDF was estimated using Monte Carlo techniques implemented in CAFTA for the base case mode. The results are shown in Table E.1-3.

Table E.1-3
CDF Uncertainty

Confidence	CDF (/ry)
Mean value	1.89E-5
5^{th} percentile	8.73E-6
50^{th} percentile	1.52E-5
95^{th} percentile	3.96E-5

The values in Table E.1-3 reflect the uncertainties associated with the data distributions used in the analysis. The ratio of the 95th percentile to the mean is about 2.10. This uncertainty factor is included in the factor of 8 used to determine the "baseline benefit with uncertainty" described in Section 4.21.5.4.

E.1.2 PSA Model - Level 2 Analysis

E.1.2.1 Containment Performance Analysis

The IP2 Level 2 PSA model used for the SAMA analysis is the most recent internal events risk model, which is an updated version of the model used in the IPE [Reference E.1-1]. The Level 2 PSA model used for the SAMA analysis, Revision 1 [Reference E.1-3] reflects the IP2 operating configuration and design changes as of December 2005.

The IP2 Level 2 model includes two types of considerations: (1) a deterministic analysis of the physical processes for a spectrum of severe accident progressions, and (2) a probabilistic analysis component in which the likelihood of the various outcomes are assessed. The deterministic analysis examines the response of the containment to the physical processes during a severe accident. This response is performed by

- utilization of the Modular Accident Analysis Program (MAAP) code [Reference E.1-4] to simulate severe accidents that have been identified as dominant contributors to core damage in the Level 1 analysis, and

- reference MAAP calculations of several hydrodynamic and heat transfer phenomena that occur during the progression of severe accidents. Examples include debris coolability, pressure spikes due to ex-vessel steam explosions, scoping calculation of direct containment heating (DCH), molten debris filling the reactor pit, containment bypass, deflagration and detonation of hydrogen, thrust forces at reactor vessel failure, and thermal attack of containment penetrations.

The Level 2 analysis examined the dominant accident sequences and the resulting plant damage states (PDS) defined in Level 1. The Level 1 analysis involves the assessment of those scenarios that could lead to core damage.

A full Level 2 model was developed for the IP2 PSA and completed at the same time as the Level 1 model. The Level 2 model consists of a single containment event tree (CET) with functional nodes that represent phenomenological events and containment protection system status. The nodes were quantified using subordinate trees and logic rules. A list of the CET functional nodes and descriptions, used for the Level 2 analysis is presented in Table E.1-4.

The Large Early Release Frequency (LERF) is an indicator of containment performance from the Level 2 results because the magnitude and timing of these releases provide the greatest potential for early health effects to the public. The frequency calculated is approximately 6.50E-7/ry [Reference E.1-3]. Figure E.1-1 and Figure E.1-2 summarize the Level 2 results. Radionuclide release categories are described in Section E.1.2.2.3.

LERF represents a small fraction (~4%) of all release end states. Three types of accidents dominate the internal large early release: accidents initiated by SGTRs, ISLOCAs, and accidents initiated by internal floods impacting vital power buses. (Internal floods impacting vital power buses contribute to LERF because they result in SBO and core damage without power available to the 480 VAC safeguard buses for the duration of the event. A large release occurs due to early containment rupture at vessel breach from either containment overpressurization or hydrogen burns.)

Table E.1-5 provides a correlation between the Level 2 RRW risk significant events (severe accident phenomenon, initiating events, component failures and operator actions) identified from the current IP2 PSA LERF model [Reference E.1-3] and the SAMAs evaluated in Section E.2.

Table E.1-4
Notation and Definitions for IP2 CET Functional Nodes

CET Node	CET Functional Node Description
Plant Damage State Event (PDS_EVNT)	This top event represents the initiators considered in the containment performance analysis.
RCS Pressure at Vessel Failure (RCS@VF)	This top event identifies the status of the RCS pressure. RCS@VF is set to success when RCS pressure is low. RCS@VF is set to failure when RCS pressure is high.

Table E.1-4
Notation and Definitions for IP2 CET Functional Nodes
(Continued)

CET Node	CET Functional Node Description
In-vessel Cooling Recovery (IN-REC)	This top event addresses the recovery of coolant injection into the vessel after core degradation but prior to vessel breach. This top event considers the possibility of low-pressure injection systems working once the RCS is depressurized.
Vessel Failure (VF)	This top event addresses recovery from core degradation within the vessel and the prevention of vessel head thermal attack. Core melt recovery requires the recovery of core cooling prior to core blocking or relocation of molten debris to the lower plenum and thermal attack of the vessel head.
Early Containment Failure (CFE)	This top event node considers the potential loss of containment integrity at, or before, vessel failure. Several phenomena are considered credible mechanisms for early containment failure. They may occur alone or in combination. The phenomena are containment isolation failure; containment bypass; containment overpressure failure at vessel breach; hydrogen deflagration or detonation; fuel-coolant interactions (steam explosions); and high pressure melt ejection (HPME) with subsequent DCH.
Debris Cooled Ex-vessel (DCOOL)	This top event considers the delivery of water to the reactor pit (sump), via containment sprays, or via injection to the vessel and drainage out a vessel breach into the reactor pit/sump area. Success implies the availability of water and the formation of a coolable debris bed such that concrete attack is precluded. Failure implies that the molten core attacks concrete in the reactor pit, that core debris remains hot, and sparing of the concrete decomposition products through the melt releases the less volatile fission products to the containment atmosphere.
Late Containment Failure (CFL)	This top event addresses the potential loss of containment integrity in the long-term. Late containment failure may result from base mat melt-through or from long-term steam and non-condensable gas generation from the attack of molten core debris on concrete.
Fission Product Removal (FPR)	This top event addresses fission product releases from the fuel into the containment and airborne fission product removal mechanisms within the containment structure to characterize potential magnitude of fission product releases to the environment should the containment fail. Failure implies that most of the fission products from the fuel and containment are ultimately released to the environment without mitigation.

Table E.1-4
Notation and Definitions for IP2 CET Functional Nodes
(Continued)

CET Node	CET Functional Node Description
Containment Failure Mode (CFM)	This top event is used to characterize the impact of the timing of containment failure and the break size on the duration and mitigation of the fission product source terms.

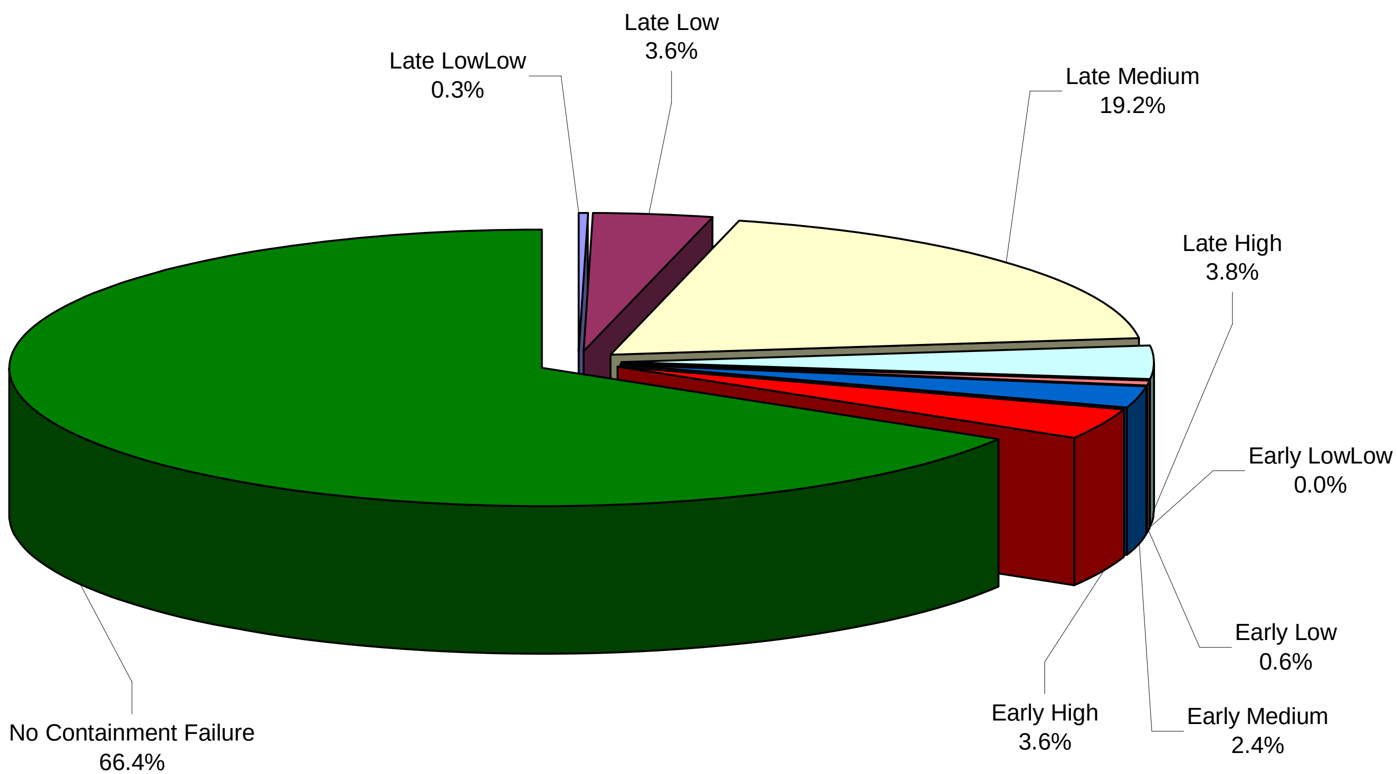

Figure E.1-1
IP2 Radionuclide Release Category Summary

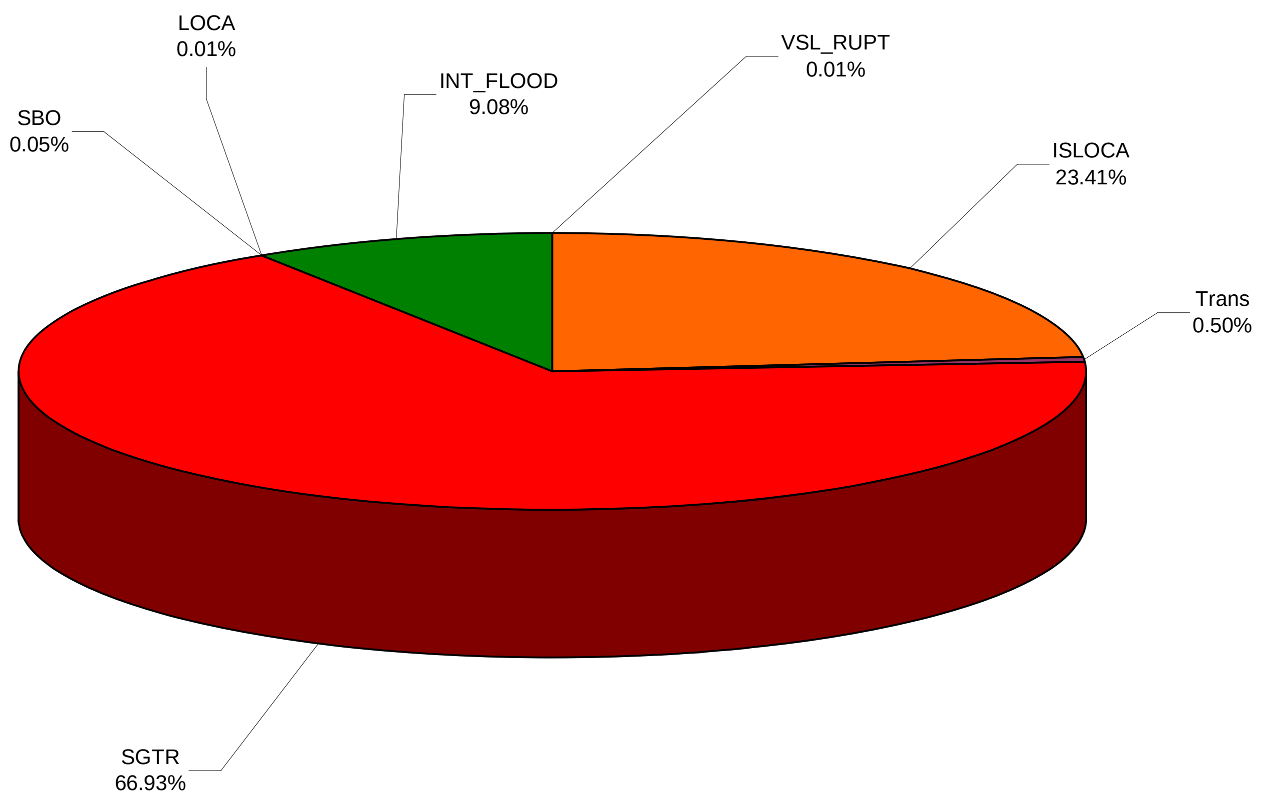

Figure E.1-2
IP2 Contributions to Large Early Release Frequency

Table E.1-5
IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
NO-FPR_BYPASS	1.0	10.198	No fission product removal due to containment bypass event	This term represents the probability that fission product removal does not occur because containment is bypassed by either an ISLOCA or a SGTR with a stuck-open relief valve. Phase II SAMAs 021, 022, 023, and 024, to install additional pressure or leak monitoring instrumentation, increase leak testing of ISLOCA valves, add redundant and diverse limit switches to containment isolation valves, and ensure ISLOCA releases are scrubbed, were evaluated. For SGTR sequences, numerous Phase I SAMAs have been implemented to increase reliability of the steam generator via enhanced maintenance practices, improved detection and isolation capabilities, improved makeup capabilities to the RCS, improved primary side depressurization reliability, improved secondary side heat removal capability, installation of new steam generators in 2000 and enhanced SGTR training. Phase II SAMAs 018, 019 and 020 were evaluated to mitigate SGTR events.

Table E.1-5
IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
PDS_FRAC-51	2.41E-02	2.940	Long-term SGTR with stuck-open safety relief valve	This term is the plant damage state split fraction for a long-term SGTR scenario involving failure to isolate the ruptured steam generator and subsequent stuck-open steam generator safety relief valve. Phase I SAMAs were implemented providing procedures to enhance the likelihood of success of operator action in response to SGTR accident conditions and increasing the reliability of the steam generator via enhanced maintenance practices. Phase II SAMAs 018, 019 and 020 were evaluated to mitigate SGTR events.
NO_SAG-2	1.0	2.629	RCS depressurization failure-post core melt	This term represents the probability that RCS depressurization as described in severe accident guideline SAG-2, "Depressurize the RCS," is not performed during a high pressure core melt accident. Phase II SAMAs 040, 045, 053, and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated. In addition, Phase II SAMA 029, to improve DC bus load shedding to extend DC power availability, was evaluated.

Table E.1-5
IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
NO_HLSL_1	0.9	2.600	RCS hot leg or pressurizer surge line remains intact during medium pressure accident scenario	This term represents the probability that either the RCS hot leg or pressurizer surge line remains intact during an accident in which the RCS system pressure is between 675 psig and 2235 psig. Phase II SAMAs 040, 045, 053,and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated.
DP-45	1.0	1.280	RCS pressure is low at vessel breach given a large ISLOCA event	This term represents the probability that RCS depressurization occurs during a short-term large-break ISLOCA outside containment. Phase II SAMAs 021, 022, 023, and 024, to install additional pressure or leak monitoring instrumentation, increase leak testing of ISLOCA valves, add redundant and diverse limit switches to containment isolation valves, and ensure ISLOCA releases are scrubbed, were evaluated.
PDS_FRAC-50	7.96E-03	1.280	Short-term large ISLOCA outside containment event	This term is the plant damage state split fraction for a short-term large-break ISLOCA outside containment. Phase II SAMAs 021, 022, 023, and 024, to install additional pressure or leak monitoring instrumentation, increase leak testing of ISLOCA valves, add redundant and diverse limit switches to containment isolation valves, and ensure ISLOCA releases are scrubbed, were evaluated.

Table E.1-5
IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
NO_SAG-4	1.0	1.108	Containment injection post core melt does not occur	This term represents the probability that injection into containment as described in SAG-4, "Inject Into Containment," is not performed to cool the lower head of the reactor vessel. Additional benefit of flooding the containment is that water will be available for ECCS recirculation and to flood core debris in the reactor pit area after vessel breach. Phase II SAMAs 008 and 009, to contain molten core debris in the reactor pit area and to create a reactor cavity flooding system, were evaluated.
AC_SBO_FLOOD	1.0	1.104	Internal flooding induced SBO event fails AC power supply	This flag event indicates that AC power to the normal offsite supply buses and vital AC safeguard buses is disabled following an internal flooding event that impacts the control building switchgear room at the 15-foot elevation. Phase II SAMAs 054, 060, 061, 062 and 065, to install a flood alarm in the 480VAC switchgear room, to provide added protection against flood propagation into the 480VAC switchgear room, to provide a hard-wired connection to a SI pump from the ASSS power supply, and to upgrade the ASSS to allow timely restoration of seal injection and cooling, were evaluated.
NO-INVESSEL-COOL	1.0	1.100	In-vessel cooling failure post-core damage	This flag event indicates that in-vessel cooling fails during a core melt progression. Phase II SAMAs 034, 035, 036, 037, 038, and 039, for enhancing reactor vessel injection during transients, small LOCA and SBO, were evaluated.

Table E.1-5
IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
NO_EXVESSEL-COOL	0.8	1.096	No ex-vessel cooling due to internal flooding event	This term represents failure of ex-vessel cooling following a flood in the control building switchgear room. Phase II SAMAs 008 and 009 were evaluated to consider the benefits of containing molten core debris in the reactor pit area or installing a reactor cavity flooding system. Phase II SAMAs 034, 035, 037, 038 and 039 to provide a diesel-driven pump for enhancing reactor vessel injection, and Phase II SAMAs 054, 060, 061, 062 and 065, to install a flood alarm in the 480VAC switchgear room, to provide added protection against flood propagation into the 480VAC switchgear room, to provide a hard-wired connection to a SI pump from the a ASSS power supply, and to upgrade the ASSS to allow timely restoration of seal injection and cooling, were evaluated.
SLUMP_3	0.1	1.089	Core slump probability given CM > 20% and no injection	This term represents the probability of core slump to the lower head as a large mass, given no in-vessel injection. Phase II SAMAs 034, 035, 036, 037, 038, and 039, for enhancing reactor vessel injection and recirculation cooling, were evaluated.
VF_SIZE_PEN	0.9	1.084	Vessel penetration failure occurs debris thermal attack	This term represents the probability of vessel failure due to a single lower head penetration failure. Phase II SAMA 009 was evaluated to consider the benefit of a reactor cavity flooding system with the potential to cool a molten core before it causes vessel failure.

Table E.1-5
IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
DCH_OCCURS	0.5	1.081	DCH occurs given HPME phenomena	This term represents the probability that DCH occurs following HPME. Phase II SAMAs 040, 045, 053, and 057 to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated. In addition, Phase II SAMA 017, to erect a barrier to provide enhanced protection of the containment shell from ejected core debris following a core melt scenario at high pressure, and SAMA 029, to improve DC bus load shedding to extend DC power availability, were evaluated.
HPME_1	0.5	1.079	HPME occurs at high RCS pressure	This term represents the probability that HPME occurs at high RCS pressure. Phase II SAMAs 040, 045, 053, and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated.
DP-46	0.1	1.071	RCS pressure is low at vessel breach given a long-term SGTR with stuck-open safety relief valve	This term represents the probability that RCS depressurization occurs during a long-term SGTR with a stuck-open safety relief valve. Phase II SAMAs 018 and 019 to provide shell side heat removal and increase secondary pressure capacity, were evaluated. In addition, Phase II SAMAs 040, 045, 053, and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated.

Table E.1-5
IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
PDS_FRAC-47	7.66E-02	1.062	Long-term internal flood induced SBO sequence at medium RCS pressure	This term is the PDS split fraction for a long-term internal flood event that entails failure of normal offsite supply buses, vital AC safeguard buses and the occurrence of a RCP seal LOCA with the AFW turbine-driven pump available. Phase II SAMAs 054, 060, 061, 062 and 065, to install a flood alarm in the 480VAC switchgear room, to provide added protection against flood propagation into the 480VAC switchgear room, to provide a hard-wired connection to a SI pump from the ASSS power supply, and to upgrade the ASSS to allow timely restoration of seal injection and cooling, were evaluated.
DP-42	0.975	1.071	RCS pressure is medium at vessel breach given a long-term internal flood induced SBO sequence at medium RCS pressure	This term represents the probability that RCS depressurization occurs during a long-term internal flood induced SBO sequence in which a RCP seal LOCA occurs with the AFW turbine-driven pump available. Phase II SAMAs 040, 045, 053, and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated.
ELK5-P42	0.859	1.059	Small containment failure during a long-term internal flood induced SBO sequence at medium RCS pressure	This term represents the probability that a small containment failure occurs following a long-term internal flood induced SBO sequence in which a RCP seal LOCA occurs with the AFW turbine-driven pump available. Phase II SAMAs 009, 010, 011, 012, 013, 014, 015, and 016 for enhancing containment integrity, were evaluated.

Table E.1-5
IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
H2_EARLY2_MED	0.5	1.058	In-vessel hydrogen production is medium (between 600 lbm and 2200 lbm)	This term represents the probability that the amount of hydrogen produced is between 600 lbm and 2200 lbm during accidents with 20% core melt, no early injection, and no late recirculation cooling. Phase II SAMA 011, to provide containment inerting capability to prevent combustion of hydrogen and carbon monoxide, was evaluated.
NO_QUENCH-3	1.0	1.047	No debris quench, given dry reactor pit and no late water supply after vessel breach	This term represents the probability that debris is not quenched immediately after vessel failure, with no water inside the reactor pit at vessel breach and no late water supply for debris cooling after vessel breach. Phase II SAMAs 008 and 009, to contain molten core debris in the reactor pit area and to create a reactor cavity flooding system, were evaluated.
BURN_VF1-E_DEF	0.5	1.042	Hydrogen burn occurs under medium hydrogen conditions	This term represents the probability of a hydrogen burn occurring at vessel failure, given a medium hydrogen concentration early, no prior early burns, and DCH. Phase II SAMA 011, to provide containment inerting capability to prevent combustion of hydrogen and carbon monoxide, was evaluated.

Table E.1-5
IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
CFE@VF_2	0.997	1.039	Containment failure given containment pressure > 23 psig, dry reactor pit, H2 burn and DCH	This term represents the probability that containment failure results from pressure rise at vessel failure given containment pressure greater than 23 psig, no water in the reactor pit, DCH, and hydrogen burn. Phase II SAMAs 009, 010, 011, 012, 013, 014, 015, and 016, for enhancing containment integrity, were evaluated. In addition, Phase II SAMAs 040, 045, 053, and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated.
CFE@VF_9	0.24	1.037	Containment failure given containment pressure > 23 psig, dry reactor pit, and DCH	This term represents the probability that containment failure results from pressure rise at vessel failure given containment pressure greater than 23 psig, no water in the reactor pit, and DCH. Phase II SAMAs 009, 010, 011, 012, 013, 014, 015, and 016 for enhancing containment integrity, were evaluated. In addition, Phase II SAMAs 040, 045, 053, and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated.

Table E.1-5
IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
NO_DISPERSAL	0.9	1.031	Core debris is not dispersed into containment atmosphere at vessel breach	This term represents the probability that debris is not dispersed and cooled following an HPME or an in-vessel or ex-vessel steam explosion event. Phase II SAMAs 040, 045, 053, and 057 to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated.
PDS_FRAC-45	3.13E-02	1.025	Long-term internal flood induced SBO sequence	This term is the plant damage state split fraction for a long-term internal flood event that entails failure of normal offsite supply buses, vital AC safeguard buses and loss of the AFW turbine-driven pump. With no secondary-side heat removal, core damage results at high RCS pressure. Phase II SAMAs 054, 060, 061, 062 and 065, to install a flood alarm in the 480VAC switchgear room, to provide added protection against flood propagation into the 480VAC switchgear room, to provide a hard-wired connection to a SI pump from the ASSS power supply, and to upgrade the ASSS to allow timely restoration of seal injection and cooling, were evaluated.
DP-40	0.975	1.024	RCS pressure is low at vessel breach given a long-term internal flood induced SBO sequence	This term represents the probability that RCS depressurization occurs during a long-term internal flood induced SBO sequence. Phase II SAMAs 040, 045, 053, and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs were evaluated.

Table E.1-5
IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
ELK4-P40	0950	1.024	Small containment failure during a long-term internal flood induced SBO sequence at high RCS pressure	This term represents the probability that a small containment failure occurs following a long-term internal flood induced SBO sequence at high RCS pressure. Phase II SAMAs 009, 010, 011, 012, 013, 014, 015, and 016, for enhancing containment integrity, were evaluated.
NO_QUENCH-2	0.5	1.023	No debris quench, given dry reactor pit and late water supply after vessel breach	This term represents the probability that debris is not quenched immediately after vessel failure, without water inside the reactor pit at vessel breach, but with a late water supply for debris cooling after vessel breach. Phase II SAMAs 008 and 009, to contain molten core debris in the reactor pit area and to create a reactor cavity flooding system, were evaluated.
PDS_FRAC-49	5.58E-04	1.016	Long-term small ISLOCA outside containment event	This term is the plant damage state split fraction for a long-term small break ISLOCA outside containment. Phase II SAMAs 021, 022, 023, and 024, to install additional pressure or leak monitoring instrumentation, increase leak testing of ISLOCA valves, add redundant and diverse limit switches to containment isolation valves, and ensure ISLOCA releases are scrubbed, were evaluated.
BURN_EARLY1_DEF	0.1	1.015	Hydrogen deflagration burn occurs	This term represents the probability that an early hydrogen burn occurs. Phase II SAMA 011, to provide containment inerting capability to prevent combustion of hydrogen and carbon monoxide, was evaluated. In addition, Phase II SAMAs 009, 010, 012, 013, 014, 015, and 016, for enhancing containment integrity, were evaluated.

Table E.1-5
IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
CFE_BURN2-H2_CFE	7.0E-02	1.015	Early hydrogen burn fails containment	This term represents the probability that an early hydrogen burn fails containment due to overpressure. Phase II SAMA 011, to provide containment inerting capability to prevent combustion of hydrogen and carbon monoxide, was evaluated. In addition, Phase II SAMAs 009, 010, 012, 013, 014, 015, and 016, for enhancing containment integrity, were evaluated.
PDS_FRAC-48	1.02E-02	1.008	Long-term internal flood induced SBO sequence at medium RCS pressure	This term is the plant damage state split fraction for a long-termed internal flood event that entails failure of normal offsite supply buses, vital AC safeguard buses and the occurrence of a RCP seal LOCA occurs with no AFW turbine-driven pump available. Phase II SAMAs 054, 060, 061, 062 and 065, to install a flood alarm in the 480VAC switchgear room, to provide added protection against flood propagation into the 480VAC switchgear room, to provide a hard-wired connection to a SI pump from the ASSS power supply, and to upgrade the ASSS to allow timely restoration of seal injection and cooling, were evaluated.
DP-43	0.975	1.008	RCS pressure is medium at vessel breach given a long-term internal flood induced SBO sequence at medium RCS pressure	This term represents the probability that RCS depressurization occurs during a long-term internal flood induced SBO sequence in which a RCP seal LOCA occurs with no AFW turbine-driven pump available. Phase II SAMAs 040, 045, 053, and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs, were evaluated.

Table E.1-5
IP2 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
ELK4-P43	0950	1.008	Small containment failure during a long-term internal flood induced SBO sequence at medium RCS pressure	This term represents the probability that a small containment failure occurs following a long-term internal flood induced SBO sequence in which a RCP seal LOCA occurs with no AFW turbine-driven pump available. Phase II SAMAs 009, 010, 011, 012, 013, 014, 015, and 016, for enhancing containment integrity, were evaluated.
ALPHA	0.1	1.006	Given in-vessel FCI, 'ALPHA' mode failure, fails reactor and containment	This term represents the probability of vessel and containment failure given an in-vessel fuel-coolant interaction (ALPHA mode failure). Phase II SAMAs 034, 035, 036, 037, 038, and 039, for enhancing reactor vessel injection and recirculation cooling, were evaluated.
FCI_IV_3	0.1	1.006	Low pressure fuel coolant interaction occurs	This term represents the probability that a fuel-coolant interaction occurs inside the reactor vessel at low RCS pressure. Phase II SAMAs 034, 035, 036, 037, 038, and 039, for enhancing reactor vessel injection and recirculation cooling, were evaluated.
HPME_2	0.9	1.004	HPME occurs at medium RCS pressure	This term represents the probability that HPME occurs at RCS pressure between 675 psig and 2235 psig. Phase II SAMAs 040, 045, 053, and 057, to enhance RCS depressurization systems, replace PORVs with larger ones, keep both pressurizer PORV block valves open, and provide DC power backup for the PORVs, were evaluated.

E.1.2.2 Radionuclide Analysis

This subsection provides the following information regarding characterization of the Level 2 CET end states.

- Overview of PDS
- Overview of radionuclide removal processes and the concept of binning
- Identification of radionuclide release categories
- Release category bin assignments
- Process used to group the numerous source terms
- MAAP deterministic calculations to support CET end states definition
- Consequence analysis source terms

E.1.2.2.1 Overview of PDS

The interface between the Level 1 Systems Analysis and the Level 2 Containment Performance Analysis consists of a set of PDS. The PDS are defined by a set of functional characteristics for system operation, which are important to accident progression, containment failure and source term definition. Each PDS contains Level 1 sequences with sufficient similarity in system functional characteristics that the containment accident progression for all sequences in the group can be considered to be essentially the same. Each PDS defines a unique set of conditions regarding the state of the plant and containment building systems and the physical state of the core, reactor coolant system and the containment boundary at (approximately) the time of core damage or vessel failure. The important functional characteristics for each PDS were determined by defining the critical parameters (system functions), which impact the key results. The sequence characteristics that are important were defined by the requirements of the containment accident progression analysis. They include the type of accident initiator, the operability or non-operability of important systems, the value of important plant variables (e.g., primary system pressure) which are defined by system operation, and timing of key events.

Based on the above criteria, the Level 1 results were binned into 57 PDS. These PDS define important combinations of system states that can result in distinctly different accident progression pathways and therefore, different containment failure and source term characteristics. Table E.1-6 provides a description of the IP2 PDS that are used to summarize the Level 1 results.

The PDS designators listed in Table E.1-6 represent the core damage end state categories from the Level 1 analyses that are grouped together as entry conditions for the Level 2 analysis. The Level 2 accident progression for each of the PDS is evaluated using a single CET to determine the appropriate release category for each Level 2 sequence. Each end state associated with a Level 2 sequence is assigned to a unique release category.

Table E.1-6
Summary of IP2 Internal Events PDS

Plant Damage State	Description	Frequency/ ry
PDS-1	Long-term small-break LOCA event with subsequent loss of secondary cooling. The containment is not bypassed and AC power is available. Core damage proceeds at high RCS pressure (>2350psia). Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	2.12E-09
PDS-2	Same as PDS-1, except random faults fail the containment fan coolers.	1.97E-10
PDS-3	Same as PDS-1, except random faults fail the containment fan coolers and containment injection spray systems.	0.00E+00
PDS-4	Long-term medium or small LOCA scenario with loss of recirculation cooling. Core damage results at medium RCS pressure (>675psia and <2350psia). Containment is not bypassed and AC power is available. Late vessel injection, secondary-side cooling, containment fan coolers and containment spray are available after the onset of core damage.	9.25E-07
PDS-5	Same as PDS-4, except random faults fail the containment fan coolers.	2.51E-08
PDS-6	Same as PDS-4, except random faults fail the containment fan coolers and containment injection spray system.	5.14E-08
PDS-7	Same as PDS-4, except random faults fail containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-8	Long-term medium LOCA. Although vessel injection is successful, random faults fail all modes of operation of the high-head recirculation core cooling systems. With no long-term core cooling, core damage proceeds at medium RCS pressure (> 675psia and < 2350psia). Containment is not bypassed and AC power is available. Late vessel injection, containment injection sprays and containment recirculation sprays are not available. However, secondary-side cooling and containment fan coolers are available after the onset of core damage.	1.75E-10
PDS-9	Same as PDS-8, except random faults fail containment fan coolers.	9.42E-09
PDS-10	Long-term medium LOCA with subsequent loss of secondary-side cooling and recirculation cooling. Core damage results at medium RCS pressure (> 675psia and < 2350psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	3.47E-11

Table E.1-6
Summary of IP2 Internal Events PDS
(Continued)

Plant Damage State	Description	Frequency/ ry
PDS-11	Same as PDS-10, except random faults fail the containment fan coolers and containment injection spray system.	0.00E+00
PDS-12	Same as PDS-10, except random faults fail containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-13	Long-term medium LOCA with subsequent random failure of secondary-side cooling and all modes of operation of the high-head recirculation core cooling systems. Core damage results at medium RCS pressure (> 675psia and < 2350psia). Containment is not bypassed and AC power is available. Late vessel injection is not available. Although containment fan coolers are available, both containment injection sprays and containment recirculation sprays are not available after the onset of core damage.	0.00E+00
PDS-14	Same as PDS-13, except random faults fail the containment fan coolers.	0.00E+00
PDS-15	Short-term large LOCA with either a loss of initial injection or loss of recirculation cooling. Core damage results at low RCS pressure (< 675 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment sprays are available after the onset of core damage.	1.90E-07
PDS-16	Same as PDS-15, except random faults fail the containment fan coolers.	2.07E-11
PDS-17	Same as PDS-15, except random faults fail the containment fan coolers and containment injection spray system.	0.00E+00
PDS-18	Same as PDS-15, except random faults fails containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-19	Short-term large LOCA. Although initial injection is successful, random faults fail both the recirculation pumps and RHR pumps for long-term recirculation cooling. Core damage results at low RCS pressure (< 675 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment injection spray and containment recirculation spray are not available. However, containment fan coolers are available after the onset of core damage.	0.00E+00
PDS-20	Same as PDS-19, except random faults fail the containment fan coolers.	0.00E+00

Table E.1-6
Summary of IP2 Internal Events PDS
(Continued)

Plant Damage State	Description	Frequency/ ry
PDS-21	Short-term ATWS event with AFW available and loss of long-term reactor subcriticality control. RCS pressure remains at the PORV setpoint, precluding high- and low-head safety injection. Therefore, core damage occurs in the short-term at high RCS pressure (> 2350 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	9.77E-07
PDS-22	Long-term transient involving loss of secondary cooling and subsequent loss of primary bleed-and-feed core cooling. Core damage results at high RCS pressure (> 2350 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment sprays are available after the onset of core damage.	3.38E-06
PDS-23	Same as PDS-22, except random faults fail the containment fan coolers.	3.88E-06
PDS-24	Same as PDS-22, except random faults fails the containment fan coolers and containment injection spray system.	2.19E-08
PDS-25	Long-term transient with a subsequent loss of secondary cooling. Following successful bleed-and-feed core cooling, failure to implement long-term recirculation cooling occurs. Core damage results at medium RCS pressure (> 675 psia and < 2350 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	2.47E-08
PDS-26	Same as PDS-25, except random faults fail the containment fan coolers.	1.02E-10
PDS-27	Same as PDS-25, except random faults fail the containment fan coolers and containment injection spray system.	0.00E+00
PDS-28	Same as PDS-25, except random faults fail containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-29	Long-term transient with subsequent loss of secondary cooling. Following successful bleed-and-feed core cooling, random faults fail long-term recirculation cooling. Core damage results at medium RCS pressure. Containment is not bypassed and AC power is available. Late vessel injection, containment injection spray and containment recirculation spray are unavailable after the onset of core damage. However, the containment fan coolers are available.	3.85E-11

Table E.1-6
Summary of IP2 Internal Events PDS
(Continued)

Plant Damage State	Description	Frequency/ ry
PDS-30	Same as PDS-29, except random faults fail the containment fan coolers.	2.47E-07
PDS-31	Long-term RCP seal LOCA caused by loss of CCW to the RCP seals. Core damage results at medium RCS pressure. Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	1.81E-06
PDS-32	Same as PDS-31, except random faults fail the containment fan coolers.	4.44E-07
PDS-33	Same as PDS-31, except random faults fails containment fan coolers and containment injection spray system.	3.08E-07
PDS-34	Same as PDS-31, except random faults fails containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-35	Stuck open PORV with loss of long-term recirculation cooling. Core damage results at medium RCS pressure. Containment is not bypassed and AC power is available. Late vessel injection, containment injection spray and containment recirculation spray are unavailable after the onset of core damage. However, the containment fan coolers are available.	6.42E-09
PDS-36	Same as PDS-35, except random faults fail the containment fan coolers.	4.21E-07
PDS-37	SBO sequence in which a loss of all DC power occurs in the long term. No PORVs stick open. Secondary cooling by the AFW system is unavailable because the SBO renders both motor-driven AFW pumps inoperable, and the steam-turbine-driven AFW pump fails because of battery depletion or random faults. Without primary and secondary cooling, core damage occurs at high RCS pressure. Containment is not bypassed. All accident-mitigating functions are recoverable when offsite power is restored.	7.41E-09
PDS-38	Short-term SBO sequence with immediate loss of secondary cooling. Core damage results at high RCS pressure. Containment is not bypassed. All accident-mitigating functions are recoverable when offsite power is restored.	1.06E-07
PDS-39	Same as PDS-37, except RCS depressurization results from either operator action or a single PORV sticking open. Core damage results at medium RCS pressure. Containment is not bypassed. All accident-mitigating functions are recoverable when offsite power is restored.	3.95E-07

Table E.1-6
Summary of IP2 Internal Events PDS
(Continued)

Plant Damage State	Description	Frequency/ry
PDS-40	Short-term SBO sequence with immediate loss of secondary cooling and subsequent RCP seal LOCA or stuck-open PORV. Core damage results at medium RCS pressure. Containment is not bypassed. All accident-mitigating functions are recoverable when offsite power is restored.	0.00E+00
PDS-41	Short-term large LOCA induced by vessel rupture. The LOCA is beyond the capability of the ECCS. Core damage occurs in the short term with the RCS at low pressure. Vessel injection and all forms of containment heat removal (containment fan coolers, RHR heat exchangers, and containment sprays) are available. Containment is not bypassed and AC power is available.	1.28E-07
PDS-42	Same as PDS-41, except random faults fail the containment fan coolers.	0.00E+00
PDS-43	Same as PDS-41, except random faults fail the containment fan coolers and containment injection spray system.	0.00E+00
PDS-44	Same as PDS-41, except random faults fail the containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-45	Long-term internal flood induced SBO sequence in which loss of AFW steam-turbine-driven pump occurs. With no secondary-side heat removal, core damage results at high RCS pressure. Because of the flood, core cooling and containment heat removal systems are unavailable after the onset of core damage. Containment is not bypassed.	9.36E-07
PDS-46	Short-term internal flood induced SBO sequence in which loss of secondary heat removal occurs. Core damage results at high RCS pressure. Because of the flood, core cooling and containment heat removal systems are not available after the onset of core damage.	1.02E-07
PDS-47	Long-term internal flood induced SBO with a subsequent stuck-open PORV or RCP seal LOCA. Core damage ensues at medium RCS pressure. The steam-turbine-driven AFW pump is available after core damage. However, core cooling and containment heat removal systems are unavailable because of the internal flooding event. The containment is not bypassed.	2.31E-06
PDS-48	Short-term internal flood induced SBO sequence in which loss of secondary heat removal occurs and a subsequent breach of RCS integrity occurs because of a stuck-open PORV or RCP seal LOCA. Core damage results at medium RCS pressure. Because of the flood, core cooling and containment heat removal systems are not available after the onset of core damage.	3.06E-07

Table E.1-6
Summary of IP2 Internal Events PDS
(Continued)

Plant Damage State	Description	Frequency/ ry
PDS-49	Long-term small break ISLOCA occurs outside containment. Core damage results at medium RCS pressure with a bypassed containment. While vessel injection and all modes of containment spray are unavailable, containment fan coolers are available after core damage.	9.97E-09
PDS-50	Short-term large break ISLOCA occurs outside containment. Core damage results at low RCS pressure with a bypassed containment. While vessel injection and all modes of containment spray are unavailable, containment fan coolers are available after core damage.	1.42E-07
PDS-51	SGTR and a failure to isolate the ruptured steam generator. Because RCS pressure remains above the ruptured steam generator pressure, water lost from the RCS does not return to the containment sump and recirculation core cooling is unavailable. Core damage results at medium RCS pressure with a bypassed containment. While vessel injection and all modes of containment sprays are unavailable, containment fan coolers are available after core damage.	4.30E-07
PDS-52	Same as PDS-51, except random faults fail containment fan coolers.	2.76E-09
PDS-53	Same as PDS-51, except random faults fail AFW to the steam generators and the containment fan coolers.	2.33E-09
PDS-54	Same as PDS-51, except the ruptured steam generator is isolated.	2.60E-07
PDS-55	Same as PDS-51 except the ruptured steam generator is isolated and random faults fail the containment fan coolers.	6.55E-09
PDS-56	Same as PDS-51, except the ruptured steam generator is isolated and random faults fail AFW to the steam generators.	8.88E-09
PDS-57	Same as PDS-51, except the ruptured steam generator is isolated, random faults fail AFW to the steam generators and the containment fan coolers.	1.49E-09
	Total	1.79E-05

E.1.2.2.2 Overview of Radionuclide Removal Processes and Concept of Binning

A major feature of a Level 2 analysis is the estimation of the source term for every possible outcome of the CET. The CET end points represent the outcomes of possible in-containment accident progression sequences. These end points represent complete severe accident sequences from initiating event to release of radionuclides to the environment. The Level 1 and plant system information is passed through to the CET evaluation in discrete PDS. An atmospheric source term may be associated with each of these CET sequences. Because of the large number of postulated accident scenarios considered, mechanistic calculations (i.e., MAAP calculations) are not performed for every end-state in the CET. Rather, accident sequences produced by the CET are grouped or "binned" into a limited number of release categories, each of which represents all postulated accident scenarios that would produce a similar fission product source term.

The criteria used to characterize the release are the estimated magnitude of total release and the timing of the first significant release of radionuclides. The predicted source term associated with each release category, including both the timing and magnitude of the release, is determined using the results of MAAP calculations.

E.1.2.2.3 Identification of Radionuclide Release Categories

E.1.2.2.3.1 Timing of Release

Timing completely governs the extent of radioactive decay of short-lived radioisotopes prior to an offsite release and, therefore, has a first-order influence on immediate health effects. IP2 characterizes the release timing relative to the time at which the release begins, measured from the time of accident initiation. Two timing categories are used, as follows.

(1) Early: rapid, unmitigated release of airborne fission products from the containment to the environment occurring before the effective implementation of offsite emergency response and protective actions. This involves CET endstates in which containment failure occurs within 0 to 12 hours from the initiating event.

(2) Late: mitigated release of airborne fission products from the containment to the environment occurring after effective implementation of offsite emergency response and protective actions. This involves CET endstates in which containment failure occurs after 12 hours from the initiating event.

The definition of the release category timing takes into consideration the compensatory measures available to reduce or prevent dose to the public and the characteristics of the radionuclide release. Compensatory measures are prescribed in the emergency response plan. These actions, which are routinely practiced, are geared to mobilizing utility resources to implement emergency procedures, assess the potential offsite consequence of an accident, and recommend to government officials appropriate action for protecting the public (evacuate or shelter).

An evacuation time estimates study performed for the Indian Point Energy Center (IPEC) site [Reference E.1-7], examined fourteen evacuation scenarios under which evacuation times are calculated to successfully evacuate 100 percent of the general public. The ranges of times for those 14 scenarios for the following emergency planning zone rings (shortest to longest in hours: minutes) are as follows:

2 miles:	4:30 to 6:50;
5 miles:	5:25 to 8:00;
10 miles:	7:10 to 12:00.

Since the 10-mile emergency planning zone may not be evacuated for 12 hours from the initiating event, 12 hours is the upper bound time in which an early release can occur.

E.1.2.2.3.2 Magnitude of Release

Source term results from previous risk studies suggest that categorization of release magnitude based on cesium iodide (CsI) release fractions alone are appropriate [Reference E.1-5]. The CsI release fraction indicates the fraction of in-vessel radionuclides escaping to the environment. (Noble gas release levels are non-informative since release of the total core inventory of noble gases is essentially complete given containment failure).

The source terms were grouped into five distinct radionuclide release categories or bins according to release magnitude as follows.

(1) High: A radionuclide release of sufficient magnitude to have the potential to cause early fatalities. This implies a total integrated release of >10% of the initial core inventory of CsI [Reference E.1-5].[1]

(2) Medium: A radionuclide release of sufficient magnitude to cause near-term health effects. This implies a total integrated release of between 1% and 10% of the initial core inventory of CsI [Reference E.1-5].[2]

(3) Low: A radionuclide release with the potential for latent health effects. This implies a total integrated release of between 0.1% and 1% of the initial core inventory of CsI.

(4) Low-Low: A radionuclide release with undetectable or minor health effects over most of the population. This implies a total integrated release of between 0.01% and 0.1% of the initial core inventory of CsI.

1. Once the CsI source term exceeds 0.1, the source term is large enough that doses above the early fatality threshold can sometimes occur within a population center a few miles from the site.
2. The reference document indicates that for CsI release fractions of 1 to 10 percent, the number of latent fatalities is found to be at least 10% of the latent fatalities for the highest release.

(5) Negligible or no containment failure (NCF): A radionuclide release that is less than or equal to the containment design base leakage. This implies total integrated release of < 0.01% of the initial core inventory of CsI.

E.1.2.2.4 Release Category Bin Assignments

The combination of release magnitude and timing produce nine distinct release categories. Table E.1-7 summarizes the scheme used to bin CET sequences with respect to magnitude of release, based on the predicted CsI release fraction and release timing.

Table E.1-7
IP2 Release Severity and Timing Classification Scheme Summary

Release Severity		Release Timing	
Classification Category	**Percent CsI Release**	**Classification Category**	**Time of Initial Release From Accident Initiation**
High	Greater than 10	Early (E)	Less than 12 hours
Medium	1 to 10		
Low	0.1 to 1	Late (L)	Greater than 12 hours
Low-Low	0.01 to 0.1		
NCF	Less than < 0.01		

E.1.2.2.5 Process Used to Group the Source Terms

The approach used to evaluate radionuclide releases and develop release categories is similar to that applied in the NUREG-1150 analysis; i.e., a source term was associated with each CET end-state that was found to have a significant frequency. The objectives were to establish the timing of the first significant release of radionuclides and estimate the magnitude of the total release.

The first step in the source term assessment effort was to identify the sequence characteristics that are most important for defining the source term. These characteristics were identifiable from the PDS characteristics and from the CET sequence characteristics since one of the primary objectives in the PDS grouping and CET evaluation was to define those events and conditions most important for source term assessment. The set of sequence characteristics important to source term assessment was used as grouping criteria to define the release categories and the associated source term magnitude, composition and timing.

The containment sequence characteristics selected for use in definition of the IP2 source term release categories are

- vessel breach,
- containment failure,
- core-concrete interactions (CCI),
- fission product removal,
- PAB retention.

The goal of the grouping process was to develop the minimum number of release categories necessary to distinguish the important combinations of sequence characteristics that can result in distinctly different atmospheric source terms.

The second step was to classify the various progressions paths in the IP2 CET as unique release end states based on the sequence characteristics. The release modes were categorized into the following general classifications:

- end states recovered in-vessel (no vessel breach);
- end states recovered ex-vessel (vessel breach, but no CCI);
- end states that are late containment failures;
- end states that are early containment failures.

Each CET end state represents a particular release event or a recovered, degraded core state that may be characterized according to its potential for fission product release to the atmosphere, its timing of release initiation relative to time of incipient core damage, and its release duration.

Table E.1-8 summarizes the possible CET release categories for the spectrum of core melt accident sequences. This table defines the various CET release modes as early or late release events and containment damage states (i.e., failure modes), including recovered states and release mechanisms (i.e., no CCI). Each release mode represents a release path from the fuel through the primary coolant system and the containment atmosphere to the environment, should the containment ultimately fail or be bypassed. The release path (including the associated removal mechanism) is related to a particular environmental source term.

The consolidation of source term results for the CET release categories presented in Table E.1-8 was accomplished by "binning" or grouping releases into release categories that represent all postulated accident scenarios that produce a similar fission product source term. The criteria used to characterize the release are the estimated magnitude of total release and the timing of the first significant release of radionuclides.

Based on the above binning methodology, the salient Level 2 results are summarized in Table E.1-9. This table identifies the total annual release frequency for each Level 2 release category.

Table E.1-8
Description of IP2 CET Release Modes

Accident Progression Bin	CET Sequence Description	Release Timing (based on MAAP)	Release Magnitude (based on MAAP)	CET Release Category
APB-1	Recovered in-vessel, no vessel breach, no containment failure	NA	Negligible	NCF
APB-2	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early Low
APB-3	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release not mitigated	Early	Medium	Early Medium
APB-4	Vessel breach at low pressure, recovered ex-vessel, no containment failure	NA	Negligible	NCF
APB-5	Vessel breach at low pressure, recovered ex-vessel, late containment leak failure, in-vessel fission product release mitigated	Late	Low-Low	Late Low-Low
APB-6	Vessel breach at low pressure, recovered ex-vessel, late containment leak failure, in-vessel fission product release not mitigated	Late	Medium	Late Medium
APB-7	Vessel breach at low pressure, recovered ex-vessel, late containment rupture failure, in-vessel fission product release not mitigated	Late	High	Late High
APB-8	Vessel breach at low pressure, CCI occurs, no containment failure	NA	Negligible	NCF
APB-9	Vessel breach at low pressure, CCI occurs, late containment leak failure, ex-vessel fission product release mitigated by overlying pool, in-vessel release mitigated by sprays	Late	Low-Low	Late Low-Low

Table E.1-8
Description of IP2 CET Release Modes

Accident Progression Bin	CET Sequence Description	Release Timing (based on MAAP)	Release Magnitude (based on MAAP)	CET Release Category
APB-10	Vessel breach at low pressure, CCI occurs, late containment rupture failure, ex-vessel fission product release mitigated by overlying pool, in-vessel release mitigated by sprays	Late	Low	Late Low
APB-11	Vessel breach at low pressure, CCI occurs, late containment leak failure, ex-vessel fission product release mitigated by overlying pool, in-vessel release not mitigated	Late	Medium	Late Medium
APB-12	Vessel breach at low pressure, CCI occurs, late containment rupture failure, ex-vessel fission product release mitigated by overlying pool, in-vessel release not mitigated	Late	High	Late High
APB-13	Vessel breach at low pressure, no CCI, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early Low
APB-14	Vessel breach at low pressure, no CCI, early containment rupture failure, in-vessel fission product release mitigated	Early	Medium	Early Medium
APB-15	Vessel breach at low pressure, no CCI, early containment leak failure, in-vessel fission product release not mitigated	Early	High	Early High
APB-16	Vessel breach at low pressure, no CCI, early containment rupture failure, in-vessel fission product release not mitigated	Early	High	Early High
APB-17	Vessel breach at low pressure, significant CCI occurs, early containment leak failure, in- and ex-vessel fission product release mitigated	Early	Low	Early Low

Table E.1-8
Description of IP2 CET Release Modes

Accident Progression Bin	CET Sequence Description	Release Timing (based on MAAP)	Release Magnitude (based on MAAP)	CET Release Category
APB-18	Vessel breach at low pressure, significant CCI occurs, early containment rupture failure, in- and ex-vessel fission product release mitigated	Early	Medium	Early Medium
APB-19	Vessel breach at low pressure, significant CCI occurs, early containment leak failure, ex-vessel fission product release mitigated by overlying pool, in-vessel fission product release not mitigated	Early	High	Early High
APB-20	Vessel breach at low pressure, significant CCI occurs, early containment rupture failure, ex-vessel fission product release mitigated by overlying pool, in-vessel fission product release not mitigated	Early	High	Early High
APB-21	Recovered in-vessel, no vessel breach, no containment failure	NA	Negligible	NCF
APB-22	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early-Low
APB-23	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release not mitigated	Early	Medium	Early-Medium
APB-24	Vessel breach at low pressure, recovered ex-vessel, no containment failure	NA	Negligible	NCF
APB-25	Vessel breach at low pressure, no CCI, late containment leak failure, in-vessel fission product release mitigated by sprays	Late	Low-Low	Late Low-Low
APB-26	Vessel breach at low pressure, no CCI, late containment rupture failure, in-vessel fission product release mitigated by sprays	Late	Low	Late Low

Table E.1-8
Description of IP2 CET Release Modes

Accident Progression Bin	CET Sequence Description	Release Timing (based on MAAP)	Release Magnitude (based on MAAP)	CET Release Category
APB-27	Vessel breach at low pressure, no CCI, late containment leak failure, in-vessel fission product release not mitigated	Late	Medium	Late Medium
APB-28	Vessel breach at low pressure, no CCI, late containment rupture failure, in-vessel fission product release not mitigated	Late	High	Late High
APB-29	Vessel breach at low pressure, CCI occurs, no containment failure	NA	Negligible	NCF
APB-30	Vessel breach at low pressure, significant CCI occurs, late containment leak failure, in- and ex-vessel fission product release mitigated by sprays	Late	Low-Low	Late Low-Low
APB-31	Vessel breach at low pressure, significant CCI occurs, late containment rupture failure, in- and ex-vessel fission product release mitigated by sprays	Late	Low	Late Low
APB-32	Vessel breach at low pressure, significant CCI occurs, late containment leak failure, in- and ex-vessel fission product release not mitigated	Late	Medium	Late Medium
APB-33	Vessel breach at low pressure, significant CCI occurs, late containment rupture failure, in- and ex-vessel fission product release not mitigated	Late	High	Late High
APB-34	Vessel breach at low pressure, no CCI, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early Low
APB-35	Vessel breach at low pressure, no CCI, early containment rupture failure, in-vessel fission product release mitigated	Early	Medium	Early Medium
APB-36	Vessel breach at low pressure, no CCI, early containment leak failure, in-vessel fission product release not mitigated	Early	High	Early High

Table E.1-8
Description of IP2 CET Release Modes

Accident Progression Bin	CET Sequence Description	Release Timing (based on MAAP)	Release Magnitude (based on MAAP)	CET Release Category
APB-37	Vessel breach at low pressure, no CCI, early containment rupture failure, in-vessel fission product release not mitigated	Early	High	Early High
APB-38	Vessel breach at low pressure, significant CCI occurs, early containment leak failure, in- and ex-vessel fission product release mitigated by sprays	Early	Low	Early Low
APB-39	Vessel breach at low pressure, significant CCI occurs, early containment rupture failure, in- and ex-vessel fission product release mitigated by sprays	Early	Medium	Early Medium
APB-40	Vessel breach at low pressure, significant CCI occurs, early containment leak failure, fission product not mitigated	Early	High	Early High
APB-41	Vessel breach at low pressure, significant CCI occurs, early containment rupture failure, fission product not mitigated	Early	High	Early High
APB-42	Recovered in-vessel, no vessel breach, no containment failure	NA	Negligible	NCF
APB-43	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early Low
APB-44	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release not mitigated	Early	Medium	Early Medium
APB-45	Vessel breach at high pressure, CCI occurs, no containment failure	NA	Negligible	NCF
APB-46	Vessel breach at high pressure, no CCI, late containment leak failure, in-vessel and late fission product release mitigated by sprays	Late	Low	Late Low

Table E.1-8
Description of IP2 CET Release Modes

Accident Progression Bin	CET Sequence Description	Release Timing (based on MAAP)	Release Magnitude (based on MAAP)	CET Release Category
APB-47	Vessel breach at high pressure, no CCI, late containment rupture failure, in-vessel and late fission product release mitigated by sprays	Late	Low	Late Low
APB-48	Vessel breach at high pressure, no CCI, late containment leak failure, in-vessel and late fission product release not mitigated	Late	Medium	Late Medium
APB-49	Vessel breach at high pressure, no CCI, late containment rupture failure, in-vessel and late fission product release not mitigated	Late	High	Late High
APB-50	Vessel breach at high pressure, CCI occurs, no containment failure	NA	Negligible	NCF
APB-51	Vessel breach at high pressure, moderate CCI occurs, late containment leak failure, in- and ex-vessel fission product release mitigated by Sprays	Late	Low	Late Low
APB-52	Vessel breach at high pressure, moderate CCI occurs, late containment rupture failure, in- and ex-vessel fission product release mitigated by Sprays	Late	Low	Late Low
APB-53	Vessel breach at high pressure, moderate CCI occurs, late containment leak failure, in- and ex-vessel, fission product release not mitigated	Late	Medium	Late Medium
APB-54	Vessel breach at high pressure, moderate CCI occurs, late containment rupture failure, in- and ex-vessel, fission product release not mitigated	Late	High	Late High
APB-55	Vessel breach at high pressure, no CCI, early containment leak failure, in-vessel and late fission product release mitigated	Early	Medium	Early Medium
APB-56	Vessel breach at high pressure, no CCI, early containment rupture failure, in-vessel and late fission product release mitigated	Early	Medium	Early Medium

Table E.1-8
Description of IP2 CET Release Modes

Accident Progression Bin	CET Sequence Description	Release Timing (based on MAAP)	Release Magnitude (based on MAAP)	CET Release Category
APB-57	Vessel breach at high pressure, no CCI, early containment leak failure, in-vessel and late fission product release not mitigated	Early	Medium	Early Medium
APB-58	Vessel breach at high pressure, no CCI, early containment rupture failure, in-vessel and late fission product release not mitigated	Early	High	Early High
APB-59	Vessel breach at high pressure, moderate CCI occurs, early containment leak failure, in- and ex-vessel fission product release mitigated by sprays	Early	Medium	Early Medium
APB-60	Vessel breach at high pressure, moderate CCI occurs, early containment rupture failure, in- and ex-vessel fission product release mitigated by sprays	Early	Medium	Early Medium
APB-61	Vessel breach at high pressure, moderate CCI occurs, early containment leak failure, ex-vessel and late fission product release not mitigated	Early	Medium	Early Medium
APB-62	Vessel breach at high pressure, moderate CCI occurs, early containment rupture failure, ex-vessel and late fission product release not mitigated	Early	High	Early High

Table E.1-9
Summary of CET Quantification
IP2 PSA Model Revision 1

Release Category (Timing/Magnitude)	Release Frequency (Per year)
Late Low-Low	5.82E-08
Late Low	6.43E-07
Late Medium	3.43E-06
Late High	6.88E-07
Early Low-Low	0.00E+00
Early Low	1.11E-07
Early Medium	4.23E-07
Early High	6.50E-07
No Containment Failure (NCF)	1.19E-05
Total	**1.79E-05**

Nomenclature

Timing:

Late - Greater than 12 hours
Early - Less than 12 hours

Magnitude

NCF (Little to no release) - Less than 0.01% CsI
Low-Low - 0.01% to 0.1% CsI
Low - 0.1% to 1% CsI
Medium - 1% to 10% CsI
High - Greater than 10% CsI

E.1.2.2.6 MAAP Deterministic Calculations to Support CET End States Definition

The MAAP computer code is used to assign both the radionuclide release magnitude and timing based on the accident progression characterization. Specifically, MAAP provides the following information:

- containment pressure and temperature (time of containment failure is determined by comparing these values with the nominal containment capability);
- radionuclide release timing and magnitude for a large number of radioisotopes; and
- release fractions for twelve radionuclide species.

E.1.2.2.7 Consequence Analysis Source Terms

Input to the Level 3 IP2 model from the Level 2 model is a combination of radionuclide release fractions, timing of radionuclide releases, and frequencies at which the releases occur. This combination of information is used in conjunction with IP2 site characteristics in the Level 3 model to evaluate the offsite consequences of a core damage event.

Source terms were developed for the nine release categories identified in Table E.1-9. The MAAP computer code was used to generate the radionuclide release magnitude for the MACCS2 consequence analysis [Reference E.1-6]. The MAAP calculations are representative deterministic thermal hydraulic calculations that portray dominant CET scenarios.

Table E.1-10 provides a summary of the Level 2 results that were used as Level 3 input for the IP2 SAMA analysis.

The source terms presented in Table E.1-10 and used in the consequence analysis were determined as follows.

1. The appropriate MAAP case source terms were selected and assigned to a particular CET accident progression endstate.
2. Based on the source terms from Step 1, the source terms for each plant damage state CET accident progression endstate were determined.
3. The frequency of each release category was determined by summing the individual plant damage state CET accident progression endstates contained in the particular release category (i.e., no containment failure, early high release, etc.).
4. The release category individual fractional contributions for each CET accident progression were determined by dividing the result from Step 3 by the individual PDS frequencies.

5. Each PDS accident progression CET endpoint source terms, release timing, release energy and release elevation was multiplied by the value determine in Step 4.

6. The individual results of Step 5 were summed to arrive at the total final values contained in Table E.1-10.

Table E.1-10
IP2 Release Category Source Terms

	Release Characterization	Frequency (/ry)	Warning Time (sec)	Elevation (m)	Release Start (Hours)	Release Duration (Hours)	Release Energy (W)
1	NCF	1.19E-05	1.66E+04	3.00E+01	0.00E+00	3.55E+01	9.20E+05
2	Early High	6.50E-07	1.36E+04	3.00E+01	3.66E+00	2.29E+01	1.08E+06
3	Early Medium	4.23E-07	1.00E+04	3.00E+01	3.46E+00	2.70E+01	1.33E+06
4	Early Low	1.11E-07	1.09E+04	3.00E+01	4.81E+00	3.22E+01	1.60E+06
5	Early Low-Low	0.0	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
6	Late High	6.88E-07	5.58E+03	3.00E+01	2.05E+01	3.60E+01	9.20E+05
7	Late Medium	3.43E-06	8.94E+03	3.00E+01	2.23E+01	3.60E+01	9.20E+05
8	Late Low	6.43E-07	2.19E+04	3.00E+01	2.75E+01	3.60E+01	9.20E+05
9	Late Low-Low	5.82E-08	2.56E+04	3.00E+01	3.14E+01	3.60E+01	9.20E+05

Table E.1-10
IP2 Release Category Source Terms (continued)

	Release Fractions								
	NG	I	Cs	Te	Sr	Ru	La	Ce	Ba
1	9.27E-05	3.94E-06	1.61E-06	1.21E-06	3.74E-08	2.37E-07	2.11E-09	1.77E-08	1.05E-07
2	7.01E-01	2.43E-01	2.29E-01	2.26E-01	2.47E-02	9.13E-02	7.95E-04	4.84E-03	4.56E-02
3	9.87E-01	2.02E-02	1.75E-02	2.66E-02	8.33E-04	2.03E-02	4.92E-05	3.28E-04	1.33E-02
4	7.55E-01	5.93E-03	4.06E-03	3.89E-03	1.04E-04	1.97E-03	4.58E-06	3.31E-05	7.75E-04
5	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Table E.1-10
IP2 Release Category Source Terms (continued)

	Release Fractions								
	NG	**I**	**Cs**	**Te**	**Sr**	**Ru**	**La**	**Ce**	**Ba**
6	9.89E-01	1.17E-01	2.26E-02	4.81E-03	2.08E-04	3.74E-03	1.32E-05	1.22E-04	9.06E-04
7	8.23E-01	1.53E-02	4.30E-03	1.49E-03	8.01E-05	1.44E-03	5.11E-06	4.72E-05	3.50E-04
8	6.98E-01	1.06E-03	7.91E-04	1.23E-03	8.69E-05	3.47E-06	2.59E-06	2.38E-05	7.42E-05
9	9.09E-01	8.14E-04	6.96E-04	7.55E-04	3.63E-05	2.08E-06	1.14E-06	1.20E-05	3.33E-05

E.1.3 IPEEE Analysis

E.1.3.1 Seismic Analysis

The seismic portion of the IPEEE was completed in conjunction with the SQUG program [References E.1-8 and E.1-9]. IP2 performed a seismic probabilistic risk assessment (PRA) following the guidance of NUREG-1407 [Reference E.1-10] and NUREG/CR-2300 [Reference E.1-11]. The seismic PRA logic model was developed using a support state modeling approach similar to the IPE internal events model. The primary model difference is that a seismic event tree was developed to delineate the potential combinations of seismic-induced failures, and resulting seismic scenarios, which were termed "seismic damage states." Traditional event tree techniques were used to identify each of the top seismic-induced events and to formulate the nodal branching logic. The frequencies of these seismic damage states were quantified by convolving the site-specific mean earthquake hazard curve with the structure and equipment seismic fragility curves. This quantification included dependent and correlated failures, as well as random failures of equipment and operator actions. The seismic IPEEE containment performance analysis followed the guidance provided in NUREG-1407 to identify vulnerabilities that involve early failure of containment functions, including containment integrity, containment isolation and prevention of bypass functions. Although some seismic scenarios result in initial loss of containment pressure suppression and heat removal functions, no vulnerabilities which could cause early failures of containment, or containment bypass were identified.

The seismic PRA provides quantitative, but conservative, results. Therefore, its results should not be compared directly with the best-estimate internal events results.

Conservative assumptions in the seismic PRA include the following.

- Sequences in the seismic PSA involving loss of offsite power were assumed to be unrecoverable. If offsite power was recovered following a seismic event, there would be many more systems available to maintain core cooling and containment integrity than were credited for those sequences.

- A single, conservative, surrogate element whose failure leads directly to core damage was used in the seismic risk quantification to model the most seismically rugged components.

- Seismic-induced ATWS was considered in the analysis, but no credit was included for manual scram or mitigation of ATWS using the boration system. This conservatively resulted in most seismic-induced ATWS events leading to consequential core damage.

- Redundant components were conservatively assumed to be completely correlated by treating them as if they were one component for the purpose of determining the probability of seismic induced failures.

- Several systems were assumed to be unavailable during a seismic event, including

    a. the city water system, which can be used to supply backup cooling to the charging pumps if CCW is lost, as an alternate source of suction to the AFW pumps and to provide alternate cooling to the RHR and SI pumps;

    b. the primary water system, which can also be used as a backup to CCW to supply cooling to the RHR and SI pumps; and

    c. the onsite and offsite gas turbine generators, which can provide alternate station power.

- No credit was taken for recovery of power through the ASSS.

- Lawrence Livermore National Laboratory seismic hazard data was used. Use of EPRI seismic hazard data would result in a 10% reduction in overall seismic CDF.

The seismic CDF in the IPEEE was originally estimated to be 1.46 x 10^{-5} per year. As a result of an IPEEE recommendation, the CCW surge tank hold-down bolts were upgraded, reducing the seismic CDF to 1.06 x 10^{-5} per year. No other seismic improvements were recommended.

The conclusions of the IP2 seismic PRA are as follows.

- The total seismic CDF for IP2 is 1.06 x 10^{-5} per year.

- No unique decay heat removal vulnerabilities to seismic events were found because the safety-related systems provide effective and reliable means for reactor reactivity control, electrical power, RCS pressure control, decay heat removal, and containment pressure control.

- Seismic-induced flooding and fires do not pose major risks.

- No unique seismic-induced containment failure mechanisms were identified.

With the upgrade of the surge tank hold down bolts, the major contributors to seismic risk at IP2 are major structural failures rather than component failures. As a result, no further cost-effective changes to reduce seismic risk were identified in this effort.

Although the CDF due to seismic induced scenarios is a conservative value and the performance of mitigating systems and components has improved since the IPEEE was performed, the seismic risk contribution of 1.06 x 10^{-5} per year was used to determine the external event multiplier described in Section 4.21.5.4.

E.1.3.2 Fire Analysis

The IP2 internal fire risk model was performed in 1995 as part of the IPEEE submittal report [Reference E.1-8]. The IP2 fire analysis was performed using EPRI's Fire PRA Implementation Guide [Reference E.1-13]. The EPRI Fire Induced Vulnerability Evaluation method was used for the initial screening, and along with the EPRI Fire Events Database as the source of fire frequency data [References E.1-14 and E.1-23]. Unscreened fire zones were then analyzed in more detail using a fire PRA approach.

Table E.1-11 presents the results of the IP2 IPEEE fire analysis and the updated values used in this SAMA evaluation. The IPEEE values presented in Table E.1-11 are the same as those listed in NUREG-1742, [Reference E.1-12].

Conservative assumptions in the IP2 IPEEE fire analysis include the following.

- The frequency and severity of fires were generally conservatively overestimated in the generic IPEEE fire analysis methods. A revised Nuclear Regulatory Commission (NRC) fire events database indicates a trend toward lower frequency and less severe fires. This trend reflects improved housekeeping, reduction in transient fire hazards, and other improved fire protection steps at utilities.

- Cable failure due to fire damage was assumed to arise from open circuits, hot short circuits, and short circuits to ground. In damaging a cable, the analysis addressed the ability of the fire to induce the conductor failure mode of concern. Hot shorts were conservatively assigned a probability of 0.1, which was applied to all single phase, AC control circuit or DC power and control circuit cases regardless of whether the wires were in the same multi-conductor.

- A plant trip was assumed for all fires, including those for which immediate operator actions are not specified in emergency response procedures.

- The main feedwater and condensate systems were assumed to be unavailable in all scenarios, even when their power source was not impacted by the fire scenario. Use of these systems for recovery, following a failure of AFW, is addressed in current plant procedures.

- PORV block valves were assumed to be in the more limiting position (open or closed) to maximize the impact of the fire. As a result, risk important scenarios that included the potential for spurious LOCAs through the PORVs were also assumed to preclude the ability to close the PORV block valve, which was assumed, for those scenarios, to be in the open position (the PORV block valves at IP2 are currently maintained normally closed).

- All sequences involving induced RCP seal LOCAs were assumed to lead to complete seal failure. Although casualty cables exist for powering ECCS pumps from the ASSS power source, the ASSS was assumed to be ineffective in mitigating induced LOCAs. The currently accepted RCP seal LOCA methodology is more detailed and provides sequences with varying leakage rates. Under that current methodology, a majority of seal LOCAs remain within the capability of a charging pump (which has hardwired ASSS transfer capability) to provide makeup.

The dominant IPEEE fire sequences (sequences with CDF contributions > 1×10^{-7}) were re-evaluated to reduce the conservatisms associated with main feedwater and condensate unavailability, PORV block valves, and RCP seal LOCAs. Sequences with contributions of less than 1×10^{-7} were conservatively left as is. Also, the fire ignition frequency for the central control room main control board cabinets was reduced in accordance with current guidance provided in NUREG/CR-6850 [Reference E.1-24]. This re-evaluation resulted in a revised fire CDF of 9.11×10^{-6} per reactor-year, which represents a reduction of 2.02. Therefore, a reduction factor of two was applied in determining the external event multiplier described in Section 4.21.5.4.

Table E.1-11 lists the fire zones with the largest contribution to fire induced CDF at IP2. Although no specific hardware changes were recommended as a result of the IPEEE, a number of procedural and administrative improvements have been made, including:

- enhancing the controls for use, staging and storage of transient combustible materials;
- upgrading the fire protection training requirements for fire brigade members, personnel performing welding and hot work activities, and other plant personnel; and
- improving pre-fire plans and procedures for safely shutting down the plant from outside the control room, including use of the ASSS.

The CDF contribution from fires assumed in the SAMA analysis has not been adjusted for these procedural and administrative improvements.

All of the fire zones shown in Table E.1-11, with the exception of the service water and circulating water pump areas, contain fire detection and manual fire suppression capability (i.e., through hose stations and portable fire extinguishers). In addition, the cable spreading room is equipped with a manually actuated total flooding Halon fire suppression system and the adjacent cable tunnel contains a closed head, pre-action, sprinkler system. All zones are regularly inspected by operations personnel who are trained fire brigade members, as well as by plant security officers. Given the procedural and administrative enhancements already implemented and the inherent complexity, substantial cost and competing risks associated with retrofitting possible fire suppression system designs, no further cost-effective changes were identified to reduce CDF in these zones.

E.1.3.3 Other External Hazards

The IP2 IPEEE submittal, in addition to the internal fires and seismic events, examined a number of other external hazards:

- high winds and tornadoes;
- external flooding; and
- ice, hazardous chemical, transportation, and nearby facility incidents.

The examination of IP2 utilized the NUREG-1407-recommended progressive screening approach for high winds, external flood, and transportation and nearby facility accidents. With the exception of high winds, these events were screened from further consideration using the NUREG-1407 guidance. Therefore, these other external event hazards are not included in this attachment and are not expected to impact the conclusions of this SAMA evaluation.

The IPEEE also applied and evaluated Generic Letter 89-22 probable maximum precipitation criterion as requested by NUREG-1407 to address Generic Issue 103. Although the evaluation did not result in quantification of the risk associated with these events, several suggested enhancements were implemented, including addition of a drain flapper valve to the surveillance program, addition of weather stripping to an exterior door, and placement of screens on 480V switchgear room hub drains.

E.1.3.3.1 High Wind Analysis

IP2 structures and systems were designed to the wind loading requirements of the building codes in effect in the early 1970s. They pre-date and do not meet the 1975 Standard Review Plan criteria. Therefore, utilizing the NUREG-1407 screening approach, it was concluded that a detailed probabilistic risk assessment was needed to address the impact of high wind events at IP2.

The wind hazard and building fragility analysis performed for the Indian Point Probabilistic Safety Study [Reference E.1-25] was reviewed and updated as necessary. An event tree was used to define a set of unique wind induced PDS. The CDF resulting from each wind induced PDS was quantified by modifying the internal event plant logic model, accounting for the frequency of each damage state and the wind-induced equipment damage.

Conservative assumptions in the high wind PSA analysis included the following.

- Offsite power was assumed to be lost for all high wind events.

- Building frame failures were assumed to cause failure of all equipment within the building.

- Missile (high wind projectile) impact on a structure was assumed to cause failure of all equipment within that structure.

- Likelihood of missile (high wind projectile) strikes was assumed to be independent of the intensity of the hazard.
- Both onsite and offsite alternate power sources (gas turbines) were assumed to fail given failure of a more robust structure.

The conclusions of the IP2 high wind PRA were as follows.

- The total point estimate wind induced CDF for IP2 is 3.03×10^{-5} per year.
- Sequences associated with structural failures are the dominant contributors to the wind risk profile.
- No vulnerabilities which could cause early failures of containment or containment bypass were identified.

The major contributors to wind risk at IP2 are major structural failures rather than component failures. Thus, as described in Table E.2-1 items 214, 227 and 228, insights from the IPEEE and PSA updates show that IP2 could decrease the CDF following SBO and unavailability of the gas turbines by aligning the IP3 Appendix R diesel, by installing an IP2 Appendix R diesel, by upgrading the EDG building, and by protecting the alternate power source from tornados and high winds. Aligning the IP3 Appendix R diesel, installing an IP2 Appendix R diesel, and hardening the alternate power source were not evaluated in Phase II SAMAs because, as discussed in Section E.1.4.3, a modification to replace the existing gas turbines with an IP2 Appendix R diesel is planned for the near future. This modification includes provisions for aligning the IP3 Appendix R diesel and for protecting the new alternate power source from tornados and high winds. Potential upgrade of the EDG building was evaluated in Phase II SAMA 066 . Given the substantial cost and complexity of major structural changes, no further cost-effective changes to reduce wind risk were identified.

Since the time of the high wind PRA, one of the gas turbines has been removed from service. Although this change has been incorporated in the Level 1 PSA model, it is not reflected in the IPEEE wind risk value of 3.03×10^{-5} since the IPEEE is not a living model. Although removal of this gas turbine reduces the probability of recovering power from the offsite gas turbine location, the impact on the IPEEE high wind risk contribution has been off-set by improvement in the availability of the remaining offsite gas turbine. Also, as discussed in Section 4.21, qualitative assessment of conservatisms in the high wind model and changes within the Level 1 PSA model that have caused internal event CDF to decrease 43% since the IPE shows that the IPEEE wind risk contribution is conservative. Therefore, the IPEEE wind risk contribution of 3.03×10^{-5} per year was used to determine the external events multiplier described in Section 4.21.5.4.

Table E.1-11
IP2 Fire Updated CDF Results

Fire Zone	Fire Zone Description	CDF/year	New Estimate CDF/year
1A	electrical tunnel / pipe penetration area	9.19×10^{-7}	6.55×10^{-7}
2A	primary water makeup area	1.05×10^{-6}	5.13×10^{-7}
11	cable spreading room	4.28×10^{-6}	2.04×10^{-6}
14	switchgear room	3.84×10^{-6}	1.40×10^{-6}
15	control room	7.07×10^{-6}	1.43×10^{-6}
74A	electrical penetration area	1.11×10^{-6}	2.97×10^{-7}
6A*	drumming and storage station	1.53×10^{-9}	1.53×10^{-9}
32A*	cable tunnel	9.62×10^{-8}	9.62×10^{-8}
1*	CCW pump room	2.19×10^{-9}	2.19×10^{-9}
22/63A*	service water intake	7.46×10^{-9}	7.46×10^{-9}
23*	AFW pump room	6.15×10^{-9}	6.15×10^{-9}

* Note: These fire zones had no sequences with CDF contribution greater than 1×10^{-7} and were conservatively not re-evaluated.

E.1.4 PSA Model Revisions and Peer Review Summary

The summary of the IP2 PSA models CDF and LERF is presented in the table below.

Summary of Major PSA Models		
Model	**CDF (/ry)**	**LERF (/ry)**
IPE (8/1992)	3.13E-5[1]	N/A[2]
RISKMAN Model (5/2003)	2.19E-5	1.27E-6
Revision 0 (3/2005)	1.71E-5	1.05E-6
Revision 1 (3/2007)	1.79E-5	6.50E-7

1. The IP2 IPE did not include internal flooding, which was examined as part of the IPEEE
2. The IP2 IPE did not provide a LERF value since the use of LERF as a risk metric post dates the IPE

E.1.4.1 Major Differences between the IP2 Revision 0 PSA Model and Original IPE Model

The IP2 risk model has undergone both updates and a change from RISKMAN to CAFTA since the IPE was performed. The changes implemented prior to the change from RISKMAN to CAFTA are described in Section E.1.4.3.

In the IPE model, the contributors in order of dominance were transients (41.40 percent), LOCAs (33.30 percent), SBO (14.26 percent), SGTR (5.98 percent), ATWS (5.78 percent), and ISLOCA (0.09 percent). As noted previously, the internal flooding analysis was done separately in the IPEEE.

In the final RISKMAN model (following the WOG peer review), the contributors in order of dominance were internal flooding (29.71 percent), LOCA (20.08 percent), loss of offsite power (19.37 percent), ATWS (14.09 per cent), transients (5.61 percent), loss of CCW (4.14 percent), SGTR (3.57 percent), vessel rupture (1.37 percent), loss of DC power (1.11 percent), loss of non-essential service water (0.42 percent), ISLOCA (0.32 percent), and total loss of service water (0.20 percent).

The Revision 0 PSA model [Reference E.1-2] CDF (1.71E-5/ry) represents a slight reduction from the CDF determined from the final RISKMAN model (2.19E-5/ry).

In the Revision 0 PSA model, the contributors in order of dominance were loss of offsite power (31.48 percent), internal flooding (28.96 percent), LOCA (7.53 percent), transients (7.53 percent), ATWS (5.75 percent), SGTR (4.57percent), total loss of service water (4.01 percent), SBO (3.80 percent), loss of CCW (3.10 percent), loss of non-essential service water (1.83 percent), vessel rupture (0.58 percent), ISLOCA (0.58 percent), and loss of 125 VDC power (0.26 percent).

Significant changes were made during the conversion and development of the Revision 0 PSA model. Changes were made to reflect new data, calculations, and modifications to the plant design and procedures. The major model changes impacting CDF and LERF that were incorporated into the IP2 PSA Revision 0 model can be summarized as follows.

Level 1 - Core Damage Model

- Updated initiating event database, including all IP2 plant trips that occurred between 1/1/1986 and 12/31/2003.

- Updated component failure data base that reflects failures that occurred between 2/1/1991 and 12/31/2003, and unavailability data base occurred between 7/1/1993 and 12/31/2003, more equipment groups in which common-cause failures may occur and current on-line maintenance practices.

- Revised HRA to reflect the EOP changes up to 12/31/2003.

- Revised internal flooding analysis to reflect design and procedure modifications.

- Adopted the linked fault tree approach versus the support-state model used in RISKMAN. While RISKMAN uses a large-event-tree/small-fault-tree approach to quantification, the IP2 PSA Revision 0 uses the CAFTA small-event-tree/large-fault-tree approach.

- Provided a more detailed modeling of instrumentation and control systems.

- Utilized MAAP thermal-hydraulic calculations based on a reactor thermal output power level of 3216 MWt (versus 3071.4 MWt) to reflect the IP2 power uprate obtained in 2003 and the stretch power uprate project.

- Incorporated the Improved Technical Specifications issued in 2003.

- Revised initiating event definitions and grouping to that used for other ENN models.

- Revised common-cause component failure modeling to the Alpha method (versus the Multiple-Greek-Letter method used in the previous update). The Alpha method is a more recent method that has been approved by the NRC and used in the NRC plant Standardized Plant Assessment Risk models.

- Updated HRA method to reflect the most recent version of the EPRI HRA method and incorporate improvements in the performance shaping factors and inter-action dependency.

- Updated generic component failure database based on EGG-SSRE-8875 failure rates. The generic data used in the previous model was based on a proprietary database obtained from PLG.

- Updated RCP seal LOCA model to that documented in WCAP-16141, which was approved for use by NRC and is also referred to as the WOG2000 RCP seal LOCA model. The RCP seal LOCA model used in the previous model was based on a previous version of the WOG RCP seal LOCA model, so some differences existed in failure probabilities and timing. In addition, core uncovery times used to model RCP seal LOCAs were revised based on plant-specific MAAP runs.

- Updated offsite power recovery data using information contained in EPRI report 1009889, which contains data through 2003. The previous model was based on NUREG/CR-5496 and only included loss of offsite power events through 1996.

- Added event trees for loss of primary coolant events that remain within the capability of the charging system (i.e. small-small LOCAs), RCP seal LOCAs caused by random mechanical failures, loss of essential service water, and additional ISLOCA break locations.

Specific changes to reflect WOG peer review recommendations included the following.

- Revised internal flooding analysis, including estimates of pipe-break frequencies and human error probabilities.

- Updated ISLOCA analysis to address specific pathways, to specifically address ISLOCAs inside containment, to credit mitigating systems only for small LOCAs outside containment, to remove credit for makeup to the RWST and to reduce the break size screening criterion to one inch or less consistent with the approach in NUREG/CR-5744.

Level 2 - Containment Performance Model

As part of the conversion process, the Level 2 analysis was re-done using the more detailed methodology employed earlier for Indian Point Unit 3 (IP3).

The new containment response analysis entailed the following.

- Identifying and describing key highlights of component, system, and structure data of significance in assessing severe accident progressions.

- Applying MAAP 4.0 plant analytical models and the selection of empirical factor and data inputs.

- Reviewing the PDS that characterize the RCS, containment, and core-cooling systems at the start of core damage.

- Characterizing the containment strength assessment and the magnitude of various loads necessary to fail containment.
- Selecting a CET that models various accident scenarios in terms of system capability and human interaction to arrest core damage and prevent an undesirable outcome, given the sets of initial conditions defined by the various PDS.
- Characterizing radionuclide releases by associating each CET end state that was found to have a significant frequency with a specific source term.
- Developing the LERF model.
- Describing the methods and the results of the CET probabilistic analyses (quantification), and the source term numerical results and insights.
- Performing sensitivity studies to evaluate the effects on containment performance of changes in phenomena and changes to plant hardware and operating procedures.

There were no specific IP2 Level 2 WOG peer review issues, other than the ISLOCA issue discussed above, that needed to be addressed during the conversion to the fault tree linking platform. The major Level 2 issue from the IP3 WOG peer review, consideration of the predicted CsI release fraction in the assignment of sequences to release categories, was resolved in both the IP3 Revision 1 and the IP2 Revision 0 models.

E.1.4.2 Major Differences between the IP2 Revision 1 PSA Model and Revision 0 PSA Model

Quantification of the IP2 Revision 1 PSA model [Reference E.1-3] resulted in a slightly higher CDF than Revision 0 (i.e., 1.79E-5/ry for Revision 1 vs. 1.71E-5/yr for Revision 0). Major changes impacting CDF and LERF are summarized as follows.

Level 1 - Core Damage Model

- Included common cause terms for MOVs associated with hot-leg recirculation.
- Revised model to reflect the fact that normal offsite power feeds to the 480VAC safeguards buses do not trip on a SI signal without a concurrent loss of offsite power.
- Updated several initiating event frequencies including loss of offsite power, turbine trip, loss of main feedwater, main steam line break, and SGTR using data through the end of 2005.
- Updated the frequency for total loss of service water to reflect updated NRC component-specific common cause alpha factors for service water pumps. Previously, the model used generic alpha factors for motor-driven pumps.

- Added common-cause plugging of service water pump strainers.

- Updated common cause treatment of the main steam atmospheric relief valves to incorporate the latest Alpha factors from the NRC website.

- Added credit for Unit 1 station air compressors for non-loss of offsite power scenarios.

- Revised success criterion for the AFW system to require flow to two (rather than one) of four steam generators for normal (non-ATWS) response. In addition, the normal position of motor-driven AFW pump flow control valves was changed from open to closed.

- Updated offsite power recovery model based on data contained in NUREG/CR-6890, which provides loss of offsite power data from 1986 to 2004. The offsite power recovery model used in Rev. 0 was based on data contained in EPRI report 11009889, which only contains data through 2003.

Level 2 - Containment Performance Model

- Introduced ten additional PDS to better facilitate transfer of Level 1 information into the Level 2 containment performance analysis.

- Changed definition of high releases to "greater than 10% CsI released," which is consistent with the current industry definition. The previous definition was based on CsI releases greater than 1%.

- Changed some of the containment event tree release category magnitude endstate values (e.g., a number of endstates previously classified as late medium releases were reclassified as late high releases) based on the updated accident progression analysis.

E.1.4.3 PSA Model Peer Review

The original IPE submittal was based on a DOS version of the IP2 RISKMAN support state PSA model that used an equation format for system modeling. That submittal did not include evaluation of internal flooding events, which were subsequently included in the IPEEE analysis. Subsequent to the IPE, the IP2 internal events model was converted from using system equations to fault trees and a limited number of asymmetries that were conservatively modeled in the IPE were eliminated. As a result, the internal event CDF at the time of the IPEEE was 2.85E-5. The CDF for the original IPE was 3.13E-5/ry. [Reference E.1-1] The CDF contribution from internal flooding, found during the IPEEE, was 6.66E-6/ry. The RISKMAN model was subsequently converted to the WINDOWS platform and modified to reflect plant changes and modeling improvements, including

- credit for feedwater or condensate recovery, where available,
- treatment of cross-header common cause for both the essential and non-essential service water headers,

- update of equipment performance and unavailability data,
- update and upgrade of the human error probabilities based on extensive thermal hydraulic calculations,
- incorporation of a more current RCP seal LOCA model, and
- inclusion of internal flooding events.

The model, including the above changes, was peer reviewed in May 2002 using the process adapted by the Westinghouse Owners Group (WOG) from the review process that was originally developed and used by the Boiling Water Reactor Owners Group and subsequently broadened to be an industry-applicable process, through the Nuclear Energy Institute Risk Applications Task Force. All of the technical elements were graded as sufficient to support applications requiring the capabilities of a grade 2, e.g., risk ranking applications. In addition, most of the elements were further graded as sufficient to support applications requiring the capabilities defined for grade 3, e.g., risk-informed applications supported by deterministic insights. Facts and Observation sheets documented the certification team's insights and potential level of significance. There were no Level A findings (for which immediate model changes would have been appropriate) from the peer review. Although a number of minor model corrections were made following the peer review, no significant changes were made to the model structure or underlying assumptions. The final version of the IP2 RISKMAN model was completed in May 2003. Quantification of that model resulted in a CDF of 2.19E-5/ry, again including internal flooding.

Subsequently, the IP2 model was converted from the support state RISKMAN model to a linked fault tree CAFTA model. That effort also included an update and a number of modeling changes for consistency with other Entergy Nuclear Northeast (ENN) risk models and changes in the state of the art. The conversion addressed the remaining issues and observations from the IP2 WOG Peer Review (i.e., Level B, C, and D observations), where appropriate. In addition, the issues raised during the peer review of the IP3 model were also examined for applicability to IP2. All applicable issues were addressed consistent with the treatment for IP3. Given the conversion of the model to the Entergy standard methodology and approach, and to assure consistency for future updates, the revised model was named the "IP2 PSA Model Revision 0" and issued in March 2005 [Reference E.1-2].

The individual work packages (event tree, fault tree, human reliability analysis (HRA), data, etc.) and internal flooding analysis developed for the Revision 0 PSA model were circulated to other PSA members for independent peer review. The work packages and internal flooding analyses were also provided to appropriate IPEC plant personnel for review. Additionally, the revised model was subjected to a focused self assessment to demonstrate technical quality in preparation for the Mitigating Systems Performance Indicator program in 2006. Also, the update was subjected to a week-long review by a team of industry peers from outside of the ENN staff in July 2005. All findings and recommendations from this peer review were resolved and incorporated in the IP2 Revision 1 PSA model issued in April 2007.

The model changes in the IP2 Revision 1 PSA model were peer reviewed for accuracy and consistency by members of the ENN staff not directly involved in their implementation. In addition, cognizant departments at IP2—licensing, operations, maintenance, training, planning & scheduling, system engineering, and design engineering—were provided with the final results and insights derived from the study for review prior to the issuance of the Revision 1 report.

In accordance with plant procedures, potential plant modifications, design change documents and emergency operating procedure changes are reviewed to determine their impact on the PSA model prior to implementation. A PSA model change request database is maintained to track potential changes and assess their degree of impact of the PSA model. As of December 2006, this database shows no outstanding changes since December 2005 due to modifications or procedure changes that could have a significant impact on the results of the PSA or the SAMA analysis.

A modification to replace the existing gas turbines with a diesel generator (IP2 SBO/Appendix R diesel) capable of being used to recover power to the vital buses following a station blackout is planned for the near future. The IP2 SBO/Appendix R diesel is not reflected in the PSA model used for the SAMA analysis. A sensitivity study showed that including the IP2 SBO/Appendix R diesel in the model in place of the gas turbines would decrease the internal events CDF by about 1%. The slight decrease in CDF is due to the increased reliability of the IP2 SBO/Appendix R diesel when compared with that of the gas turbines. The IPEEE external events model is not a living model subject to requantification. However, the increased reliability of the IP2 SBO/Appendix R diesel when compared with that of the gas turbines and the relative ruggedness of the planned location of the IP2 SBO/Appendix R diesel within the turbine building compared to that of the gas turbine location would result in an overall reduction in the external event risk contribution. Since the impact on internal events CDF is so slight, redistribution of the relative importance of failure events in the internal events Level 1 model from this modification is not expected to add events to Table E.1-2 that would be likely contributors for the identification of cost-beneficial SAMAs. Therefore, the Phase I analysis would not be impacted by this modification.

If the model had included the IP2 Appendix R diesel in place of the gas turbines, the benefit estimates for Phase II SAMAs enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events (SAMAs 024 through 031) may have been slightly less due to the difference in reliability. For the same reason, the benefit for SAMA 066 (harden the EDG building and fuel oil transfer pumps against tornados and high winds) may have been slightly less. The conclusion of the SAMA analysis for these SAMAs (except SAMA 028) is that the cost of implementation is greater than the benefit. Lowering the benefit would not alter this conclusion. The conclusion for SAMA 028, "Provide a portable diesel-driven battery charger," is that the benefit with uncertainty is greater than the cost of implementation. Therefore, SAMA 028 is retained for further evaluation. Since the impact on CDF is so slight, the benefit with uncertainty of SAMA 028 is not expected to decrease enough to alter the potentially cost-beneficial conclusion, and SAMA 028 is still retained for further evaluation. Thus, the results of the SAMA analysis would remain unchanged if the model included the IP2 Appendix R diesel in place of the gas turbines.

E.1.5 MACCS2 Model: Level 3 Analysis

E.1.5.1 Introduction

SAMA evaluation relies on Level 3 PRA results to measure the effects of potential plant modifications. A Level 3 PRA model using the most recent version (version 1.13.1) of MACCS2 [Reference E.1-6] was created for IP2. This model, which requires detailed site-specific meteorological, population, and economic data, estimates the consequences in terms of population dose and offsite economic cost. Risks in terms of population dose risk (PDR) and offsite economic cost risk (OECR) were also estimated in this analysis. Risk is defined as the product of consequence and frequency of an accidental release.

This analysis evaluates a base case to provide best-estimate consequences for postulated internal events. Instead of considering various emergency planning scenarios, the base case uses a conservative assumption of no evacuation.

PDR was estimated by summing over all releases the product of population dose and frequency for each accidental release. Similarly, OECR was estimated by summing over all releases the product of offsite economic cost and frequency for each accidental release. Offsite economic cost includes costs that could be incurred during the emergency response phase and costs that could be incurred through long-term protective actions.

E.1.5.2 Input

The following sections describe the site-specific input parameters used to obtain the offsite dose and economic impacts for cost-benefit analyses.

E.1.5.2.1 Projected Total Population by Spatial Element

The total population within a 50-mile radius of IP2 was estimated for the year 2035 for each spatial element by combining total resident population projections with transient populations. The 2035 county level resident projections were derived from the New York Statistical Information System from 2000 to 2030, the New Jersey Department of Labor and Workforce Development from 2000 to 2025, the Connecticut State Data Center from 2000 to 2020, and the Pennsylvania State Data Center from 2000 to 2020 using regression analysis [References E.1-15 through E.1-18). The 2035 transient population was assumed to be the 2004 transient to permanent population ratio multiplied by the extrapolated permanent population. The 2004 transient data were obtained from state tourism agencies. Table E.1-12 summarizes the estimated population distribution.

Table E.1-12
Estimated Population Distribution within a 50-mile Radius

Sector	0-10 miles	10-20 miles	20-30 miles	30-40 miles	40-50 miles	50-mile Total
N	12,488	22,955	30,654	39,620	51,057	156,774
NNE	14,952	28,140	39,917	56,226	67,213	206,448
NE	23,377	29,419	53,692	62,559	41,261	210,308
ENE	40,386	74,856	119,073	152,175	176,338	562,828
E	41,290	118,335	156,720	200,581	208,394	725,320
ESE	37,861	121,515	144,267	54,180	34,361	392,184
SE	41,873	111,946	87,735	236,426	379,990	857,970
SSE	12,197	98,326	481,703	1,380,249	1,218,170	3,190,645
S	20,621	135,211	1,164,596	3,732,339	3,164,306	8,217,073
SSW	30,318	202,605	395,389	922,649	1,034,467	2,585,428
SW	30,796	183,372	276,902	197,362	246,076	934,508
WSW	27,723	64,428	209,197	109,102	85,849	496,299
W	16,925	32,026	50,974	61,380	57,384	218,689
WNW	14,036	32,528	54,577	57,977	29,719	188,837
NW	13,421	32,572	54,557	24,046	22,317	146,913
NNW	12,286	31,660	32,569	27,599	34,374	138,488
Total	390,550	1,319,894	3,352,522	7,314,470	6,851,276	19,228,712

E.1.5.2.2 Land Fraction

The land fraction for each spatial element was estimated within the 50 mile radius area. The National Hydrography Dataset was used to estimate the extent of land and surface water coverage (Reference E.1-19).

E.1.5.2.3 Watershed Class

Watershed Index is defined by MACCS2 as areas drained by rivers (Class 1) or large water bodies (Class 2). For IPEC, no spatial elements were treated as large water bodies. Therefore, only one watershed class was assigned for the 50 mile zone surrounding IP2.

E.1.5.2.4 Regional Economic Data

Region Index

Each spatial element was assigned to an economic region, defined in this report as a county. Where a spatial element covers portions of more than one county, it was assigned to that county having the most area within the element.

Regional Economic Data

County level economic data were obtained from the United States Census of Agriculture for 2002 (Reference E.1-20).

VALWF: Value of Farm Wealth

MACCS2 requires an average value of farm wealth (dollars/hectare) for the 50-mile radius area around IPEC. The county-level farmland property value was used as a basis for deriving this value. VALWF is $50,071/hectare.

VALWNF: Value of Non-Farm Wealth

MACCS2 also requires an average value of non-farm wealth. The county-level non-farm property value was used as a basis for deriving this value. VALWNF is $163,631/person.

Other economic parameters and their values are shown below. The values were obtained by adjusting the economic data from a past census given as default values in Reference E.1-6 with the consumer price index of 195.3, which is the average value for the year 2005, as appropriate.

Variable	Description	Value
EVACST	Daily cost for a person who has been evacuated ($/person-day)	46.7
POPCST	Population relocation cost ($/person)	8640
RELCST	Daily cost for a person who is relocated ($/person-day)	46.7
CDFRM0	Cost of farm decontamination for the various levels of decontamination ($/hectare)	972 2160

Variable	Description	Value
CDNFRM	Cost of non-farm decontamination for the various levels of decontamination ($/person)	5184 13824
DLBCST	Average cost of decontamination labor ($/person-year)	60480
DPRATE	Property depreciation rate (per year)	0.2
DSRATE	Investment rate of return (per year)	0.12

E.1.5.2.5 Agriculture Data

The source of regional crop information is the 2002 Census of Agriculture (Reference E.1-20). The crops listed for each county within the 50-mile area were summed and mapped into the seven MACCS2 crop categories.

E.1.5.2.6 Meteorological Data

The MACCS2 model requires meteorological data for wind speed, wind direction, atmospheric stability, accumulated precipitation, and atmospheric mixing heights. The required data were obtained from the IPEC meteorological monitoring system and regional National Weather Service stations.

Site Specific Data

IPEC meteorological monitoring system includes both primary and backup systems. The primary meteorological system, which includes a 122 meter instrumented tower located onsite, was the data source for the MACCS2 analysis. Based on a review of annual meteorological data collected at the site between 1995 and 2004, five recent years of data were averaged and used for this study. The five-year data included 43,848 (two leap years) consecutive hourly values of wind speed, wind direction, precipitation, and temperature recorded at the IPEC meteorological tower from January 2000 to December 2004. Missing data were estimated using data substitution methods. These methods include substitution of missing data with valid data from the previous hour and substitution of valid data collected from other elevations on the meteorological tower.

Regional Mixing Height Data

Mixing height is defined as the height of the atmosphere above ground level within which a released contaminant will become mixed (from turbulence) within approximately one hour. Regional mixing heights were calculated using data collected at National Weather Service (NWS) Station No. 72503 in White Plains, NY (approximately 16 miles southeast of IP2) and NWS Station No. 54775 in Albany, NY (approximately 80 miles north of IP2). These two weather stations were the closest NWS sources of data for local and upper air conditions. Staff meteorologists at the National Climatic Data Center selected these two stations for data used to calculate seasonal mixing height values for the IP2 area.

E.1.5.2.7 Emergency Response Assumptions

A detailed analysis of evacuation scenarios in emergency planning zone (EPZ) were addressed in the IP2 evacuation travel time estimate study (Reference E.1-21). The study was conducted in 2004 and provides an analysis of the range and variation of public reaction to the evacuation notification process. Evacuation, which is considered as an effective measure for mitigating accident consequences, would reduce radiation dose received by population within the EPZ. The primary parameters affecting the evacuation consequences are evacuation speed and time elapsed to the start of evacuation. Either a lower speed of evacuation or a delayed evacuation would increase the received radiation dose. In turn, should no evacuation get initiated, the dose would be higher. For this study, a "no evacuation scenario" was assumed to conservatively estimate the population dose.

E.1.5.2.8 Core Inventory

The estimated IP2 core inventory (Table E.1-13) used in the MACCS2 input is based on current core configuration and a power level of 3216 MW (t).

Table E.1-13
IP2 Core Inventory (Becquerels)[1]

Nuclide	Inventory	Nuclide	Inventory
Co-58	3.04E+16	Te-131m	4.64E+17
Co-60	2.32E+16	Te-132	4.57E+18
Kr-85	3.84E+16	I-131	3.20E+18
Kr-85m	8.48E+17	I-132	4.64E+18
Kr-87	1.63E+18	I-133	6.56E+18
Kr-88	2.29E+18	I-134	7.19E+18
Rb-86	8.31E+15	I-135	6.11E+18
Sr-89	3.08E+18	Xe-133	6.28E+18
Sr-90	3.05E+17	Xe-135	1.67E+18
Sr-91	3.87E+18	Cs-134	7.19E+17
Sr-92	4.19E+18	Cs-136	2.10E+17
Y-90	3.18E+17	Cs-137	4.15E+17
Y-91	3.98E+18	Ba-139	5.83E+18
Y-92	4.19E+18	Ba-140	5.62E+18

Table E.1-13
IP2 Core Inventory (Becquerels)[1] (Continued)

Nuclide	Inventory	Nuclide	Inventory
Y-93	4.85E+18	La-140	6.04E+18
Zr-95	5.38E+18	La-141	5.34E+18
Zr-97	5.41E+18	La-142	5.17E+18
Nb-95	5.45E+18	Ce-141	5.31E+18
Mo-99	6.11E+18	Ce-143	4.96E+18
Tc-99m	5.34E+18	Ce-144	4.19E+18
Ru-103	4.89E+18	Pr-143	4.78E+18
Ru-105	3.36E+18	Nd-147	2.13E+18
Ru-106	1.71E+18	Np-239	6.56E+19
Rh-105	3.09E+18	Pu-238	1.44E+16
Sb-127	3.47E+17	Pu-239	1.22E+15
Sb-129	1.04E+18	Pu-240	1.83E+15
Te-127	3.43E+17	Pu-241	4.12E+17
Te-127m	4.50E+16	Am-241	4.92E+14
Te-129	1.02E+18	Cm-242	1.23E+17
Te-129m	1.50E+17	Cm-244	1.33E+16

1. Derived from Reference E.1-22 for a power level of 3216 MWth except for Co-58 and Co-60, which were power-scaled from the reference inventory given in Reference E.1-6.

E.1.5.2.9 Source Terms

Only eight of nine release categories given in Table E.1-9, corresponding to internal event sequences, were part of the MACCS2 input. The Early Low-Low category has zero release frequency and is not considered. Section E.1.2.2.7 provides details of the source terms for postulated internal events. A linear release rate was assumed between the time the release started and the time the release ended.

E.1.5.3 Results

Risk estimates for the base case were analyzed with MACCS2. The base case assumes no evacuation. Table E.1-14 shows estimated base case mean risk values for each release mode. The estimated mean values of PDR and offsite OECR for IP2 are 22 person-rem/yr and $44,900/yr, respectively.

Table E.1-14
Base Case Mean PDR and OECR Values

Release Mode	Frequency (/yr)	Population Dose (person-sv)[1]	Offsite Economic Cost ($)	Population Dose Risk (PDR) (person-rem/yr)	Offsite Economic Cost Risk (OECR) ($/yr)
NCF	1.19E-05	2.28E+01	5.16E+04	2.71E-02[2]	6.13E-01
EARLY HIGH	6.50E-07	1.58E+05	3.42E+10	1.03E+01	2.22E+04
EARLY MEDIUM	4.23E-07	4.86E+04	1.17E+10	2.06E+00	4.95E+03
EARLY LOW	1.11E-07	1.90E+04	3.06E+09	2.11E-01	3.40E+02
LATE HIGH	6.88E-07	4.23E+04	1.05E+10	2.91E+00	7.22E+03
LATE MEDIUM	3.43E-06	1.78E+04	2.84E+09	6.11E+00	9.75E+03
LATE LOW	6.43E-07	5.37E+03	5.25E+08	3.45E-01	3.38E+02
LATE LOW-LOW	5.82E-08	4.64E+03	4.60E+08	2.70E-02	2.68E+01
			Totals	**2.20E+01**	**4.49E+04**

1. 1 sv = 100 rem
2. 2.71E-02 (person-rem/yr) = 1.19E-05 (/yr) x 2.28E+01 (person-sv) x 100 (rem/sv)

E.1.6 References

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ATTACHMENT E.2

EVALUATION OF IP2 SAMA CANDIDATES

E.2 EVALUATION OF IP2 SAMA CANDIDATES

This section describes the generation of the initial list of potential SAMA candidates, screening methods, and the analysis of the remaining SAMA candidates.

E.2.1 SAMA List Compilation

A list of SAMA candidates was developed by reviewing industry documents and considering plant-specific enhancements not identified in published industry documents. Since IP2 is a conventional pressurized water reactor, considerable attention was paid to the SAMA candidates from SAMA analyses for other pressurized water reactor plants. Industry documents reviewed include the following.

- Calvert Cliffs Nuclear Power Plant SAMA Analysis [Reference E.2-1]
- H.B. Robinson Steam Electric Plant Unit No.2 SAMA Analysis [Reference E.2-2]
- Virgil C. Summer Nuclear Station SAMA Analysis [Reference E.2-3]
- Arkansas Nuclear One Unit 2 SAMA Evaluation [Reference E.2-4]
- Donald C. Cook Nuclear Plant SAMA Analysis [Reference E.2-5]
- Millstone Units 2 and 3 SAMA Analysis [Reference E.2-6]
- Joseph M. Farley Nuclear Plant SAMA Analysis [Reference E.2-7]
- Point Beach Nuclear Plant Units 1 and 2 SAMA Analysis [Reference E.2-8]
- Palisades Nuclear Plant SAMA Analysis [Reference E.2-28]

The above documents represent a compilation of most SAMA candidates developed from the industry documents. These sources of other industry documents include the following.

- Quad Cities SAMA Analysis [Reference E.2-9]
- General Electric ABWR severe accident mitigation design alternative (SAMDA) Analysis [Reference E.2-10]
- Limerick SAMDA cost estimate report [Reference E.2-11]
- NUREG-1437 description of Limerick SAMDA [Reference E.2-12]
- NUREG-1437 description of Comanche Peak SAMDA [Reference E.2-13]
- Tennessee Valley Authority (TVA) response to NRC's RAI on the Watts Bar SAMDA submittal [Reference E.2-14]
- TVA response to NRC's RAI on the Watts Bar Generic Letter 88-20 IPE for Severe Accident Vulnerabilities [Reference E.2-15]
- Westinghouse AP600 SAMDA [Reference E.2-16]
- NUREG-1462, Final safety evaluation report related to the certification of Combustion Engineering System 80+ design [Reference E.2-17]
- NUREG-0498, Final Environmental Statement related to the Operation of Watts Bar Nuclear Plant Units 1 and 2, Supplement 1, Section 7 [Reference E.2-18]
- NUREG-1560, Volume 2, NRC Perspectives on the IPE Program [Reference E.2-19]
- NUREG/CR-5474, Assessment of Candidate Accident Management Strategies [Reference E.2-20]

In addition to SAMA candidates from review of industry documents, SAMA candidates were obtained from plant-specific sources, such as the IP2 IPE and updates [References E.2-21, E.2-22 and E.2-23] and IPEEE [Reference E.2-24]. In the original IPE, PSA model updates, and IPEEE, several enhancements related to severe accident insights were recommended and implemented. These enhancements are included in the comprehensive list of Phase I SAMA candidates. Table E.2-1 lists the IPE, PSA model update, and IPEEE Phase I SAMA candidates and indicates which have been implemented, which have been incorporated in the model used for the SAMA analysis, and which have been retained for further evaluation in Phase II of the SAMA analysis. The current PSA was also used to identify plant-specific modifications for inclusion in the comprehensive list of SAMA candidates. The risk significant terms from the current PSA model were reviewed for similar failure modes and effects that could be addressed through a potential enhancement to the plant. The correlation between SAMAs and the risk significant terms are listed in Tables E.1-2 and E.1-5.

The comprehensive list contained a total of 231 Phase I SAMA candidates and is available in onsite documentation.

E.2.2 Qualitative Screening of SAMA Candidates (Phase I)

The purpose of the preliminary SAMA screening was to eliminate from further consideration enhancements that were not viable for implementation at IP2. Potential SAMA candidates were screened out if they modified features not applicable to IP2, if they had already been implemented at IP2, or if they were similar in nature and could be combined with another SAMA candidate to develop a more comprehensive or plant-specific SAMA candidate. During this process, 58 of the Phase I SAMA candidates were screened out because they were not applicable to IP2, 9 of the Phase I SAMA candidates were screened out because they were similar in nature and could be combined with another SAMA candidate, and 96 of the Phase I SAMA candidates were screened out because they had already been implemented at IP2, leaving 68 SAMA candidates for further analysis. The final screening process involved identifying and eliminating those items whose implementation cost would exceed their benefit as described below. Table E.2-2 provides a description of each of the 68 Phase II SAMA candidates. As described in Section 4.21.5.4, the "baseline benefit" values in this table represent the total SAMA benefits for both internal and external events.

E.2.3 Final Screening and Cost Benefit Evaluation of SAMA Candidates (Phase II)

A cost/benefit analysis was performed on each of the remaining SAMA candidates. If the implementation cost of a SAMA candidate was determined to be greater than the potential benefit (i.e., there was a negative net value) the SAMA candidate was considered not to be cost beneficial and was not retained as a potential enhancement.

The expected cost of implementation of each SAMA was established from existing estimates of similar modifications. Most of the cost estimates were developed from similar modifications considered in previously performed SAMA. In particular, these cost-estimates were derived from the following sources.

- Arkansas Nuclear One Unit 2 SAMA Analysis [Reference E.2-4]
- Calvert Cliffs SAMA Analysis [Reference E.2-1]
- Donald C. Cook SAMA Analysis [Reference E.2-5]
- Fort Calhoun Unit 1 SAMA Analysis [Reference E.2-25]
- Joseph M. Farley SAMA Analysis [Reference E.2-7]
- McGuire SAMA Analysis [Reference E.2-26]

The cost estimates did not include the cost of replacement power during extended outages required to implement the modifications, nor did they include contingency costs associated with unforeseen implementation obstacles. Estimates based on modifications that were implemented or estimated in the past were presented in terms of dollar values at the time of implementation (or estimation), and were not adjusted to present-day dollars. Therefore, the cost estimates were conservative.

The benefit of implementing a SAMA candidate was estimated in terms of averted consequences. The benefit was estimated by calculating the arithmetic difference between the total estimated costs associated with the four impact areas for the baseline plant design and the total estimated impact area costs for the enhanced plant design (following implementation of the SAMA candidate).

Values for avoided public and occupational health risk were converted to a monetary equivalent (dollars) via application of the NUREG/BR-0184 [Reference E.2-27] conversion factor of $2,000 per person rem and discounted to present value. Values for avoided offsite economic costs were also discounted to present value.

As this analysis focuses on establishing the economic viability of potential plant enhancement when compared to attainable benefit, detailed cost estimates often were not required to make informed decisions regarding the economic viability of a particular modification. Several of the SAMA candidates were clearly in excess of the attainable benefit estimated from a particular analysis case.

For less clear cases, engineering judgment on the cost associated with procedural changes, engineering analysis, testing, training, and hardware modification was applied to determine if a more detailed cost estimate was necessary to formulate a conclusion regarding the economic viability of a particular SAMA. Based on a review of previous submittals' SAMA evaluations and an evaluation of expected implementation costs at IP2, the following estimated costs for each potential element of the proposed SAMA implementation were used.

Type of Change	**Estimated Cost Range**
Procedural only	$25K-$50K
Procedural change with engineering required	$50K-$200K
Procedural change with engineering and testing/training required	$200K-$300K

Type of Change	Estimated Cost Range
Hardware modification	$100K to >$1000K

In most cases, more detailed cost estimates were not required, particularly if the SAMA called for the implementation of a hardware modification. Nonetheless, the cost of each unscreened SAMA candidate was conceptually estimated to the point where conclusions regarding the economic viability of the proposed modification could be adequately gauged. The cost benefit comparison and disposition of each of the 68 Phase II SAMA candidates is presented in Table E.2-2.

Bounding evaluations (or analysis cases) were performed to address specific SAMA candidates or groups of similar SAMA candidates. These analysis cases overestimated the benefit and thus were conservative calculations. For example, one SAMA candidate suggested installing a digital feedwater upgrade system. The bounding calculation estimated the benefit of this improvement by total elimination of risk due to loss of feedwater events (see analysis of Phase II SAMA 41 in Table E.2-2). This calculation obviously overestimated the benefit, but if the inflated benefit indicated that the SAMA candidate was not cost beneficial, then the purpose of the analysis was satisfied.

A description of the analysis cases used in the evaluation follows.

Diesel Powered RCP Seal Injection

This analysis case was used to evaluate the change in plant risk from providing an independent, diesel powered RCP seal cooling system. The plant modification involves installation of a two-inch pipe inside containment and the PAB, manual isolation valves, control valves, instrumentation to monitor flow, self-contained diesel generator outside the PAB, pump, instrumentation cables, four orifices, power cable to the pump, two filters, water source piping and valves, and containment penetration piping and instrumentation. It also requires revision of standard operating and emergency operating procedures; calculations for piping and support dead weight, electrical load, and instrumentation setpoints; additional procedures; and training. RCP seal cooling enhancements would add redundancy to RCP seal cooling, reducing CDF from loss of component cooling or service water or from a SBO event. A bounding analysis was performed by setting all consequential RCP seal LOCAs from all plant initiators to zero in the level 1 PDS model, which resulted in a baseline benefit of approximately $198,892. This analysis case was used to model the benefit of Phase II SAMA 001.

Non-Diesel Powered RCP Seal Injection

This analysis case was used to evaluate the change in plant risk from providing an independent RCP seal cooling system without dedicated diesel power backup. RCP seal cooling enhancements would add redundancy to RCP seal cooling, reducing CDF from loss of component cooling or service water or from a SBO event. A bounding analysis was performed by setting all consequential RCP seal LOCAs from non-SBO initiators to zero in the level 1 PDS model, which resulted in a baseline benefit of approximately $182,710. This analysis case was used to model the benefit of Phase II SAMA 002.

Additional CCW Pump

This analysis case was used to evaluate the change in plant risk from installing an additional CCW pump. An additional CCW pump reduces the probability of loss of component cooling leading to a RCP seal LOCA. A bounding analysis was performed by setting common cause failures of CCW pumps to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMA 003.

Service Water Pumps

This analysis case was used to evaluate the change in plant risk from providing a procedure to cross-tie service water pumps to reduce the frequency of loss of service water. A bounding analysis was performed by setting the loss of non-essential service water and loss of essential service water initiators to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $44,633. This analysis case was used to model the benefit of Phase II SAMA 004.

RHR Heat Exchangers

This analysis case was used to evaluate the change in plant risk by improving the ability to cool the RHR heat exchangers by implementing procedure and hardware modifications to allow manual alignment of the fire protection system. A bounding analysis was performed by setting the loss of CCW to the RHR heat exchangers to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $56,813. This analysis case was used to model the benefit of Phase II SAMA 005.

EDG Building Ventilation

This analysis case was used to evaluate the change in plant risk by adding a diesel building high temperature alarm to improve diagnosis of loss of diesel building room cooling events. A bounding analysis was performed by setting loss of diesel building ventilation to zero in the level 1 PSA model, which results in a baseline benefit of approximately $28,451. This analysis case was used to model the benefit of Phase II SAMA 006.

Filtered Containment Vent

This analysis case was used to evaluate the change in plant risk from installing a filtered containment vent to provide fission product scrubbing. A bounding analysis was performed by setting late containment overpressurization failure to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately $556,227. This analysis case was used to model the benefit of Phase II SAMA 007.

Molten Core Debris Removal

This analysis case was used to estimate the change in plant risk from providing a molten core debris cooling mechanism. The plant modification for a reactor cavity flooding system involves use of fire water as a supply, a run of 500 feet of 8-inch pipe to a 1000 gpm pump (similar to containment spray pump), and a run of 8-inch pipe from the pump spare piping penetration. A 1-inch mini-flow test line and instrumentation would be required for periodic testing. In addition, calculations would be required for pipe support, pump capacity, electric cable, electrical loading, flow, and instrumentation. Additional procedures and training for alignment would also be required. A bounding analysis was performed by setting containment failure due to core-concrete interaction to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately $1,697,309. This analysis case was used to model the benefit of Phase II SAMAs 008, 009, and 010.

Inert Containment

This analysis case was used to estimate the change in plant risk from providing a means to inert containment to prevent combustion of hydrogen and carbon monoxide gases. A bounding analysis was performed by setting containment failures due to hydrogen burns to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately $695,283. This analysis case was used to model the benefit of Phase II SAMA 011.

Containment Sprays

This analysis case was used to evaluate the change in plant risk from installing additional containment spray capability to provide containment pressure control. A bounding analysis was performed by setting the events for loss of containment spray to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMAs 012, 013, and 016.

Base Mat Melt-Through

This analysis case was used to evaluate the change in plant risk from increasing the depth of the concrete base mat to ensure base mat melt-through does not occur. A bounding analysis was performed by setting containment failure due to base mat melt-through to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately $392,631. This analysis case was used to model the benefit of Phase II SAMA 014.

Strengthen Containment

This analysis case was used to evaluate the change in plant risk from strengthening containment by constructed a building connected to primary containment that is maintained at a vacuum to provide a method to depressurize containment and reduce fission product release. The proposed plant modification involves construction of a building structurally strong enough to sustain an approximately 10 psi pressure differential. Vacuum pumps, piping (600 feet), electrical equipment, instrumentation, and containment penetrations would be required. A bounding analysis was performed by setting all energetic containment failure modes (DCH, steam explosions, late over-pressurization) to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately $1,496,904. This analysis case was used to model the benefit of Phase II SAMA 015.

Containment Liner Protection

This analysis case was used to evaluate the change in plant risk from constructing a barrier that provides containment liner protection from ejected core debris at high RCS pressure. The proposed plant modification involves installation of a 50 foot diameter, 70 foot high barrier made of stainless steel. A bounding analysis was performed by setting the probability of HPME and subsequent DCH at high RCS pressure to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately $368,091. This analysis case was used to model the benefit of Phase II SAMA 017.

Steam Generator Heat Removal

This analysis case was used to evaluate the change in plant risk from installing a highly reliable steam generator shell-side heat removal system that relies on natural circulation and stored water sources. The proposed plant modification involves installation of two 8-inch penetrations into each steam generator, eight lengths of 8-inch pipe and supports inside containment, eight containment penetrations, piping and supports outside of containment, a water storage tank (about 300,000 gallons), tank heater, and instrumentation. It would also require hydro testing, procedure revisions and training. This SAMA would provide an additional means to scrub fission product releases. A bounding analysis was performed by setting SGTR with loss of secondary-side cooling events to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $16,360. This analysis case was used to model the benefit of Phase II SAMA 018.

Secondary Side Pressure Capacity

This analysis case was used to evaluate the change in plant risk from increasing the secondary side pressure capacity to lower the occurrence of an unisolated SGTR. A bounding analysis was performed by eliminating failure to isolate the ruptured steam generator during a SGTR to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $1,144,727. This analysis case was used to model the benefit of Phase II SAMA 019.

SGTR Fission Product Scrubbing

This analysis case was used to evaluate the change in plant risk from routing the discharge from the main steam safety valves through a structure where water spray would condense the steam and scrub the fission products inventory. The proposed plant medication involves installation of four tanks (50 feet long with 20 spray nozzles) and 400 feet of city water piping and supports. Procedure revisions and training would also be required. A bounding analysis was performed by reducing SGTR accident progression source terms by a factor of 2, which resulted in a baseline benefit of approximately $126,787. This analysis case was used to model the benefit of Phase II SAMA 020.

ISLOCA Mitigation

This analysis case was used to evaluate the change in plant risk from installing additional pressure or leak monitoring instrumentation between the pressure isolation valves in ISLOCA pathways or submerging potential ISLOCA break points in water. A bounding analysis was performed by setting all ISLOCA initiators to zero in the level 1 PSA model which resulted in a baseline benefit of approximately $425,172. This analysis case was used to model the benefit of Phase II SAMAs 021 and 024.

ISLOCA Valves

This analysis case was used to evaluate the change in plant risk from reducing the probability of an ISLOCA by increasing the frequency of valve leak testing or adding redundant and diverse limit switches to each containment isolation valve. The increased valve leak testing involves testing of 24 safety-related valves in containment. To allow for testing of valves located inside containment during power operation, installation of a test connection for each valve with piping outside of containment and double containment isolation valves would be required. In addition, revised procedures and training would need to be developed. A bounding analysis was performed by reducing the ISLOCA initiator 50 percent in the level 1 PSA model, which resulted in a baseline benefit of approximately $212,586. This analysis case was used to model the benefit of Phase II SAMAs 022 and 023.

MSIV Design

This analysis case was used to evaluate the change in plant risk from improving MSIV design to decrease the likelihood of containment bypass scenarios. A bounding analysis was performed by setting MSIV failures to isolate a faulted or ruptured steam generator to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $28,629. This analysis case was used to model the benefit of Phase II SAMA 025.

DC Power

This analysis case was used to evaluate the change in plant risk from plant modifications that would increase the availability of Class 1E DC power (i.e., increasing battery capacity, using fuel cells, or improving DC bus load shedding). It was assumed that battery life could be significantly extended from the existing battery capacity. This enhancement would extend AFW steam-driven pump operability and allow more time for AC power recovery. A bounding analysis was performed by changing the time available to recover offsite power before local operation of the AFW steam-driven pump is required from 2 hours to 24 hours during SBO scenarios in the level 1 PSA model. This resulted in a baseline benefit of approximately $44,633. This analysis case was used to model the benefit of Phase II SAMAs 026, 027, and 029.

Alternate Battery Charger Capability

This analysis case was used to evaluate the change in plant risk from plant modifications to provide alternate battery charging capabilityby installing a portable diesel-driven battery charger. The proposed plant modification involves purchasing, installing and maintaining a diesel-driven generator to charge the 130VDC batteries. Safety-related quick disconnects would be used to charge the selected battery. The diesel generator would be installed in a weather enclosure outside the turbine or control building, requiring fire barrier penetration sealing. The location would be as close as possible to the batteries to decrease the power loss along the cable. Calculation of cable size would have to be performed. In addition, procedure development and training would be required. A bounding analysis was performed by setting failure to locally control the turbine-driven AFW pump to zero in the Level 1 PSA model. This resulted in a baseline benefit of approximately $420,459. This analysis case was used to model the benefit of Phase II SAMA 028.

AC Power Cross-Tie with IP3

This analysis case was used to evaluate the change in plant risk from a plant modification to create an AC power cross-tie with IP3 to improve AC power reliability. The proposed plant modification involves installation of two breakers and 1500 feet of cable, conduit and supports from the 480VAC switchgears. Procedure development and training would also be required. A bounding analysis was performed by setting loss of the gas turbines to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $52,724. This analysis case was used to model the benefit of Phase II SAMA 030.

EDG Alternate Engine Cooling

This analysis case was used to evaluate the change in plant risk from providing a redundant and diverse source of engine cooling for the EDGs, which would contribute to enhanced diesel reliability. A bounding analysis was performed by setting loss of the essential service water supply for diesel cooling to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $36,542. This analysis case was used to model the benefit of Phase II SAMAs 031 and 032.

Improve 118VAC System

This analysis case was used to evaluate the change in plant risk from plant modifications to convert under-voltage AFW and reactor protective system actuation signals from 2-out-of-4 to 3-out-of-4 logic. This would reduce the risk associated with inverter failure and would improve the availability of the 118VAC vital bus. A bounding analysis was performed by setting common cause failure of the 118VAC transformers to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMAs 033.

Low Pressure Injection System

This analysis case was used to evaluate the change in plant risk from plant modifications that would increase the availability of alternate low pressure injection (i.e., additional diesel-driven low pressure vessel makeup or modification of the diesel-driven fire pump). Use of the diesel-driven fire pump for low pressure injection requires installation of piping, valves and supports. Procedure development and training would also be required. A bounding analysis was performed by eliminating failure of the RHR system in the level 1 PSA model, which resulted in a baseline benefit of approximately $4,090. This analysis case was used to model the benefit of Phase II SAMAs 034 and 037.

High Pressure Injection System

This analysis case was used to evaluate the change in plant risk from plant modifications that would increase the availability of high pressure injection (i.e., installing a diesel-driven high pressure injection system or replacing two of the three motor-driven SI pumps with diesel-powered pumps). A bounding analysis was performed by setting failure of the SI system to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $24,450. This analysis case was used to model the benefit of Phase II SAMAs 035 and 039.

Automatic Recirculation Cooling Swap-Over

This analysis case was used to evaluate the change in plant risk from installing an automatic swap-over to recirculation cooling upon RWST depletion to enhance the reliability of ECCS suction. A bounding analysis was performed by setting failure to align recirculation cooling (internal and external) to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $81,086. This analysis case was used to model the benefit of Phase II SAMA 036.

Conserve RWST Water Inventory

This analysis case was used to evaluate the change in plant risk from extending RWST capability by throttling low pressure injection pump flow earlier in medium or large-break LOCAs. A bounding analysis was performed by setting failure to align recirculation cooling (internal and external) in large and medium LOCAs to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $20,360. This analysis case was used to model the benefit of Phase II SAMA 038.

Enhance RCS Depressurization

This analysis case was used to evaluate the change in plant risk from enhancing RCS depressurization to allow successful low pressure ECCS injection following a small LOCA and high pressure SI failure. A bounding analysis was performed by setting common cause failure of the steam generator atmospheric dump valves (ADVs) to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $142,968. This analysis case was used to model the benefit of Phase II SAMA 040.

Main Feedwater System Upgrade

This analysis case was used to evaluate the change in plant risk from installing a digital feedwater upgrade to reduce the probability of loss of main feedwater following a plant trip or from installing a motor-driven feedwater pump to enhance the availability of feedwater injection subsequent to MSIV closure. A bounding analysis was performed by setting the loss of main feedwater initiator to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $105,536. This analysis case was used to model the benefit of Phase II SAMAs 041 and 043.

Steam Generator Atmospheric Steam Dump Valve Enhancement

This analysis case was used to evaluate the change in plant risk in automating the backup nitrogen supply to the steam generator atmospheric steam dump valve (ADV). This would eliminate the need for local manual action to align nitrogen bottles for control air during a loss of offsite power. A bounding analysis was performed by setting the manual local action to align nitrogen supply for control air supply to the steam generator ADV to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $12,270. This analysis case was used to model the benefit of Phase II SAMA 042.

Alternate Water Sources to Steam Generators

This analysis case was used to evaluate the change in plant risk from providing emergency connections to use the fire water system as backup for steam generator inventory. The proposed modification involves installation of 500 feet of 6-inch pipe from the fire pump house to a new electric 800 gpm pump. The modification would also require heat tracing, valves, supports, breakers and cabling, procedure development and training. A bounding analysis was performed by setting failure of the turbine-driven AFW pump and failure of local operation of AFW during SBO to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $984,503. This analysis case was used to model the benefit of Phase II SAMA 044.

Install Large Pressurizer PORVs

This analysis case was used to evaluate the change in plant risk from installing larger capacity PORVs to allow successful feed and bleed cooling with one valve open. A bounding analysis was performed by modifying the number of PORVs required for RCS feed and bleed from 2-of-2 to 1-of-2 and reducing failure of the operator action for feed and bleed by a factor of 5 in the level 1 PSA model, which resulted in a baseline benefit of approximately $385,602. This analysis case was used to model the benefit of Phase II SAMA 045.

Diesel Power to Instrument Air Compressors

This analysis case was used to evaluate the change in plant risk from modifying emergency operating procedures to align emergency diesel power to the instrument air compressors. This enhancement allows increased reliability of instrument air following loss of offsite power. A bounding analysis was performed by setting failure of the instrument air system to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMA 046.

Independent Boron Injection System

This analysis case was used to evaluate the change in plant risk from installing an independent boron injection system to provide a redundant means to shut down the reactor during ATWS. A bounding analysis was performed by setting common cause failure of the boric acid transfer pumps to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMAs 047.

ATWS Overpressure Protection

This analysis case was used to evaluate the change in plant risk from installing a system of relief valves in the RCS to prevent equipment damage from a pressure spike during an ATWS. This enhancement would improve equipment availability after an ATWS. The proposed modification involves installation of additional safety valves, discharge lines to the pressurizer relief tank, acoustic monitoring, and RCS hydro capability. Procedure development and training would also be required. A bounding analysis was performed by setting the CDF contribution from RCS overpressurization during an ATWS to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $48,723. This analysis case was used to model the benefit of Phase II SAMA 048.

Control Room ATWS Mitigation

This analysis case was used to evaluate the change in plant risk from installing motor generator set trip breakers in the control room (SAMA 049) or providing the capability to remove power from the bus powering the control rods (SAMA 050). For SAMA 049, the proposed plant modification involves installation of two additional breakers, 300 feet of cable, conduit and supports. This modification also requires two penetrations of the control room boundary and resealing, procedure development and training. For SAMA 050, procedure changes and training would be required. These enhancements would reduce the CDF due to ATWS. A bounding analysis was performed by setting failure to trip the control rods motor generator sets to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $28,451. This analysis case was used to model the benefit of Phase II SAMAs 049 and 050.

Large Break LOCA

This analysis case was used to evaluate the change in plant risk from installing a digital large break LOCA protection system. The proposed plant modification involves installation of analog to digital converters, digital logic racks, and input into the emergency safeguard system logic relay racks. Procedure modifications and training would also be required. A bounding analysis was performed by setting the large break LOCA initiator to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMA 051.

Main Steam Line Break inside Containment

This analysis case was used to evaluate the change in plant risk from installing secondary side guard pipes up to the MSIVs. This enhancement would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. This SAMA would also guard against or prevent consequential multiple SGTRs following a main steam line break event. A bounding analysis was performed by setting the main steam line break initiators (inside and outside containment) to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $73,529. This analysis case was used to model the benefit of Phase II SAMA 052.

Pressurizer PORV Block Valves

This analysis case was used to evaluate the change in plant risk from changing the pressurizer PORV block valves from closed to open. This enhancement would reduce the CDF contribution from loss of secondary heat sink when bleed and feed is not available. A bounding analysis was performed by setting PORV block valve failure to open to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $377,512. This analysis case was used to model the benefit of Phase II SAMA 053.

480VAC Switchgear Room Flood Alarm

This analysis case was used to evaluate the change in plant risk from installing a flood alarm in the 480VAC switchgear room to reduce CDF following switchgear room flooding. The proposed modification involves installing a single alarm and spare wires from the switchgear room to the control room. Procedure revisions and training would also be required. A bounding analysis was performed by setting control building flooding initiator frequencies to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $1,722,733. This analysis case was used to model the benefit of Phase II SAMA 054.

High-Head Recirculation Cooling

This analysis case was used to evaluate the change in plant risk from hardware modifications to allow high-head recirculation from either RHR heat exchanger or from providing procedural guidance to allow high-head recirculation from either RHR heat exchanger. This enhancement would reduce the CDF contribution from transients and LOCAs. The proposed plant modification for SAMA 055 involves installation of an 8-inch pipe tee on the RHR heat exchanger 22 outlet, piping, a new MOV, controls and indications. A bounding analysis was performed by setting loss of high-head recirculation cooling from RHR heat exchanger 21 hardware failures to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMAs 055 and 058.

RHR Heat Exchanger Valves

This analysis case was used to evaluate the change in plant risk from keeping the RHR heat exchanger discharge MOVs normally open to reduce the CDF contribution from transients and

LOCAs. A bounding analysis was performed by setting RHR heat exchanger discharge MOV failure to open to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $44,633. This analysis case was used to model the benefit of Phase II SAMA 056.

Pressurizer PORV DC Power

This analysis case was used to evaluate the change in plant risk from plant modifications to provide a backup source of DC power for the PORVs. This enhancement would reduce the CDF contribution from loss of secondary heat sink and enhance feed and bleed availability. The proposed plant modification involves installation of an additional battery, inverter, charger and two transfer switches. Procedure revisions and training would also be required. A bounding analysis was performed by setting failure of DC power to the PORVs to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $40,721. This analysis case was used to model the benefit of Phase II SAMA 057.

AFW System Changes

This analysis case was used to evaluate the change in plant risk from re-installing the low pressure suction trip on the AFW pumps and enhancing procedures to respond to loss of the normal suction path. This enhancement would increase system availability following loss of the normal AFW suction path and would reduce the CDF contribution from SBO events. The proposed plant modification involves installing two pressure switches for AFW pumps 21 & 22. Procedure revisions and training would also be required. A bounding analysis was performed by setting the CDF contribution from the loss of normal suction path to the AFW system to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $20,360. This analysis case was used to model the benefit of Phase II SAMA 059.

Flood Protection from Stairwell 4 into 480VAC Switchgear Room

This analysis case was used to evaluate the change in plant risk from adding protection against flood propagation from stairwell 4 into the 480V switchgear room. The proposed plant modification involves installation of a reverse door swing, additional ductwork and a check valve. A bounding analysis was performed by setting the internal flood initiator from a break in fire protection piping in stairwell 4 to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $387,828. This analysis case was used to model the benefit of Phase II SAMA 060.

Flood Protection from Deluge Room into 480VAC Switchgear Room

This analysis case was used to evaluate the change in plant risk from adding protection against flood propagation from the deluge room into the 480V switchgear room. The proposed plant modification involves upgrading the deluge room and the inside door to fire barriers. A bounding analysis was performed by setting the internal flood initiator from a break in the 10-in fire protection piping in elevation 15-ft deluge room to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $853,187. This analysis case was used to model the benefit of Phase II SAMA 061.

Alternate Safe Shutdown System (ASSS) Power to SI Pump

This analysis case was used to evaluate the change in plant risk from plant modifications for a hard-wired connection to an SI pump from an ASSS power supply. This enhancement would reduce the CDF contribution from internal and external events that cause loss of power from the 480V vital buses. The proposed plant modification involves installation of 500 feet of cable and conduit, a breaker and transfer switches. A bounding analysis was performed by setting failure to align ASSS power to the high-head SI pumps and charging pumps subsequent to loss of power from vital 480VAC buses due to control building flooding initiators to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $273,489. This analysis case was used to model the benefit of Phase II SAMA 062.

RHR Pump Room Flood Protection

This analysis case was used to evaluate the change in plant risk from providing a water-tight door for additional protection of the RHR pumps against flooding from sources in the PAB. The proposed plant modification involves installation of a water-tight door, a drain pump and a check valve. A bounding analysis was performed by setting the internal flood initiators inside the PAB to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $36,542. This analysis case was used to model the benefit of Phase II SAMA 063.

CCW Heat Exchanger Alternate Cooling Supply

This analysis case was used to evaluate the change in plant risk from providing a backup cooling water source for the CCW heat exchangers. This enhancement would reduce the CDF contribution from loss of non-essential service water events. The proposed plant change involves use of backup service water pumps to cool the CCW heat exchangers. Piping and valves exist to implement this change; however, additional analysis would be required to ensure adequate cooling flow (electrical load and service water flow). In addition, procedure changes and training would be required. A bounding analysis was performed by setting the loss of non-essential service water initiator to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $36,542. This analysis case was used to model the benefit of Phase II SAMA 064.

Upgrade ASSS for RCP Seal Cooling

This analysis case was used to evaluate the change in plant risk from upgrading the ASSS to allow timely restoration of seal injection and cooling. This enhancement would reduce the CDF contribution from internal and external events that cause loss of power from the 480VAC vital buses. The proposed plant modification involves installation of 500 feet of multi-conductor cable to the control room, along with control room penetration and sealing. In addition, the modification requires control switches mounted in panels, seismic evaluations, and internal wiring. Procedure revisions and training would also be required. A bounding analysis was performed by setting the control building flooding initiators to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $1,722,733. This analysis case was used to model the benefit of Phase II SAMA 065.

Harden EDG Building

This analysis case was used to evaluate the change in plant risk from plant modifications to harden the EDG building and fuel oil transfer pumps against tornados and high winds. Since external events are not part of the internal event PSA model, a bounding analysis was performed by determining the risk associated with wind induced events that included loss of the EDG building from the IPEEE high wind model. Since these events would result in SBO conditions, that risk was added to the internal event SBO PDS to create a revised baseline CDF specifically for this SAMA. This appropriately accounts for the reduced likelihood of offsite power recovery for the scenario. Removal of this risk results in an 85% reduction from the higher SAMA-specific CDF and a baseline benefit of approximately $1,577,438. Since this modification mitigates high wind external events, the external event multiplier described in Section 4.21.5.4, which was still applied to this SAMA, provides additional conservatism in the baseline benefit value. This analysis case was used to model the benefit of Phase II SAMA 066.

Charging Pump Alternate Cooling

This analysis case was used to evaluate the change in plant risk from plant modifications to allow the primary water system to cool the charging pumps. This enhancement would reduce the effect of loss of CCW by providing an alternate means to cool the charging pumps and preserve seal injection after a loss of CCW. The proposed plant modification involves installation of two manual valves and 100 feet of piping per charging pump. Procedure revisions and training would also be required. A bounding analysis was performed by setting failure to align city water alignment to the charging pumps to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $8,091. This analysis case was used to model the benefit of Phase II SAMA 067.

Recirculation Pump Motor Alternate Cooling

This analysis case was used to evaluate the change in plant risk from providing an independent source of cooling for the recirculation pump motors to reduce CDF associated with loss of CCW events. The proposed plant modification involves connecting city water or primary water supply to the piping associated with the auxiliary component cooling pumps, including isolation valves and supports (~300 feet of piping). A discharge drain line, procedure development and training would also be required. A bounding analysis was performed by setting loss of CCW to the recirculation pumps to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $12,181. This analysis case was used to model the benefit of Phase II SAMA 068.

E.2.4 Sensitivity Analyses

Three sensitivity analyses were conducted to gauge the impact of assumptions upon the analysis. The benefits estimated for each of these sensitivities are presented in Table E.2-3.

A description of each sensitivity case follows:

Sensitivity Case 1: Years Remaining Until End of Plant Life

The purpose of this sensitivity case was to investigate the sensitivity of assuming a 28-year period for remaining plant life (i.e. eight years on the original plant license plus the 20-year license renewal period). The 20-year license renewal period was used in the base case. The resultant monetary equivalent was calculated using 28 years remaining until end of facility life to investigate the impact on each analysis case. Changing this assumption does not cause additional SAMAs to be cost-beneficial.

Sensitivity Case 2: Conservative Discount Rate

The purpose of this sensitivity case was to investigate the sensitivity of each analysis case to the discount rate. The discount rate of 7.0% used in the base case analyses is conservative relative to corporate practices. Nonetheless, a lower discount rate of 3.0% was assumed in this case to investigate the impact on each analysis case. Changing this assumption does not cause additional SAMAs to be cost-beneficial.

Sensitivity Case 3: Inclusion of Economic Losses Due to Tourism and Business

The purpose of this sensitivity case was to investigate the sensitivity of each analysis case to the inclusion of economic losses due to tourism and business. The MACCS2 economic model used for the base case analysis did not consider such losses. This sensitivity case assumed a loss of $208,838/person as opposed to $163,631/person in the affected region following a postulated severe accident. This increased the calculated offsite economic cost risk for the base case and for each SAMA under consideration. Since the benefit for each SAMA is estimated as the difference between the base case and the SAMA, the sensitivity case 3 benefit values (Table E.2-3) are the same or only slightly higher than the baseline benefit values. Therefore, changing this assumption does not cause additional SAMAs to be cost-beneficial.

E.2.5 References

E.2-1 Attachment (2), Appendix F - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report - Operating License Renewal Stage, Calvert Cliffs Nuclear Power, April 1998.

E.2-2 Appendix F, Severe Accident Mitigation Alternatives Analysis Submittal Related to Licensing Renewal Application for the H.B. Robinson Steam Electric Plant Unit No.2, June 2002.

E.2-3 Appendix E, Environmental Report, Appendix F, Severe Accident Mitigation Alternatives Analysis Submittal Related to Licensing Renewal Application for the Virgil. C. Summer Nuclear Station, August 2002.

E.2-4 Appendix E-Attachment E, Severe Accident Mitigation Alternatives Submittal Related to Licensing Renewal for the Arkansas Nuclear One - Unit 2, October 2003.

E.2-5 Appendix F - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report for License Renewal, Donald C. Cook Nuclear Plant, October 2003.

E.2-6 Appendix F and Appendix G - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report for Renewed Operating Licenses, Millstone Power Station, Units 2 and 3, January 2004.

E.2-7 Appendix D - Attachment F - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report - Application for License Renewal, Joseph M. Farley Nuclear Plant, September 2003.

E.2-8 Appendix E - Appendix F - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report - Application for Renewed Operating Licenses, Point Beach Nuclear Plant Units 1 and 2, February 2004.

E.2-9 Appendix F, Severe Accident Mitigation Alternatives Submittal Related to Licensing Renewal for the Quad Cities Nuclear Power Plant Units 1 and 2, January 2003.

E.2-10 General Electrical Nuclear Energy, Technical Support Document for the ABWR, 25A5680, Revision 1, January 18, 1995.

E.2-11 Cost Estimate for Severe Accident Mitigation Design Alternatives, Limerick Generating Station for Philadelphia Electric Company, Bechtel Power Corporation, June 22, 1989.

E.2-12 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*, Volume 1, 5.35, Listing of SAMDAs considered for the Limerick Generating Station, U.S. Nuclear Regulatory Commission, May 1996.

E.2-13 NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants,* Volume 1, 5.36, Listing of SAMDAs considered for the Comanche Peak Steam Electric Station, U.S. Nuclear Regulatory Commission, May 1996.

E.2-14 Letter from Mr. D. E. Nunn (TVA) to NRC Document Control Desk dated October 7, 1994, "Watts Bar Nuclear Plant (WBN) Units 1 and 2 - Severe Accident Mitigation Design Alternatives (SAMDA) - Response to Request for Additional Information (RAI) - (TAC Nos. M77222 and M77223)."

E.2-15 Letter from Mr. M. O. Medford (TVA) to NRC Document Control Desk dated September 1, 1992, "Watts Bar Nuclear Plant (WBN) Units 1 and 2 - Generic Letter (GL) 88-20 - Individual Plant Examination (IPE) for Severe Accident Vulnerabilities - Response - (TAC M74488)."

E.2-16 Letter from N. J. Liparulo (Westinghouse Electric Corporation) to NRC Document Control Desk, dated December 15, 1992, "Submittal of Material Pertinent to the AP600 Design Certification Review."

E.2-17 NUREG-1462, Final Safety Evaluation Report related to the Certification of CE System 80+ design, U.S. Nuclear Regulatory Commission, August 1994.

E.2-18 NUREG 0498, *Final Environmental Statement Related to the Operation of Watts Bar Nuclear Plant, Units 1 and 2*, Supplement No. 1, U.S. Nuclear Regulatory Commission, April 1995.

E.2-19 NUREG-1560, *Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance*, Volume 2, U.S. Nuclear Regulatory Commission, December 1997.

E.2-20 NUREG/CR-5474, *Assessment of Candidate Accident Management Strategies*, U.S. Nuclear Regulatory Commission, March 1990.

E.2-21 Indian Point 2 Nuclear Generating Station Individual Plant Examination of Internal Events (IPE) Report, August 1992.

E.2-22 IP-RPT-04-00230 "Indian Point Unit 2 Nuclear Power Plant Probabilistic Safety assessment Revision 0, March 2005.

E.2-23 IP-RPT-07-00230 "Indian Point Unit 2 Nuclear Power Plant Probabilistic Safety assessment Revision 1, April 2007.

E.2-24 Indian Point 2 Nuclear Generating Station Individual Plant Examination of External Events (IPEEE) Report, December 1995.

E.2-25 Appendix E, Appendix 5 - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report for License Renewal, Fort Calhoun Unit 1 Nuclear Station, January 2002.

E.2-26 Duke Power Company, Applicant's Environmental Report, Operating License Renewal Stage, Attachment K, "McGuire Nuclear Stations Severe Accident Mitigation Alternatives (SAMA) Analysis," Rev. 0, Charlotte, North Carolina, May 2001.

E.2-27 NUREG/BR-0184, *Regulatory Analysis Technical Evaluation Handbook*, U.S. Nuclear Regulatory Commission, January 1997.

E.2-28 Appendix E-Attachment E, Severe Accident Mitigation Alternatives Submittal Related to Licensing Renewal for the Palisades Nuclear Plant, March 2005.

Table E.2-1
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
201	Operator action: Trip RCPs following loss of CCW	This SAMA would reduce the potential for RCP seal damage due to pump bearing failure.	Already installed	This operator action is taken to reduce the potential for RCP seal damage due to pump bearing failure following loss of CCW. The IP2 procedure instructs the operators to trip the reactor and the RCPs if flow cannot be re-established within two minutes from the time it was lost. Therefore, this SAMA has already been implemented at IP2.	Yes
202	Operator action: Align backup city water cooling to charging pumps following loss of CCW	This SAMA would reduce the possibility of a large RCP seal LOCA following a loss of CCW.	Already installed	This operator action is taken to align backup city water cooling to charging pumps following a loss of CCW to preclude the possibility of a large RCP seal LOCA. The IP2 procedure instructs the operators to align charging pumps in manual at maximum speed and, if no CCW pumps can be started, align backup cooling from city water. Therefore, this SAMA has already been implemented at IP2.	Yes

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
203	Operator action: Manually control turbine-driven AFW pump after battery depletion	This SAMA would provide direction to manually control the turbine-driven AFW pump after battery depletion to control steam generator water level during SBO.	Already installed	This operator action is taken to align the turbine-driven AFW pump after battery depletion to control steam generator water level and prevent water from entering the turbine and failing the pump. The IP2 procedure instructs the operators to manually open the turbine-driven AFW pump flow control valves to control flow to the steam generators. Therefore, this SAMA has already been implemented at IP2.	Yes
204	Operator action: Align alternate safe shutdown equipment	This SAMA would align alternate safe shutdown equipment to reduce CDF following switchgear room flooding.	Already installed	This operator action is taken to align ASSS to reduce CDF following switchgear room flooding. The IP2 procedure instructs the operators to manually align 23 charging pump, 21 SI pump and 21 AFW pump to ASSS power. Therefore, this SAMA has already been implemented at IP2.	Yes

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
205	Operator action: Manually insert control rods (ATWS)	This SAMA would insert control rods to reduce CDF following ATWS.	Already installed	This operator action is taken to manually insert control rods for at least one minute prior to peak RCS pressure during ATWS. The IP2 procedure instructs the operators to manually trip the reactor and enter procedure FR-S.1. If a manual trip of the reactor is not successful, FR-S.1 directs the operator to manually insert control rods. Therefore, this SAMA has already been implemented at IP2.	Yes
206	Operator action: Perform early cooldown and depressurization (SGTR)	This SAMA would terminate leakage from RCS into the secondary prior to overfilling the ruptured steam generator.	Already installed	This operator action is taken to cool and depressurize the RCS following a SGTR to terminate leakage from RCS into the secondary prior to overfilling the ruptured steam generator. The IP2 procedure instructs the operators to perform cooldown and depressurize the RCS following a SGTR. Therefore, this SAMA has already been implemented at IP2.	Yes

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
207	Operator action: Perform late cooldown and depressurization (SGTR)	This SAMA would terminate leakage from RCS into the secondary prior to depleting RWST inventory following a SGTR.	Already installed	This operator action is taken to cool and depressurize the RCS to cold shutdown following a SGTR to terminate leakage from RCS into the secondary prior to depleting RWST inventory. The IP2 procedure instructs the operators to perform cooldown and depressurize the RCS following a SGTR. Therefore, this SAMA has already been implemented at IP2.	Yes
208	Operator action: Initiate emergency boration	This SAMA would initiate emergency boration to reduce CDF following ATWS.	Already installed	This operator action is taken to initiate emergency boration within 10 minutes following an ATWS event. The IP2 procedure instructs the operators to manually trip the reactor and enter procedure FR-S.1. If a manual trip of the reactor is not successful, FR-S.1 directs the operator to initiate emergency boration of the RCS. Therefore, this SAMA has already been implemented at IP2.	Yes

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
209	Operator action: Align low head ECCS recirculation	This SAMA would reduce the CDF contribution from LOCAs.	Already installed	This operator action is taken to align low head ECCS recirculation (internal and external) following the injection phase of ECCS to deliver flow to the RCS cold legs during a LOCA. The IP2 procedure instructs the operators to transfer to recirculation if RWST level decreases to less than 9.24 feet. Therefore, this SAMA has already been implemented at IP2.	Yes
210	Operator action: Align city water backup cooling to RHR and SI pumps following loss of CCW	This SAMA would reduce the CDF contribution from loss of CCW.	Already installed	This operator action is to align city water backup cooling to RHR and SI pumps following loss of CCW. The IP2 procedure instructs the operators to establish backup cooling to RHR and SI pumps. Therefore, this SAMA has already been implemented at IP2.	Yes
211	Operator action: Align primary water backup cooling to RHR and SI pumps following loss of CCW	This SAMA would reduce the CDF contribution from loss of CCW.	Already installed	This operator action is to align primary water backup cooling to RHR and SI pumps following loss of CCW. The IP2 procedure instructs the operators to establish backup cooling to RHR and SI pumps. Therefore, this SAMA has already been implemented at IP2.	Yes

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
212	Keep both pressurizer PORV block valves open	This SAMA would reduce the CDF contribution from loss of secondary heat sink when feed and bleed is not available.	Retain (Phase II SAMA 053)	Investigate the feasibility of operating with both pressurizer PORV block valves open. A significant contribution to CDF is caused by events involving total loss of secondary heat sink in which primary feed-and-bleed cooling is not possible because of the inability to open one of the block valves either due to loss of power or random failure of the valves. Considered for a final cost-benefit evaluation, this SAMA would involve procedure and hardware changes to keep both pressurizer PORV block valves open during normal operation.	No
213	Install flood alarm in the 480VAC switchgear room	This SAMA would reduce CDF following switchgear room flooding.	Retain (Phase II SAMA 054)	Investigate the feasibility of installing a flood alarm in the 480V switchgear room. For rupture of the 10-in fire protection line in the deluge room, credit was not given for operator action to mitigate the flood prior to reaching critical flood heights for the switchgear. Appropriate procedures would have to be modified to alert operations personnel to confirm switchgear room conditions upon a fire pump start without a heat or smoke detector alarm, which would be indicative of a rupture of the fire protection piping.	No

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
214	Align IP3 Appendix R diesel to provide backup power to 6.9kV bus 5 or 6 following a SBO and unavailability of the gas turbines	This SAMA would reduce CDF following a SBO and unavailability of the gas turbines.	Already underway	The engineering evaluation and associated procedural changes to allow aligning the IP3 Appendix R diesel to provide backup power to IP2 6.9kV bus 5 or 6 following a SBO and unavailability of the IP2 Appendix R power source are already underway as part of the installation of the IP2 Appendix R diesel and replacement of the gas turbines.	No
215	Perform a hardware modification to allow high-head recirculation from either RHR heat exchanger	This SAMA would reduce the CDF contribution from transients and LOCAs.	Retain (Phase II SAMA 055)	Considered for a final cost-benefit evaluation, this modification would involve installing a piping connection from RHR heat exchanger 22 to the high-head recirculation header to enhance high-head recirculation capability during transients and LOCAs.	No
216	Keep RHR heat exchanger discharge MOVs normally open	This SAMA would reduce the CDF contribution from transients and LOCAs.	Retain (Phase II SAMA 056)	Considered for a final cost-benefit evaluation, this modification would involve a design modification to keep the RHR heat exchanger discharge MOVs normally open to enhance high pressure recirculation capability during transients and LOCAs.	No

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
217	Provide DC power backup for the PORVs	This SAMA would reduce the CDF contribution from loss of secondary heat sink and enhance feed and bleed availability.	Retain (Phase II SAMA 057)	Considered for a final cost-benefit evaluation, this modification would involve installing a DC power backup for the PORVs to improve the availability of the PORVs to perform the feed and bleed function during a loss of secondary heat sink.	No
218	Provide procedural guidance to allow high-head recirculation from either RHR heat exchanger	This SAMA would reduce the CDF contribution from transients and LOCAs.	Retain (Phase II SAMA 058)	Considered for a final cost-benefit evaluation, this SAMA would involve procedural changes to use the 22 RHR heat exchanger for high-head recirculation by opening both discharge MOVs and backfeeding through the 21 RHR heat exchanger outlet line.	No
219	Modify power dependencies to increase likelihood of successful high pressure recirculation	This SAMA would reduce the CDF contribution from transients requiring feed and bleed cooling.	Subsumed in Phase I SAMA 212	Swap the power supplies to the following sets of valves: MOVs 746 and 747, MOV 822A and 822B, HCV-638 & HCV-640. Based on power dependencies for those valves, this will increase the likelihood of successful high-head recirculation with feed and bleed cooling. Implementation of this SAMA would require keeping both pressurizer PORV block valves open. Therefore, this SAMA is subsumed in SAMA 212.	No

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
220	Provide added protection against flood propagation from stairwell 4 into the 480V switchgear room	This SAMA would reduce the CDF contribution from flood sources within stairwell 4 adjacent to the 480V switchgear room.	Retain (Phase II SAMA 060)	Considered for a final cost-benefit evaluation, this modification would involve installation of a reverse door swing, additional ductwork and a check valve.	No
221	Provide added protection against flood propagation from the deluge room into the 480V switchgear room	This SAMA would reduce the CDF contribution from flood sources within the deluge room adjacent to the 480V switchgear room.	Retain (Phase II SAMA 061)	Considered for a final cost-benefit evaluation, this modification would involve upgrading the deluge room and the inside door to fire barriers.	No

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
222	Provide a hard-wired connection to an SI pump from ASSS power supply	This SAMA would reduce the CDF contribution from internal and external events that cause loss of power from the 480V vital buses (SBO, control building floods and fires).	Retain (Phase II SAMA 062)	Considered for a final cost-benefit evaluation, this modification would involve installing cabling and a transfer switch to provide power from the ASSS power supply directly to at least one SI pump.	No
223	Provide a water-tight door for additional protection of the RHR pumps against flooding	This SAMA would reduce the CDF contribution from flood sources in the PAB.	Retain (Phase II SAMA 063)	Considered for a final cost-benefit evaluation, this modification would involve installing water-tight half height doors in the entrance to the RHR pump cubicles to allow flood water from PAB pipe ruptures to egress through the transformer yard door louvers at 19' elevation. A drain pipe and check valve would also be required.	No

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
224	Provide backup cooling water source for the CCW heat exchangers	This SAMA would reduce the CDF contribution from loss of non-essential service water events.	Retain (Phase II SAMA 064)	Considered for a final cost-benefit evaluation, the proposed plant change involves use of backup service water pumps to cool the CCW heat exchangers. Piping and valves exist to implement this change; however, additional analysis would be required to ensure adequate cooling flow (electrical load and service water flow).	No
225	Provide alternate source of water to the fan cooler units following loss of all service water	This SAMA would reduce the CDF associated with loss of essential service water.	Already Installed	Connections have been installed in the fan cooler service water inlet and outlet lines to allow connection of fire water, if available, following loss of the essential service water supply.	No

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
226	Upgrade the ASSS to allow timely restoration of seal injection and cooling.	This SAMA would reduce the CDF contribution from internal and external events that cause loss of power from the 480V vital buses (SBO, control building floods and fires).	Retain (Phase II SAMA 065)	Considered for a final cost-benefit evaluation, this modification would involve providing an automatic start and load feature (or manual start and load from the control room) for the ASSS power source.	No
227	Harden the EDG building and fuel oil transfer pumps against tornados and high winds	This SAMA would reduce the CDF contribution from high wind events that cause loss of offsite power.	Retain (Phase II SAMA 066)	Considered for a final cost-benefit evaluation, this modification would involve hardening the EDG building to meet 1975 Standard Review Plan design criteria for tornados and high winds.	No

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
228	Harden the alternate power sources against tornados and high winds	This SAMA would reduce the CDF contribution from high wind events that cause loss of offsite power.	Already underway	The design of the new IP2 alternate power source (Appendix R diesel generator) includes protection against tornados and high wind events.	No
229	Provide hardware connections to allow the primary water system to cool the charging pumps	This SAMA would reduce the effect of loss of CCW by providing an alternate means to cool the charging pumps and preserve seal injection after loss of CCW.	Retain (Phase II SAMA 067)	Considered for a final cost-benefit evaluation, this modification would involve installing the necessary connections and implementing procedure changes to allow primary water to supply cooling to the charging pumps on loss of CCW.	No

Table E.2-1 (Continued)
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
230	Provide independent source of cooling for the recirculation pump motors	This SAMA would reduce the CDF associated with loss of CCW.	Retain (Phase II SAMA 068)	Considered for a final cost-benefit evaluation, this modification would involve installing the necessary connections and implementing procedure changes to allow an alternate source (city water or primary water) to supply cooling to the recirculation pumps on loss of CCW.	No
231	Re-install the low pressure suction trip on the AFW pumps and enhance procedures to respond to loss of the normal suction path	This SAMA would reduce the CDF from loss of AFW due to loss of the normal suction path.	Retain (Phase II SAMA 059)	Considered for a final cost-benefit evaluation, this modification would re-install the low pressure suction trip to ensure that the pumps would be protected from loss of the normal suction path.	No

Table E.2-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Diesel Powered RCP Seal Injection 001 - Create an independent RCP seal injection system with a dedicated diesel.	Eliminate consequential RCP seal LOCAs from all plant initiators. The cost of implementing this SAMA was specifically estimated for IP2.	9.59%	1.82%	1.56%	$198,892	$418,719	$1,137,000	Not cost effective
Non-Diesel Powered RCP Seal Injection 002 - Create an independent RCP seal injection system without a dedicated diesel.	Eliminate consequential RCP seal LOCAs from non-SBO events. The cost of implementing this SAMA was specifically estimated for Donald C. Cook.	8.29%	1.82%	1.56%	$182,710	$384,653	$1,000,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Additional CCW Pump 003 - Install an additional CCW pump.	Eliminate common cause failure of CCW pumps. The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.	0.12%	0.00%	0.00%	~$0	~$0	$1,500,000	Not cost effective
Service Water Pumps 004 - Enhance procedural guidance for use of service water pumps.	Eliminate loss of non-essential service water and loss of essential service water initiators. The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.	1.88%	0.45%	0.22%	$44,633	$93,964	$1,750,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
RHR Heat Exchangers 005 - Improve ability to cool the RHR heat exchangers by allowing manual alignment of the fire protection system.	Eliminate loss of CCW to the RHR heat exchangers. The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	2.93%	0.45%	0.45%	$56,813	$119,607	$565,000	Not cost effective
EDG Building Ventilation 006 - Add a diesel building high temperature alarm.	Eliminate loss of EDG room ventilation. The cost of implementing this SAMA was specifically estimated for IP2.	1.13%	0.45%	0.22%	$28,451	$59,897	$274,000	Not cost effective
Filtered Containment Vent 007 - Install a filtered containment vent to provide fission product scrubbing.	Eliminate late containment over-pressurization failures. The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	0.00%	17.27%	13.36%	$556,227	$1,171,004	$5,700,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Molten Core Debris Removal	Eliminate containment failure due to CCI.	0.00%	48.18%	45.21%	$1,697,309	$3,573,283		
008 - Create a large concrete crucible with heat removal potential under the base mat to contain molten core debris.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						$108,000,000	Not cost effective
009 - Create a reactor cavity flooding system.	The cost of implementing this SAMA was specifically estimated for IP2.						$3,714,000	Not cost effective
010 - Create a core melt source reduction system.	The cost of implementing this SAMA was specifically estimated for Joseph M Farley.						$90,000,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Inert Containment 011 - Provide means to inert containment.	Eliminate containment failures due to hydrogen burns. The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	0.00%	17.73%	20.49%	$695,283	$1,463,754	$10,900,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Containment Sprays	Eliminate failure of containment spray.	0.00%	0.00%	0.00%	~$0	~$0		
012 - Use the fire protection system as a backup source for the containment spray system.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						$565,000	Not cost effective
013 - Install a passive containment spray system.	The cost of implementing this SAMA was specifically estimated for Joseph M Farley.						$2,000,000	Not cost effective
016 - Install a redundant containment spray system.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						$5,800,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Base Mat Melt-Through 014 - Increase the depth of the concrete base mat or use an alternative concrete material to ensure melt-through does not occur.	Eliminate containment failure due to base mat melt-through. The cost of implementing this SAMA was specifically estimated for Joseph M Farley.	0.00%	12.27%	9.35%	$392,631	$826,591	>$5,000,000	Not cost effective
Strengthen Containment 015 - Construct a building connected to primary containment that is maintained at a vacuum.	Eliminate energetic containment failure modes (DCH, steam explosion, late over-pressurization). The cost of implementing this SAMA was specifically estimated for IP2.	0.00%	41.36%	40.98%	$1,496,904	$3,151,377	$61,000,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Containment Liner Protection 017 - Erect a barrier that provides containment liner protection from ejected core debris at high pressure.	Eliminate HPME and subsequent DCH at high RCS pressure. The cost of implementing this SAMA was specifically estimated for IP2.	0.00%	10.00%	10.24%	$368,091	$774,929	$2,900,000	Not cost effective
Steam Generator Heat Removal 018 - Install a highly reliable steam generator shell-side heat removal system that relies on natural circulation and stored water sources.	Eliminate SGTR with loss of secondary-side cooling. The cost of implementing this SAMA was specifically estimated for IP2.	0.05%	0.45%	0.45%	$16,360	$34,441	$7,400,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Secondary Side Pressure Capacity 019 - Increase secondary side pressure capacity such that a SGTR would not cause the relief valves to lift.	Eliminate operator failure to isolate the ruptured steam generator. The cost of implementing this SAMA was specifically estimated for IP2.	2.42%	29.55%	31.18%	$1,144,727	$2,409,952	$13,000,000	Not cost effective
SGTR Fission Product Scrubbing 020 - Route the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove most of the fission products.	Reduce SGTR accident progression source terms by a factor of 2. The cost of implementing this SAMA was specifically estimated for IP2.	0.00%	3.64%	3.34%	$126,787	$266,920	$9,700,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
ISLOCA Mitigation	Eliminate ISLOCAs.	0.83%	10.91%	11.58%	$425,172	$895,098		
021 - Install additional pressure or leak monitoring instrumentation for ISLOCAs.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						$2,300,000	Not cost effective
024 - Ensure all ISLOCA releases are scrubbed.	The cost of implementing this SAMA was specifically estimated for IP2.						$9,700,000	Not cost effective
ISLOCA Valves	Reduce ISLOCAs by 50 percent.	0.40%	5.45%	5.79%	$212,586	$447,549		
022 - Add redundant and diverse limit switches to each containment isolation valve.	The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.						$1,000,000	Not cost effective
023 - Increase leak testing of valves in ISLOCA paths.	The cost of implementing this SAMA was specifically estimated for IP2.						$7,964,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
MSIV Design 025 - Improve MSIV design.	Eliminate MSIV failure to isolate a faulted or ruptured steam generator. The cost of implementing this SAMA was specifically estimated for IP2.	0.05%	0.91%	0.67%	$28,629	$60,272	$476,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
DC Power	Increase time available to recover offsite power before local operation of AFW is required from 2 hours to 24 hours during SBO scenarios.	1.94%	0.45%	0.22%	$44,633	$93,964		
026 - Provide additional DC battery capacity.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						>$1.875,000	Not cost effective
027 - Use fuel cells instead of lead-acid batteries.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						$2,000,000	Not cost effective
029 - Increase/ improve DC bus load shedding.	The cost of implementing this SAMA was specifically estimated for Fort Calhoun Unit 1.						>$160,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Alternate Battery Charger Capability 028 - Provide a portable diesel-driven battery charger.	Eliminate operator failure to locally control the turbine-driven AFW pump. The cost of implementing this SAMA was specifically estimated for IP2.	4.79%	10.00%	9.13%	$420,459	$885,176	$494,000	Retain
AC Power Cross-Tie with IP3 030 - Create AC power cross-tie capability with other unit.	Eliminate loss of the gas turbines. The cost of implementing this SAMA was specifically estimated for IP2.	2.81%	0.45%	0.22%	$52,724	$110,997	$1,156,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
EDG Alternate Engine Cooling	Eliminate loss of essential service water supply for EDG cooling.	1.69%	0.45%	0.22%	$36,542	$76,931		
031 - Create a backup source for diesel cooling (not from existing system).	The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.						$1,700,000	Not cost effective
032 - Use fire protection system as a backup source for diesel cooling.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						$497,000	Not cost effective
Improve 118VAC System 033 - Convert under-voltage AFW and reactor protective system actuation signals from 2-out-of-4 to 3-out-of-4 logic.	Eliminate common cause failure of the 118VAC transformers. The cost of implementing this SAMA was specifically estimated for IP2.	0.00%	0.00%	0.00%	~$0	~$0	$1,254,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Low Pressure Injection System	Eliminate failure of the RHR system.	0.02%	0.00%	0.22%	$4,090	$8,610		
034 - Provide capability for diesel-driven, low pressure vessel makeup.	The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.						$>632,000	Not cost effective
037 - Provide capability for alternate injection via diesel-driven fire pump.	The cost of implementing this SAMA was specifically estimated for IP2.						$750,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
High Pressure Injection System	Eliminate failure of the SI system.	0.29%	0.45%	0.45%	$24,450	$51,474		
035 - Provide an additional high pressure injection pump with independent diesel.	The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.						$5,000,000	Not cost effective
039 - Replace two of three motor-driven SI pumps with diesel-powered pumps.	The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.						$2,000,000	Not cost effective
Automatic Recirculation Cooling Swap-Over 036 - Create automatic swap-over to recirculation cooling upon RWST depletion.	Eliminate operator failure to align internal and external recirculation cooling. The cost of implementing this SAMA was specifically estimated for McGuire.	4.08%	0.45%	0.45%	$81,086	$170,707	$>1,000,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Conserve RWST Water Inventory 038 - Throttle low pressure injection pumps earlier in medium or large-break LOCAs to maintain reactor water storage tank inventory.	Eliminate operator failure to align internal and external recirculation cooling during a large or medium LOCA. The cost of implementing this SAMA was specifically estimated for IP2.	0.60%	0.45%	0.22%	$20,360	$42,864	$82,000	Not cost effective
Enhance RCS Depressurization 040 - Create/enhance a reactor coolant depressurization system.	Eliminate common cause failure of the steam generator ADVs. The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.	0.87%	3.18%	3.79%	$142,968	$300,986	$>1,000,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Main Feedwater System Upgrade	Eliminate loss of feedwater initiator.	4.85%	0.91%	0.89%	$105,536	$222,181		
041 - Install a digital feed water upgrade.	The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.						$900,000	Not cost effective
043 - Add a motor-driven feed water pump.	The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.						$2,000,000	Not cost effective
Steam Generator Atmospheric Steam Dump Valve Enhancement 042 - Provide automatic nitrogen backup to steam generator ADVs.	Eliminate failure of manual local action to align nitrogen supply for control air supply to the steam generator ADV control valve. The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	0.05%	0.45%	0.22%	$12,270	$25,831	$214,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Alternate Water Sources to Steam Generators 044 - Use fire water system as backup for steam generator inventory.	Eliminate failure of the turbine-driven AFW pump and failure of local operation of AFW during SBO. The cost of implementing this SAMA was specifically estimated for IP2.	33.00%	14.55%	13.36%	$984,503	$2,072,638	$1,656,000	Retain
Install Large Pressurizer PORVs 045 - Replace current pilot operated relief valves with larger ones such that only one is required for successful feed and bleed.	Change the number of PORVs required for RCS feed and bleed from 2-of-2 to 1-of-2. In addition, reduce failure of the operator action for feed and bleed by a factor of 5. The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	18.30%	3.64%	2.90%	$385,602	$811,795	$2,700,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Diesel Power to Instrument Air Compressors 046 - Modify emergency operating procedures for ability to align diesel power to more air compressors.	Eliminate failure of the instrument air system. The cost of implementing this SAMA was specifically estimated for IP2.	0.00%	0.00%	0.00%	~$0	~$0	$82,000	Not cost effective
Independent Boron Injection System 047 - Add an independent boron injection system.	Eliminate common cause failure of boric acid transfer pumps. The cost of implementing this SAMA was specifically estimated for Arkansas Unit-2.	0.00%	0.00%	0.00%	~$0	~$0	$300,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
ATWS Overpressure Protection 048 - Add a system of relief valves that prevent equipment damage from a pressure spike during an ATWS.	Eliminate RCS overpressurization during an ATWS. The cost of implementing this SAMA was specifically estimated for IP2.	1.98%	0.45%	0.45%	$48,723	$102,574	$615,000	Not cost effective
Control Room ATWS Mitigation	Eliminate failure to trip the control rod motor generator sets.	0.91%	0.45%	0.22%	$28,451	$59,897		
049 - Install motor generator set trip breakers in control room.	The cost of implementing this SAMA was specifically estimated for IP2.						$716,000	Not cost effective
050 - Provide capability to remove power from the bus powering the control rods.	The cost of implementing this SAMA was specifically estimated for IP2.						$90,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Large Break LOCA 051- Provide digital large break LOCA protection.	Eliminate large break LOCA initiator. The cost of implementing this SAMA was specifically estimated for IP2.	0.06%	0.00%	0.00%	~$0	~$0	$2,036,000	Not cost effective
Main Steam Line Break Inside Containment 052 - Install secondary side guard pipes up to the MSIVs.	Eliminate main steam line break initiators (inside and outside containment). The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.	0.45%	1.82%	1.78%	$73,529	$154,798	$1,100,000	Not cost effective
Pressurizer PORV Block Valves 053 - Keep both pressurizer PORV block valves open.	Eliminate failure of PORV block valves to open. The cost of implementing this SAMA was specifically estimated for IP2.	17.61%	3.64%	2.90%	$377,512	$794,761	$800,000	Not cost effective

**Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation**

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
480VAC Switchgear Room Flood Alarm 054 - Install flood alarm in the 480VAC switchgear room.	Reduce control building flooding initiator frequencies by a factor of 3. The cost of implementing this SAMA was specifically estimated for IP2.	19.97%	40.45%	38.31%	$1,722,733	$3,626,807	$200,000	Retain

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
High-Head Recirculation Cooling	Eliminate loss of high-head recirculation cooling due to RHR heat exchanger 21 hardware failures.	0.02%	0.00%	0.00%	~$0	~$0		
055 - Perform a hardware modification to allow high-head recirculation from either RHR heat exchanger.	The cost of implementing this SAMA was specifically estimated for IP2.						$1,330,000	Not cost effective
058 - Provide procedural guidance to allow high-head recirculation from either RHR heat exchanger.	The cost of implementing this SAMA was specifically estimated for IP2.						$82,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
RHR Heat Exchanger Valves 056 - Keep RHR heat exchanger discharge MOVs normally open.	Eliminate failure of RHR heat exchanger discharge MOVs to open. The cost of implementing this SAMA was specifically estimated for IP2.	1.84%	0.45%	0.22%	$44,633	$93,964	$82,000	Retain
Pressurizer PORV DC Power 057 - Provide DC power backup for the PORVs.	Eliminate failure of DC power to the PORVs. The cost of implementing this SAMA was specifically estimated for IP2.	1.22%	0.91%	0.45%	$40,721	$85,728	$376,000	Not cost effective
AFW System Changes 059 - Re-install the low pressure suction trip on the AFW pumps and enhance procedures to respond to loss of the normal suction path.	Eliminate loss of the normal suction path to the AFW system. The cost of implementing this SAMA was specifically estimated for IP2.	0.68%	0.45%	0.22%	$20,360	$42,864	$318,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Flood Protection from Stairwell 4 060 - Provide added protection against flood propagation from stairwell 4 into the 480VAC switchgear room.	Eliminate internal flood initiated by a break in fire protection piping in stairwell 4. The cost of implementing this SAMA was specifically estimated for IP2.	4.52%	9.09%	8.69%	$387,828	$816,481	$216,000	Retain
Flood Protection from Deluge Room 061 - Provide added protection against flood propagation from the deluge room into the 480V switchgear room.	Eliminate internal flood initiated by a break in the 10-in fire protection piping in elevation 15-ft deluge room. The cost of implementing this SAMA was specifically estimated for IP2.	9.84%	20.00%	18.93%	$853,187	$1,796,183	$192,000	Retain

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
ASSS Power to SI pump 062 - Provide a hard-wired connection to an SI pump from ASSS power supply.	Eliminate failure to align ASSS power to the high-head SI pumps and charging pumps subsequent to a loss of power from vital 480VAC buses due to control building flooding initiators. The cost of implementing this SAMA was specifically estimated for IP2.	3.08%	6.36%	6.01%	$273,489	$575,767	$722,000	Not cost effective
RHR Pump Room Flood Protection 063 - Provide a water-tight door for additional protection of the RHR pumps against flooding.	Eliminate internal floods initiated inside the PAB. The cost of implementing this SAMA was specifically estimated for IP2.	1.39%	0.45%	0.22%	$36,542	$76,931	$324,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
CCW Heat Exchanger Alternate Cooling Supply 064 - Provide backup cooling water source for the CCW heat exchangers.	Eliminate loss of non-essential service water initiator. The cost of implementing this SAMA was specifically estimated for IP2.	1.73%	0.45%	0.22%	$36,542	$76,931	$710,000	Not cost effective
Upgrade ASSS for RCP Seal Cooling 065 - Upgrade the ASSS to allow timely restoration of seal injection and cooling.	Eliminate control building flooding initiators. The cost of implementing this SAMA was specifically estimated for IP2.	19.97%	40.45%	38.31%	$1,722,733	$3,626,807	$560,000	Retain
Harden EDG Building 066 - Harden the EDG building and fuel oil transfer pumps against tornados and high winds.	Eliminate high wind induced failures of the EDG Building.	85.05%	9.09%	8.37%	$1,577,438	$3,320,922	>$10,000,000	Not cost effective

Table E.2-2 (Continued)
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Charging Pump Alternate Cooling 067 - Provide hardware connections to allow the primary water system to cool the charging pumps.	Eliminate failure to align city water to the charging pumps. The cost of implementing this SAMA was specifically estimated for IP2.	0.17%	0.00%	0.00%	$8,091	$17,033	$576,000	Not cost effective
Recirculation Pump Alternate Cooling 068 - Provide independent source of cooling for the recirculation pump motors.	Eliminate loss of CCW to the recirculation pumps. The cost of implementing this SAMA was specifically estimated for IP2.	0.27%	0.00%	0.22%	$12,181	$25,644	$710,000	Not cost effective

Table E.2-3
Sensitivity Analysis Results

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Diesel Powered RCP Seal Injection 001 - Create an independent RCP seal injection system with a dedicated diesel.	$198,892	$246,305	$236,665	$202,981	$1,137,000
Non-Diesel Powered RCP Seal Injection 002 - Create an independent RCP seal injection system without a dedicated diesel.	$182,710	$225,356	$218,908	$186,800	$1,000,000
Additional CCW Pump 003 - Install an additional CCW pump.	~$0	~$0	~$0	~$0	$1,500,000
Service Water Pumps 004 - Enhance procedural guidance for use of service water pumps.	$44,633	$55,546	$52,660	$44,633	$1,750,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
RHR Heat Exchangers 005 - Improve ability to cool the RHR heat exchangers by allowing manual alignment of the fire protection system.	$56,813	$70,570	$67,254	$56,813	$565,000
EDG Building Ventilation 006 - Add a diesel building high temperature alarm.	$28,451	$34,596	$34,903	$28,451	$274,000
Filtered Containment Vent 007 - Install a filtered containment vent to provide fission product scrubbing.	$556,227	$618,664	$777,247	$584,856	$5,700,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Molten Core Debris Removal	$1,697,309	$1,887,836	$2,371,747	$1,803,647	
008 - Create a large concrete crucible with heat removal potential under the base mat to contain molten core debris.					$108,000,000
009 - Create a reactor cavity flooding system.					$3,714,000
010 - Create a core melt source reduction system.					$90,000,000
Inert Containment	$695,283	$773,331	$971,559	$744,362	$10,900,000
011 - Provide a means to inert containment.					

Table E.2-3 (Continued)
Sensitivity Analysis Results

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Containment Sprays	~$0	~$0	~$0	~$0	
012 - Use the fire protection system as a backup source for the containment spray system.					$565,000
013 - Install a passive containment spray system.					$2,000,000
016 - Install a redundant containment spray system.					$5,800,000
Base Mat Melt-Through	$392,631	$436,704	$548,645	$408,990	>$5,000,000
014 - Increase the depth of the concrete base mat or use an alternative concrete material to ensure melt-through does not occur.					

Table E.2-3 (Continued)
Sensitivity Analysis Results

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Strengthen Containment 015 - Construct a building connected to primary containment that is maintained at a vacuum.	$1,496,904	$1,664,935	$2,091,709	$1,599,152	$61,000,000
Containment Liner Protection 017 - Erect a barrier that provides containment liner protection from ejected core debris at high pressure.	$368,091	$409,410	$514,355	$396,721	$2,900,000
Steam Generator Heat Removal 018 - Install a highly reliable steam generator shell-side heat removal system that relies on natural circulation and stored water sources.	$16,360	$18,196	$22,860	$16,360	$7,400,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Secondary Side Pressure Capacity 019 - Increase secondary side pressure capacity such that a SGTR would not cause the relief valves to lift.	$1,144,727	$1,280,604	$1,587,458	$1,234,705	$13,000,000
SGTR Fission Product Scrubbing 020 - Route the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove most of the fission products.	$126,787	$141,019	$177,167	$130,877	$9,700,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
ISLOCA Mitigation 021 - Install additional pressure or leak monitoring instrumentation for ISLOCAs. 024 - Ensure all ISLOCA releases are scrubbed.	$425,172	$475,850	$589,263	$461,981	 $2,300,000 $9,700,000
ISLOCA Valves 022 - Add redundant and diverse limit switches to each containment isolation valve. 023 - Increase leak testing of valves in ISLOCA paths.	$212,586	$237,925	$294,631	$228,945	 $1,000,000 $7,964,000
MSIV Design 025 - Improve MSIV design.	$28,629	$31,843	$40,005	$28,629	$476,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
DC Power	$44,633	$55,546	$52,660	$44,633	
026 - Provide additional DC battery capacity.					>$1.875,000
027 - Use fuel cells instead of lead-acid batteries.					$2,000,000
029 - Increase/ improve DC bus load shedding.					>$160,000
Alternate Battery Charger Capability 028 - Provide a portable diesel-driven battery charger.	$420,459	$480,938	$565,689	$440,908	$494,000
AC Power Cross-Tie with IP3 030 - Create AC power cross-tie capability with other unit.	$52,724	$66,021	$61,539	$52,724	$1,156,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
EDG Alternate Engine Cooling	$36,542	$45,071	$43,782	$36,542	
031 - Create a backup source for diesel cooling (not from existing system).					$1,700,000
032 - Use fire protection system as a backup source for diesel cooling.					$497,000
Improve 118VAC System	~$0	~$0	~$0	~$0	$1,254,000
033 - Convert under-voltage AFW and reactor protective system actuation signals from 2-out-of-4 to 3-out-of-4 logic.					

Table E.2-3 (Continued)
Sensitivity Analysis Results

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Low Pressure Injection System	$4,090	$4,549	$5,715	$4,090	
034 - Provide capability for diesel-driven, low pressure vessel makeup.					$>632,000
037 - Provide capability for alternate injection via diesel-driven fire pump.					$750,000
High Pressure Injection System	$24,450	$28,671	$31,739	$24,450	
035 - Provide an additional high pressure injection pump with independent diesel.					$5,000,000
039 - Replace two of three motor-driven SI pumps with diesel-powered pumps.					$2,000,000

**Table E.2-3 (Continued)
Sensitivity Analysis Results**

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Automatic Recirculation Cooling Swap-Over 036 - Create automatic swap-over to recirculation cooling upon RWST depletion.	$81,086	$101,994	$93,891	$81,086	>$1,000,000
Conserve RWST Water Inventory 038 - Throttle low pressure injection pumps earlier in medium or large-break LOCAs to maintain reactor water storage tank inventory.	$20,360	$24,122	$26,024	$20,360	$82,000
Enhance RCS Depressurization 040 - Create/enhance a reactor coolant depressurization system.	$142,968	$161,969	$194,924	$151,148	>$1,000,000

**Table E.2-3 (Continued)
Sensitivity Analysis Results**

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Main Feedwater System Upgrade 041 - Install a digital feed water upgrade. 043 - Add a motor-driven feed water pump.	$105,536	$130,665	$125,630	$105,536	 $900,000 $2,000,000
Steam Generator Atmospheric Steam Dump Valve Enhancement 042 - Provide automatic nitrogen backup to steam generator ADVs.	$12,270	$13,647	$17,145	$12,270	$214,000
Alternate Water Sources to Steam Generators 044 - Use fire water system as backup for steam generator inventory.	$984,503	$1,182,085	$1,232,516	$1,017,222	$1,656,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Install Large Pressurizer PORVs 045 - Replace current pilot operated relief valves with larger ones such that only one is required for successful feed and bleed.	$385,602	$477,587	$458,737	$393,782	$2,700,000
Diesel Power to Instrument Air Compressors 046 - Modify emergency operating procedures for ability to align diesel power to more air compressors.	~$0	~$0	~$0	~$0	$82,000
Independent Boron Injection System 047 - Add an independent boron injection system.	~$0	~$0	~$0	~$0	$300,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
ATWS Overpressure Protection 048 - Add a system of relief valves that prevent equipment damage from a pressure spike during an ATWS.	$48,723	$60,095	$58,375	$48,723	$615,000
Control Room ATWS Mitigation 049 - Install motor generator set trip breakers in control room. 050 - Provide capability to remove power from the bus powering the control rods.	$28,451	$34,596	$34,903	$28,451	 $716,000 $45,000
Large Break LOCA 051- Provide digital large break LOCA protection.	~$0	~$0	~$0	~$0	$2,036,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Main Steam Line Break Inside Containment 052 - Install secondary side guard pipes up to the MSIVs.	$73,529	$83,259	$100,320	$77,619	$1,100,000
Pressurizer PORV Block Valves 053 - Keep both pressurizer PORV block valves open.	$377,512	$467,112	$449,858	$385,691	$800,000
480VAC Switchgear Room Flood Alarm 054 - Install flood alarm in the 480VAC switchgear room.	$1,722,733	$1,969,241	$2,319,905	$1,808,621	$200,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
High-Head Recirculation Cooling 055 - Perform a hardware modification to allow high-head recirculation from either RHR heat exchanger. 058 - Provide procedural guidance to allow high-head recirculation from either RHR heat exchanger.	~$0	~$0	~$0	~$0	 $1,330,000 $82,000
RHR Heat Exchanger Valves 056 - Keep RHR heat exchanger discharge MOVs normally open.	$44,633	$55,546	$52,660	$44,633	$82,000
Pressurizer PORV DC Power 057 - Provide DC power backup for the PORVs.	$40,721	$48,243	$52,048	$44,811	$376,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
AFW System Changes 059 - Re-install the low pressure suction trip on the AFW pumps and enhance procedures to respond to loss of the normal suction path.	$20,360	$24,122	$26,024	$20,360	$318,000
Flood Protection from Stairwell 4 060 - Provide added protection against flood propagation from stairwell 4 into the 480VAC switchgear room.	$387,828	$443,169	$522,520	$408,278	$216,000
Flood Protection from Deluge Room 061 - Provide added protection against flood propagation from the deluge room into the 480V switchgear room.	$853,187	$975,523	$1,148,523	$898,176	$192,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
ASSS Power to SI pump 062 - Provide a hard-wired connection to an SI pump from ASSS power supply.	$273,489	$313,044	$367,601	$285,759	$722,000
RHR Pump Room Flood Protection 063 - Provide a water-tight door for additional protection of the RHR pumps against flooding.	$36,542	$45,071	$43,782	$36,542	$324,000
CCW Heat Exchanger Alternate Cooling Supply 064 - Provide backup cooling water source for the CCW heat exchangers.	$36,542	$45,071	$43,782	$36,542	$710,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Upgrade ASSS for RCP Seal Cooling 065 - Upgrade the ASSS to allow timely restoration of seal injection and cooling.	$1,722,733	$1,969,241	$2,319,905	$1,808,621	$560,000
Harden EDG Building 066 - Harden the EDG building and fuel oil transfer pumps against tornados and high winds.	$1,577,438	$1,978,824	$1,835,357	$1,601,977	>$10,000,000
Charging Pump Alternate Cooling 067 - Provide hardware connections to allow the primary water system to cool the charging pumps.	$8,091	$10,475	$8,879	$8,091	$576,000

Table E.2-3 (Continued)
Sensitivity Analysis Results

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 26 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Recirculation Pump Alternate Cooling 068 - Provide independent source of cooling for the recirculation pump motors.	$12,181	$15,024	$14,594	$12,181	$710,000

ATTACHMENT E.3

EVALUATION OF IP3 PSA MODEL

E.3 EVALUATION OF IP3 PROBABILISTIC SAFETY ANALYSIS MODEL

The severe accident risk was estimated using the Probabilistic Safety Analysis (PSA) model and a Level 3 model developed using the most recent version (version 1.13.1) of the MELCOR Accident Consequences Code System Version 2 (MACCS2) code. The CAFTA code was used to develop the Indian Point Unit 3 (IP3) PSA Level 1 and Level 2 models. This section provides the description of IP3 PSA Level 1, 2, and 3 analyses, core damage frequency (CDF) uncertainty, Individual Plant Examination of External Events (IPEEE) analyses, and PSA model peer review.

E.3.1 PSA Model - Level 1 Analysis

The PSA model (Level 1 and Level 2) used for the Severe Accident Mitigation Alternative (SAMA) analysis was the most recent internal events risk model for IP3 (Revision 2, April 2007) [Reference E.3-3]. This model is an updated version of the model used in the 1994 Individual Plant Examination (IPE) and reflects the IP3 configuration and design as of December 2005. It uses component failure and unavailability data as of December 2005 and resolves all findings and observations from the industry peer review of the model conducted in January 2001. The IP3 model adopts the small event tree / large fault tree approach and uses the CAFTA code for quantifying CDF.

The PSA model has been updated two times since the original IPE due to the following.

- Equipment performance: As data collection progresses, estimated failure rates and system unavailability data change.
- Plant configuration changes: Plant configuration changes are incorporated into the PSA model.
- Modeling changes: The PSA model is refined to incorporate the latest state of knowledge and recommendations from internal and industry peer reviews.

The PSA model contains the major initiators leading to core damage with baseline CDFs listed in Table E.3-1.

The IP3 Revision 2 PSA model was reviewed to identify those potential risk contributors that made a significant contribution to CDF. CDF-based Risk Reduction Worth (RRW) rankings were reviewed down to 1.005. Events below this point would influence the CDF by less than 0.5% and are judged to be highly unlikely contributors for the identification of cost-beneficial enhancements. These basic events, including component failures, operator actions, and initiating events, were reviewed to determine if additional SAMA actions may need to be considered.

Table E.3-2 provides a correlation between the Level 1 RRW risk significant events (component failures, operator actions, and initiating events) down to 1.005 identified from the IP3 Revision 2 PSA model and the SAMAs evaluated in Section E.4.

Table E.3-1
IP3 PSA Model CDF Results by Major Initiators

Accident Type	Point Estimate CDF (/ry)	% Contribution to Point Estimate CDF
Internal flooding	2.24E-06	19.66
Loss of coolant accident (LOCA)	2.16E-06	18.95
Steam generator tube rupture (SGTR)	1.57E-06	13.78
Anticipated transient without a scram (ATWS)	1.54E-06	13.51
Loss of 125 VDC power	1.00E-06	8.78
Transients[1]	8.48E-07	7.44
Station blackout (SBO)	7.20E-07	6.32
Total loss of service water system	5.41E-07	4.75
Loss of non-essential service water	2.76E-07	2.42
Interfacing system LOCA (ISLOCA)	1.53E-07	1.34
Loss of offsite power [1]	1.19E-07	1.04
Loss of component cooling water	1.11E-07	0.97
Vessel rupture	1.00E-07	0.88
Loss of essential service water [1]	1.78E-08	0.16
Total	**1.15E-05**	**100.00**

1. Contributions to CDF from SBO and ATWS are listed separately and thus not included in the contributions shown for other accident types.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
OLR-S2	6.10E-04	1.205	Failure to initiate low-head internal recirculation during small LOCA	This term represents failure to align low-head emergency core cooling system (ECCS) internal recirculation to deliver flow to reactor coolant system (RCS) cold legs during a small LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 034, to allow automatic swap-over to recirculation upon refueling water storage tank (RWST) low level, was evaluated.
AC4-XHE-FO-M312A	2.40E-01	1.196	Failure to align 6.9kV system to motor control center (MCC) 312A	This term represents failure to align alternate safe shutdown equipment to MCC 312A to establish RCS makeup following switchgear room flooding. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions has already been implemented. Phase II SAMA 61, to upgrade the alternate safe shutdown equipment to allow timely restoration of reactor coolant pump (RCP) seal injection and cooling, was evaluated.
IE-SL	2.50E-03	1.169	RCP seal LOCA initiator	This term represents the RCP seal LOCA initiating event. Phase I SAMAs improving ECCS sump strainer availability and emphasizing timely recirculation alignment in operator training have been implemented to mitigate this event. Phase II SAMAs 033, 034, 035, 037, 038 and 060, to enhance high and low pressure injection and recirculation systems and to provide an independent source of cooling for the recirculation pump motors, were evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
IE-T7	6.84E-03	1.158	SGTR initiator	This term represents a SGTR initiating event. Many Phase I SAMAs have been implemented to mitigate this event including improving detection and isolation capabilities, improving makeup capabilities to the RPV, improving primary side depressurization reliability, improving secondary side heat removal capability, and enhancing training. Phase II SAMAs 016, 017, 018, and 051, installing a highly reliable steam generator shell side heat removal system, increasing secondary side pressure capacity such that a SGTR would not cause the relief valve to lift, routing the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove the fission products, and enhancing procedure guidance to align main feedwater for secondary heat removal, were evaluated.
C	1.41E-05	1.152	Reactor protection system failure	This term represents failure of the reactor protection system. Improvements to minimize the risk associated with ATWS scenarios, including enhancement of operator training for ATWS and installation of an ATWS mitigating system actuation circuitry (AMSAC) system, have already been implemented. Phase II SAMAs 045, 046, 047 and 048, adding an independent boron injection system, adding relief valves to prevent equipment damage from pressure spikes, installing motor generator set trip breakers in the control room, and providing capability to remove power from the bus powering the control rods, were evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
IE-T2	2.89E-01	1.133	Loss of main feedwater initiator	This term represents an initiating event caused by loss of feedwater. Industry efforts over the last twenty years have led to a significant reduction of plant scrams from all causes. Phase II SAMAs 039 and 041, to install a digital feedwater upgrade and to add a motor-driven feedwater pump, were evaluated.
IE-3-IN-SW	4.35E-06	1.112	Rupture of 3 inch service water line in the control building switchgear room flood zone CTL15-1	This term represents an internal flooding event due to rupture of a 3 inch service water line in control building switchgear room flood zone CTL15-1. Phase I SAMAs have been implemented to improve procedures to reduce the CDF contribution due to internal flooding. Phase II SAMAs 055 and 062, providing the capability of powering one safety injection (SI) pump or residual heat removal (RHR) pump using the Appendix R bus (MCC 312A) during control building flooding events, and providing a flood alarm in the control building switchgear room, were evaluated.
PR1	2.58E-01	1.086	RCS overpressurization failure during ATWS	This term represents overpressurization of the RCS during ATWS. Improvements to minimize the risk associated with ATWS scenarios, including enhancement of operator training for ATWS and installation of an AMSAC system, have already been implemented. Phase II SAMAs 044, 047 and 048, to replace pressure-operated relief valves (PORVs) with larger ones to extend the time available for success of the feed and bleed function, to install motor generator set trip breakers in the control room, and to provide capability to remove power from the bus powering the control rods, were evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
IE-T1	5.86E-02	1.08	Loss of offsite power initiator	This term represents the loss of offsite power initiating event. Phase I SAMAs to enhance offsite power availability and coping with SBO events, including cross-tying diesel fuel oil supply lines, cross-tying alternating current (AC) and direct current (DC) buses, and adding additional diesel generators, have already been implemented. Phase II SAMAs 024, 025, 026, 027, 028, 029, 030, and 031, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
ORCS-L	1.00E-04	1.063	Failure to perform late RCS cooldown and depressurization during SGTR	This term represents failure to perform late cooling and depressurization to cold shutdown following a SGTR to terminate leakage from the RCS into the secondary prior to depleting RWST inventory. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 016, 017, 018, and 051, installing a highly reliable steam generator shell side heat removal system, increasing secondary side pressure capacity such that a SGTR would not cause the relief valve to lift, routing the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove the fission products, and enhancing procedure guidance to align main feedwater for secondary heat removal, were evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF) (Continued)

Event Name	Probability	RRW	Event Description	Disposition
EDG-ENG-FR-DG31R	3.84E-02	1.059	Diesel generator 31 fails to run	This term represents failure of emergency diesel generator (EDG) 31 to continue to run. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 024, 025, 026, 027, 028, 029, 030, and 031, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
IE-10-IN-FPS	2.22E-06	1.054	Rupture of 10 inch fire protection piping in the deluge room adjacent to control building switchgear room	This term represents an internal flooding event due to rupture of a 10 inch fire protection piping deluge valve station adjacent to the control building switchgear room. Phase I SAMAs have been implemented to improve procedures and to provide seismic support of the fire protection piping to reduce the CDF contribution due to internal flooding. Phase II SAMA 055, providing the capability of powering one SI pump or RHR pump using the Appendix R bus (MCC 312A) during control building flooding events, was evaluated.
IE-TSWS	5.20E-05	1.049	Total loss of service water system initiator	This term represents the loss of service water initiating event. Phase I SAMAs have been implemented to improve service water system reliability by providing additional service water pumps, enhancing screen wash, and replacing strainers. Phase II SAMAs 028, 029, and 057, to provide backup cooling water for the diesel generators and CCW heat exchangers, were evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
EDG-CCF-FR-3EDGS	8.09E-04	1.047	Common cause failure of 3 Diesel generators to continue to run	This term represents common cause failure of three diesel generators to continue to run. Phase II SAMAs 024, 025, 026, 027, 028, 029, 030, and 031, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
IE-TDC32	3.45E-04	1.047	Loss of 125VDC power panel 32 initiator	This term represents an initiating event caused by loss of 125VDC power panel 32. Phase I SAMAs implemented to enhance DC power availability and coping with SBO events include cross-tying DC buses and providing alternate battery charging capability. Phase II SAMAs 024, 025, 026, and 058, for enhancing DC system availability and reliability, were evaluated.
SL-TCCW	3.09E-02	1.047	Failure to align city water to charging pumps to prevent RCP seal LOCA	This term represents failure to align city water to the charging pumps for RCP seal cooling following loss of component cooling water (CCW). Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 059, to allow primary water to be used as a backup source of cooling, was evaluated.
IE-T5	1.00E-02	1.043	Main steam line break outside containment initiator	This term represents an initiating event caused by a main steam line break outside containment. Phase II SAMA 023, to improve main steam isolation valve (MSIV) design, was evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
IE-TDC3132	6.00E-06	1.043	Common cause failure of 125VDC power panels 31 and 32 initiator	This term represents an initiating event caused by loss of 125VDC power panels 31 and 32. Phase I SAMAs implemented to enhance DC power availability and coping with SBO events include cross-tying DC buses and providing alternate battery charging capability. Phase II SAMAs 024, 025, 026, and 058, for enhancing DC system availability and reliability, were evaluated.
B-DEP	5.45E-03	1.04	Failure to recover AC power given successful RCS depressurization	This term represents failure to recover offsite and onsite AC power following successful RCS depressurization. Phase I SAMAs to improve SBO procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 026, 042 and 056, improving DC bus load shedding, providing an additional power source to the turbine-drive auxiliary feedwater (AFW) pump auxiliaries, and installing pneumatic controls to assist in turbine-driven AFW pump control after battery depletion, were evaluated.
IE-T3	1.67E+00	1.036	Turbine trip with feedwater available initiator (T3)	This term represents an initiating event caused by a transient due to turbine trip with feedwater available. Industry efforts over the last twenty years have led to a significant reduction of plant scrams from all causes. A Phase I SAMA to replace the solenoids and air operators of the MSIVs to enhance reliability of the MSIVs has been implemented. Phase II SAMA 023, to improve the MSIV design to reduce the frequency of the initiator, was evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
AFW-MAI-MA-TDP32	6.92E-03	1.03	AFW turbine-driven pump 32 out for testing and maintenance	This term represents AFW turbine-driven pump 32 out for testing and maintenance. Phase II SAMAs 041 and 043, adding an additional motor-driven pump to enhance AFW system reliability and using fire water as a backup supply to the steam generators, were evaluated.
IE-S2	5.00E-04	1.03	Small break LOCA initiator	This term represents the small LOCA initiating event. Phase I SAMAs improving ECCS sump strainer availability and emphasizing timely recirculation alignment in operator training have been implemented to mitigate this event. Phase II SAMAs 033, 034, 035, 037, 038 and 060, to enhance high and low pressure injection and recirculation systems and provide an independent source of cooling for the recirculation pump motors, were evaluated.
WRWST	8.40E-02	1.027	Failure to refill RWST for continuing core cooling during SGTR	This term represents failure to align water from the primary water storage tank to refill the RWST for continuing core cooling during a SGTR event. A Phase I SAMA was implemented providing hardware and a procedure to extend RWST capacity. Phase II SAMAs 016, 017, 018, and 051, installing a highly reliable steam generator shell side heat removal system, increasing secondary side pressure capacity such that a SGTR would not cause the relief valve to lift, routing the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove the fission products, and enhancing procedure guidance to align main feedwater for secondary heat removal, were evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
FB-T7	1.00E+00	1.026	Failure to initiate feed and bleed during SGTR	This term represents failure to establish core cooling using feed and bleed following loss of main feedwater and AFW during a SGTR event. Phase I SAMAs to improve operator response, install computer aided instrumentation and keep pressurizer PORV block valves open have already been implemented. Phase II SAMA 044, to replace current PORVs with larger ones to extend the time available for success of the bleed and feed function, was evaluated.
IE-TSWS-NE	1.67E-03	1.025	Loss of non-essential service water system initiator	This term represents the loss of non-essential service water initiating event. Phase I SAMAs have been implemented to improve service water system reliability by providing additional service water pumps, cross-tying service water pumps, enhancing screen wash, and replacing strainers. Phase II SAMA 057, to provide backup cooling water for the CCW heat exchangers, was evaluated.
MRI	1.70E-01	1.025	Failure of manual rod insertion during ATWS	This term represents failure to insert control rods during an ATWS event. Improvements to minimize the risk associated with ATWS scenarios, including enhancement of operator training for ATWS and installation of an AMSAC system, have already been implemented. Phase II SAMAs 045, 046, 047 and 048, adding an independent boron injection system, adding relief valves to prevent equipment damage from pressure spikes, installing motor generator set trip breakers in the control room, and providing capability to remove power from the bus powering the control rods, were evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
PR2	3.74E-01	1.024	ATWS RCS overpressurization failure (manual rod insertion failure)	This term represents overpressurization of the RCS during ATWS (manual rod insertion failure). Improvements to minimize the risk associated with ATWS scenarios, including enhancement of operator training for ATWS and installation of an AMSAC system, have already been implemented. Phase II SAMAs 044, 047 and 048, to replace PORVs with larger ones to extend the time available for success of the feed and bleed function, to install motor generator set trip breakers in the control room, and to provide capability to remove power from the bus powering the control rods, were evaluated.
SGISO	6.70E-03	1.024	Failure to isolate ruptured steam generator during SGTR	This term represents failure to isolate the ruptured steam generator during a SGTR event. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 016, 017, 018, and 051, installing a highly reliable steam generator shell side heat removal system, increasing secondary side pressure capacity such that a SGTR would not cause the relief valve to lift, routing the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove the fission products, and enhancing procedure guidance to align main feedwater for secondary heat removal, were evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
AFW-XHE-RE-AFW32	5.00E-03	1.023	Failure to restore AFW turbine-driven pump 32 path components after maintenance	This term represents failure to restore AFW turbine-driven pump 32 after testing and maintenance. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 041 and 043, adding a motor-driven feedwater pump and installing a fire water backup supply to the steam generators, were evaluated.
IE-TT15	3.40E-07	1.022	Rupture of fire protection piping in the turbine building outside the control building switchgear room	This term represents an internal flooding event due to rupture of fire protection piping in the turbine building outside the control building switchgear room This event causes damage to the 480V switchgear. Phase I SAMAs have been implemented to improve procedures to reduce the CDF contribution due to internal flooding. Phase II SAMA 062, providing a flood alarm in the control building switchgear room, was evaluated.
SL-DEP	2.57E-03	1.018	RCP seal LOCA induced core uncovery	This term represents failure to recover offsite AC power before RCP seal LOCA causes core uncovery. Phase I SAMAs to improve SBO procedures and training to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 033, 034, 035, 037, 038 and 060, to enhance high and low pressure injection and recirculation systems and to provide an independent source of cooling for the recirculation pump motors, were evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
RCS-XHE-MC-PT402	8.00E-03	1.017	RCS pressure transmitter PT-402 miscalibration	This term represents failure to properly calibrate RCS pressure transmitter PT-402, leading to failure of a motor-operated valve (MOV) in the RCS shutdown cooling line to open on demand. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. No Phase II SAMAs were recommended for this subject.
RCS-XHE-MC-PT403	8.00E-03	1.017	RCS pressure transmitter PT-403 miscalibration	This term represents failure to properly calibrate RCS pressure transmitter PT-403, leading to failure of an MOV in the RCS shutdown cooling line to open on demand. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. No Phase II SAMAs were recommended for this subject.
IE-4-IN-FPS	6.19E-07	1.015	Rupture of 4 inch fire protection piping in the control building switchgear room flood zone CTL15-3	This term represents an internal flooding event due to rupture of a 4 inch fire protection pipe in control building switchgear room flood zone CTL15-3. Phase I SAMAs have been implemented to improve procedures and to provide seismic support for the fire protection piping to reduce the CDF contribution due to internal flooding. Phase II SAMAs 055 and 062, providing the capability of powering one SI pump or RHR pump using the Appendix R bus (MCC 312A) during control building flooding events, and providing a flood alarm in the control building switchgear room, were evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
AFW-TDP-FS-TDP32	3.07E-03	1.014	AFW turbine-driven pump 32 fails to start on demand	This term represents failure of AFW turbine driven pump 32 to start on demand. Phase II SAMAs 041 and 043, adding an additional motor-driven pump to enhance AFW system reliability and using fire water as a backup supply to the steam generators, were evaluated.
EDG-MAI-MA-EDG31	9.60E-03	1.013	Diesel generator 31 out for maintenance	This term represents EDG 31 out for maintenance. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 024, 025, 026, 027, 028, 029, 030, and 031, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
AFW-CCF-CC-3149	1.14E-05	1.011	Common cause failure of check valves BFD-31, 34 & 39	This term represents common cause failure of check valves BFD-31, 34 and 39, leading to failure of all AFW pumps to deliver sufficient flow to the steam generators. Phase II SAMAs 041, 043, 044, and 054, adding an additional motor-driven pump to enhance AFW system reliability, using fire water as a backup supply to the steam generators, replacing PORVs with larger ones and providing DC power backup for the PORVs, were evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
AFW-XHE-RE-AFW31	4.70E-03	1.011	Failure to restore AFW motor-driven pump 31 path components after testing and maintenance	This term represents failure to restore AFW motor-driven pump 31 after testing and maintenance. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 041, 042, 043, and 054, adding an additional motor-driven pump, providing a portable generator to support the turbine-driven pump auxiliaries, using fire water as a backup supply to the steam generators, and installing pneumatic control and indication for AFW turbine driven pump 32, were evaluated.
ORCS-MSLB	8.10E-03	1.011	Failure to depressurize RCS during main steam line break	This term represents failure to depressurize the RCS during a main steam line break. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 038 and 044, to enhance the reactor coolant depressurization system and replace PORVs with larger ones, were evaluated.
AFW-CCF-FS-AFWPM	3.12E-04	1.01	Common cause failure of AFW motor-driven pumps 31 and 33 to start	This term represents common cause failure of AFW motor-driven pumps 31and 33 to start. Phase II SAMAs 041, 043, and 056, adding an additional motor-driven pump, using fire water as a backup supply to the steam generators, and installing pneumatic control and indication for AFW turbine-driven pump 32, were evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
EDG-ENG-FR-DG32R	3.84E-02	1.01	Diesel generator 32 fails to run	This term represents random failure of EDG 32 to continue to run. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 024, 025, 026, 027, 028, 029, 030, and 031, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
FB-T3	1.70E-02	1.01	Failure to initiate feed and bleed cooling during turbine trip (T3)	This term represents failure to establish core cooling using feed and bleed following a turbine trip and loss of main feedwater and AFW. Phase I SAMAs to improve operator response, install computer aided instrumentation and keep pressurizer PORV block valves open to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 043, 044 and 054, to use fire water as a backup supply to the steam generators, to improve the availability of the feed and bleed function by replacing the current PORVs with larger capacity valves and to provide DC power backup for the PORVs, were evaluated.
IE-TCCW	3.28E-04	1.01	Loss of CCW initiator	This term represents the loss of CCW system initiating event. Many Phase I SAMAs have been implemented to provide more reliable or diverse high or low pressure injection, RCP seal cooling systems and enhancements to loss of CCW procedures to mitigate this event. Phase II SAMAs 003, 004 and 057, to provide an additional CCW pump, improve the ability to cool the RHR heat exchangers and provide a backup cooling water source for the CCW heat exchangers, were evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
IE-V1	3.51E-05	1.01	Interfacing LOCA (<6") with isolation	This term represents the ISLOCA initiating event. Phase I SAMAs to improve procedures to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 019 and 021, to install additional pressure or leak monitoring instrumentation for ISLOCAs and increase leak testing of valves in ISLOCA pathways, were evaluated.
ODEPR-S2	2.00E-03	1.01	Failure to depressurize RCS for post-LOCA cooldown during small break LOCA	This term represents failure to depressurize the RCS following a small break LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 038 and 044, to enhance the reactor coolant depressurization system and replace PORVs with larger ones, were evaluated.
OHR-S2	7.10E-04	1.01	Failure to initiate high-head internal recirculation during small LOCA	This term represents failure to align high-head ECCS internal recirculation to deliver flow to the RCS cold legs during a small LOCA. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 034, to allow automatic swap-over to recirculation upon RWST low level, was evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF) (Continued)

Event Name	Probability	RRW	Event Description	Disposition
AFW-XHE-RE-AFWCC	9.60E-06	1.009	Failure to restore all AFW pumps after testing and maintenance	This term represents failure to restore all AFW pumps after testing and maintenance, leading to failure of all AFW pumps to deliver sufficient flow to the steam generators. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. In addition, Phase II SAMAs 043, 044 and 054, to use fire water as a backup supply to the steam generators, to improve the availability of the feed and bleed function by replacing the current PORVs with larger capacity valves and to provide DC power backup for the PORVs, were evaluated.
IE-R	1.00E-07	1.009	Catastrophic reactor vessel rupture	This term represents an initiating event caused by reactor vessel rupture. Phase II SAMAs 010 and 014, using fire protection system as a backup source for the containment spray system and providing redundant containment spray systems to mitigate the consequence of a reactor vessel rupture, were evaluated.
OHR-TCCW	1.01E-03	1.009	Failure to initiate low-head internal recirculation given loss of CCW system	This term represents failure to align low-head ECCS internal recirculation to deliver flow to the RCS cold legs following loss of CCW. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 034, to allow automatic swap-over to recirculation upon RWST low level, was evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
RHR-SD	9.60E-04	1.009	Failure to align RHR for shutdown cooling mode	This term represents failure to align RHR shutdown cooling mode during a SGTR event. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 016, 017, 018, and 051, installing a highly reliable steam generator shell side heat removal system, increasing secondary side pressure capacity such that a SGTR would not cause the relief valve to lift, routing the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove the fission products, and enhancing procedure guidance to align main feedwater for secondary heat removal, were evaluated.
EDG-ENG-FR-DG33R	3.84E-02	1.008	Diesel generator 33 fails to run	This term represents failure of EDG 33 to continue to run. Phase I SAMAs to improve availability of the EDGs by cross-tying diesel fuel oil supply lines and proceduralizing fuel oil replenishment have already been implemented. Phase II SAMAs 024, 025, 026, 027, 028, 029, 030, and 031, for enhancing AC or DC system reliability or to cope with loss of offsite power and SBO events, were evaluated.
IE-S1	4.00E-05	1.008	Intermediate break LOCA initiator	This term represents the intermediate LOCA initiating event. Phase I SAMAs improving ECCS sump strainer availability and emphasizing timely recirculation alignment in operator training have been implemented to mitigate this event. Phase II SAMAs 033, 034, 035, 036, 037, 038, and 060, to enhance high and low pressure injection and recirculation systems and provide an independent source of cooling for the recirculation pump motors, were evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
VISO-S2	2.50E-02	1.008	Failure to isolate ISLOCA resulting in intermediate LOCA	This term represents failure to isolate an intermediate size ISLOCA. Phase I SAMAs to improve procedures to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMA 20, adding redundant and diverse limit switches to each containment isolation valve to reduce the frequency of unrecognized containment isolation failure and ISLOCAs through enhanced isolation valve position indication, was evaluated.
VL-OUTSIDE	1.00E-01	1.008	ISLOCA outside containment	This term represents the ISLOCA outside containment initiating event. Phase II SAMAs 019 and 021, to install additional pressure or leak monitoring instrumentation for ISLOCAs and increase leak testing of valves in ISLOCA pathways, were evaluated.
AFW-AOV-CC-P1139	1.68E-03	1.007	AFW turbine-driven pump 32 steam control valve PCV-1139 does not open	This term represents failure of steam control valve PCV-1139, leading to unavailability of AFW turbine-driven pump 32. Phase II SAMAs 041 and 043, adding an additional motor-driven pump to enhance AFW system reliability and using fire water as a backup supply to the steam generators, were evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
AFW-XHE-FO-HC405	9.00E-04	1.007	Failure to operate AFW turbine-driven pump 32 flow control valves HC-405A,B,C & D	This term represents failure of control valves 405A/B/C/D, leading to unavailability of AFW turbine-driven pump 32. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 041, 043, and 056, adding an additional motor-driven pump to enhance AFW system reliability, using fire water as a backup supply to the steam generators, and installing pneumatic control and indication for AFW turbine-driven pump 32, were evaluated.
IE-3-IN-SW-AC1	2.88E-06	1.007	Rupture of 3 inch service water line in the control building switchgear room flood zone CTL15-2	This term represents an internal flooding event due to rupture of a 3 inch service water line in control building switchgear room flood zone CTL15-2. Phase I SAMAs have been implemented to improve procedures to reduce the CDF contribution due to internal flooding. Phase II SAMAs 055 and 062, providing the capability of powering one SI pump or RHR pump using the Appendix R bus (MCC 312A) during control building flooding events, and providing a flood alarm in the control building switchgear room, were evaluated.
AFW-MDP-FR-PM31	2.81E-03	1.006	AFW motor-driven pump 31 fails to continue to run	This term represents failure of AFW motor-driven pump 31 to continue to run. Phase II SAMAs 041, 043, and 056, adding an additional motor-driven pump to enhance AFW system reliability, using fire water as a backup supply to the steam generators, and installing pneumatic control and indication for AFW turbine-driven pump 32, were evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
AFW-RCK-NO-PM31	2.50E-03	1.006	AFW motor-driven pump 31 switchgear control circuit no output	This term represents failure of AFW motor-driven pump 31 control circuit, causing unavailability of the pump. Phase II SAMAs 041, 043, and 056, adding an additional motor-driven pump to enhance AFW system reliability, using fire water as a backup supply to the steam generators, and installing pneumatic control and indication for AFW turbine-driven pump 32, were evaluated.
CVC-RCK-NO-CH333	2.50E-03	1.006	Emergency boration valve CH-MOV-333 control circuit no output	This term represents failure of MOV-333, resulting in failure of emergency boration during an ATWS. Improvements to minimize the risk associated with ATWS scenarios, including enhancement of operator training for ATWS and installation of an AMSAC system, have already been implemented. Phase II SAMAs 045, 047 and 048, to add an independent boron injection system, install motor generator set trip breakers in the control room, and provide capability to remove power from the bus powering the control rods, were evaluated.
FB-T2	1.70E-02	1.006	Failure to initiate feed and bleed cooling during transient	This term represents failure to establish core cooling using feed and bleed following a transient and loss of main feedwater and AFW. Phase I SAMAs to improve operator response, install computer aided instrumentation and keep pressurizer PORV block valves open to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 043, 044 and 054, to use fire water as a backup supply to the steam generators, to improve availability of the feed and bleed function by replacing the PORVs with larger capacity valves, and to provide DC power backup for the PORVs, were evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
IE-TA18	2.73E-05	1.006	Rupture of condensate line in AFW pump room flood zone AFW18-1	This term represents an internal flooding event due to rupture of a condensate line in AFW pump room flood zone AFW18-1. This event causes loss of the AFW system and potential loss of the MFW system. Phase II SAMAs 043, 044, and 054, to use fire water as a backup supply to the steam generators, to improve the availability of the feed and bleed function by replacing the PORVs with larger capacity valves, and to provide DC power backup for the PORVs, were evaluated.
IE-TAC6A	1.05E-03	1.006	Loss of 480V bus 6A initiator	This term represents an initiating event caused by loss of 480V bus 6A. A Phase I SAMA to proceduralize repair or replacement of failed 480V breakers has already been implemented. Phase II SAMAs 024, 025, 026, 027, and 030, for enhancing AC or DC system reliability, were evaluated.
LTS	2.50E-03	1.006	Failure to establish long-term shutdown during ATWS	This term represents failure to establish long term shutdown via emergency boration during an ATWS. Improvements to minimize the risk associated with ATWS scenarios, including enhancement of operator training for ATWS and installation of an AMSAC system, have already been implemented. Phase II SAMAs 045, 047 and 048, to add an independent boron injection system, install motor generator set trip breakers in the control room, and provide capability to remove power from the bus powering the control rods, were evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
AFW-MAI-MA-PM31	3.06E-03	1.005	AFW motor-driven pump 31 out for testing and maintenance	This term represents AFW motor-driven pump 31 out for testing and maintenance. Phase II SAMAs 041, 043, and 056, adding an additional motor-driven pump to enhance AFW system reliability, using fire water as a backup supply to the steam generators, and installing pneumatic control and indication for AFW turbine-driven pump 32, were evaluated.
FB-TAC6A	1.70E-01	1.005	Failure to initiate feed and bleed cooling during loss of 480V bus 6A	This term represents failure to establish core cooling using feed and bleed following loss of 480V bus 6A and loss of main feedwater and AFW. Phase I SAMAs to improve operator response, install computer aided instrumentation and keep pressurizer PORV block valves open to enhance the likelihood of success of operator action have already been implemented. Phase II SAMAs 043, 044 and 054, to use fire water as a backup supply to the steam generators, to improve the availability of the feed and bleed function by replacing the PORVs with larger capacity valves, and to provide DC power backup for the PORVs, were evaluated.
IE-T4	4.63E-04	1.005	Main steam line break inside containment initiator	This term represents the main steam line break inside the containment initiating event. Phase II SAMAs 011, 014, 023, and 050, providing a passive and redundant containment spray system, improving MSIV design, and installing guard pipes up to the MSIVs, were evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
LHI-RCK-NO-744	2.50E-03	1.005	AC-MOV-744 control circuit no output	This term represents failure of MOV 744 control circuit, leading to loss of external recirculation capability during LOCAs and transients. Phase II SAMA 060, providing an independent source of cooling for the recirculation pump motors, was evaluated.
LHI-RCK-NO-885A	2.50E-03	1.005	SI-MOV-885A control circuit no output	This term represents failure of MOV 885A control circuit, leading to loss of external recirculation capability during LOCAs and transients. Phase II SAMA 060, providing an independent source of cooling for the recirculation pump motors, was evaluated.
LHI-RCK-NO-885B	2.50E-03	1.005	SI-MOV-885B control circuit no output	This term represents failure of MOV 885B control circuit, leading to loss of external recirculation capability during LOCAs and transients. Phase II SAMA 060, providing an independent source of cooling for the recirculation pump motors, was evaluated.
MSGI-T4	3.30E-02	1.005	Failure to isolate faulted steam generator	This term represents failure to isolate the affected steam generator during a main steam line break event. Phase II SAMAs 011, 014, 023, and 050, providing a passive and redundant containment spray system, improving MSIV design, and installing guard pipes up to the MSIVs, were evaluated.
OCOND	5.30E-03	1.005	Failure to align condensate system for secondary cooling	This term represents failure to align the condensate system for secondary cooling during transients. Phase I SAMAs to improve operator response and install computer aided instrumentation to enhance the likelihood of success of operator action have already been implemented. Phase II SAMA 043, using the fire water system as backup for steam generator inventory, was evaluated.

Table E.3-2
IP3 Correlation of Level 1 Risk Significant Terms to Evaluated SAMAs (Based on CDF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
ODEP-TCCW	4.00E-03	1.005	Failure to depressurize during loss of CCW	This term represents failure to depressurize the RCS following loss of the CCW system. Phase I SAMAs to improve procedures and install instrumentation to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 038 and 044, to enhance the reactor coolant depressurization system and replace PORVs with larger ones, were evaluated.
RV-T4	6.70E-03	1.005	Reactor vessel rupture during main steam line break inside containment	This term represents failure to terminate SI following a main steam line break inside containment, causing reactor vessel rupture due to pressurized thermal shock. Phase II SAMAs 011, 014, 023, and 050, providing a passive and redundant containment spray system, improving MSIV design, and installing guard pipes up to the MSIVs, were evaluated.

CDF Uncertainty

The uncertainty associated with CDF was estimated using Monte Carlo techniques implemented in CAFTA for the base case mode. The results are shown in Table E.3-3.

Table E.3-3
CDF Uncertainty

Confidence	CDF (/ry)
Mean value	1.23E-5
5^{th} percentile	8.45E-6
50^{th} percentile	1.11E-5
95^{th} percentile	1.72E-5

The values in Table E.3-3 reflect the uncertainties associated with the data distributions used in the analysis. The ratio of the 95th percentile to the mean CDF is about 1.40. This uncertainty factor is included in the factor of 8 used to determine the "baseline benefit with uncertainty" described in Section 4.21.5.4.

E.3.2 PSA Model - Level 2 Analysis

E.3.2.1 Containment Performance Analysis

The IP3 Level 2 PSA model used for the SAMA analysis is the most recent internal events risk model, which is an updated version of the model used in the IPE [Reference E.3-1]. The Level 2 PSA model used for the SAMA analysis, Revision 2 [Reference E.3-3] reflects the IP3 operating configuration and design changes as of December 2005.

The IP3 Level 2 model includes two types of considerations: (1) a deterministic analysis of the physical processes for a spectrum of severe accident progressions, and (2) a probabilistic analysis component in which the likelihood of the various outcomes are assessed. The deterministic analysis examines the response of the containment to the physical processes during a severe accident. This response is performed by

- utilization of the Modular Accident Analysis Program (MAAP) code [Reference E.3-4] to simulate severe accidents that have been identified as dominant contributors to core damage in the Level 1 analysis, and
- reference MAAP calculations of several hydrodynamic and heat transfer phenomena that occur during the progression of severe accidents. Examples include debris coolability, pressure spikes due to ex-vessel steam explosions, direct containment heating (DCH), molten debris filling the reactor pit, containment bypass, deflagration and detonation of hydrogen, thrust forces at reactor vessel failure, and thermal attack of containment penetrations.

The Level 2 analysis examined the dominant accident sequences and the resulting plant damage states (PDS) defined in Level 1. The Level 1 analysis involves the assessment of those scenarios that could lead to core damage.

A full Level 2 model was developed for the IP3 PSA and completed at the same time as the Level 1 model. The Level 2 model consists of a single containment event tree (CET) with functional nodes that represent phenomenological events and containment protection system status. The nodes were quantified using subordinate trees and logic rules. A list of the CET functional nodes and descriptions used for the Level 2 analysis is presented in Table E.3-4.

The Large Early Release Frequency (LERF) is an indicator of containment performance from the Level 2 results because the magnitude and timing of these releases provide the greatest potential for early health effects to the public. The frequency calculated is approximately 9.43E-7/ry [Reference E.3-3]. Figures E.3-1 and E.3-2 summarize the Level 2 results. Radionuclide release categories are described in Section E.3.2.2.3.

LERF represents a small fraction (8%) of all release end states. Three types of accidents dominate the internal large early release: accidents initiated by SGTRs, ISLOCAs, and accidents initiated by internal floods impacting vital power buses. (Internal floods impacting vital power buses contribute to LERF because they result in SBO and core damage without power available to the 480 VAC safeguard buses for the duration of the event. A large release occurs due to early containment rupture at vessel breach from either containment overpressurization or hydrogen burns.)

Table E.3-5 provides a correlation between the Level 2 RRW risk significant events (severe accident phenomenon, initiating events, component failures and operator actions) down to 1.005 identified from the current IP3 Revision 2 PSA LERF model [Reference E.3-3] and the SAMAs evaluated in Section E.4.

Table E.3-4
Notation and Definitions for IP3 CET Functional Nodes

CET Node	CET Functional Node Description
Plant Damage State Event (PDS_EVNT)	This top event represents the initiators considered in the containment performance analysis.
RCS Pressure at Vessel Failure (RCS@VF)	This top event identifies the status of the RCS pressure. RCS@VF is set to success when RCS pressure is low. RCS@VF is set to failure when RCS pressure is high.
In-vessel Cooling Recovery (IN-REC)	This top event addresses the recovery of coolant injection into the vessel after core degradation, but prior to vessel breach. This top event considers the possibility of low-pressure injection systems working once the RCS is depressurized.
Vessel Failure (VF)	This top event addresses recovery from core degradation within the vessel and the prevention of vessel head thermal attack. Core melt recovery requires the recovery of core cooling prior to core blocking or relocation of molten debris to the lower plenum and thermal attack of the vessel head.
Early Containment Failure (CFE)	This top event node considers the potential loss of containment integrity at, or before, vessel failure. Several phenomena are considered credible mechanisms for early containment failure. They may occur alone or in combination. The phenomena are containment isolation failure; containment bypass; containment overpressure failure at vessel breach; hydrogen deflagration or detonation; fuel-coolant interactions (steam explosions); and high pressure melt ejection (HPME) with subsequent DCH.

**Table E.3-4
Notation and Definitions for IP3 CET Functional Nodes
(Continued)**

CET Node	CET Functional Node Description
Debris Cooled Ex-vessel (DCOOL)	This top event considers the delivery of water to the reactor pit (sump), via containment sprays, or via injection to the vessel and drainage out a vessel breach into the reactor pit area. Success implies the availability of water and the formation of a coolable debris bed such that concrete attack is precluded. Failure implies that the molten core attacks concrete in the reactor pit, that core debris remains hot, and sparing of the concrete decomposition products through the melt releases the less volatile fission products to the containment atmosphere.
Late Containment Failure (CFL)	This top event addresses the potential loss of containment integrity in the long-term. Late containment failure may result from base mat melt-through or from long-term steam and non-condensable gas generation from the attack of molten core debris on concrete.
Fission Product Removal (FPR)	This top event addresses fission product releases from the fuel into the containment and airborne fission product removal mechanisms within the containment structure to characterize potential magnitude of fission product releases to the environment should the containment fail. Failure implies that most of the fission products from the fuel and containment are ultimately released to the environment without mitigation.
Containment Failure Mode (CFM)	This top event is used to characterize the impact of the timing of containment failure and the break size on the duration and mitigation of the fission product source terms.

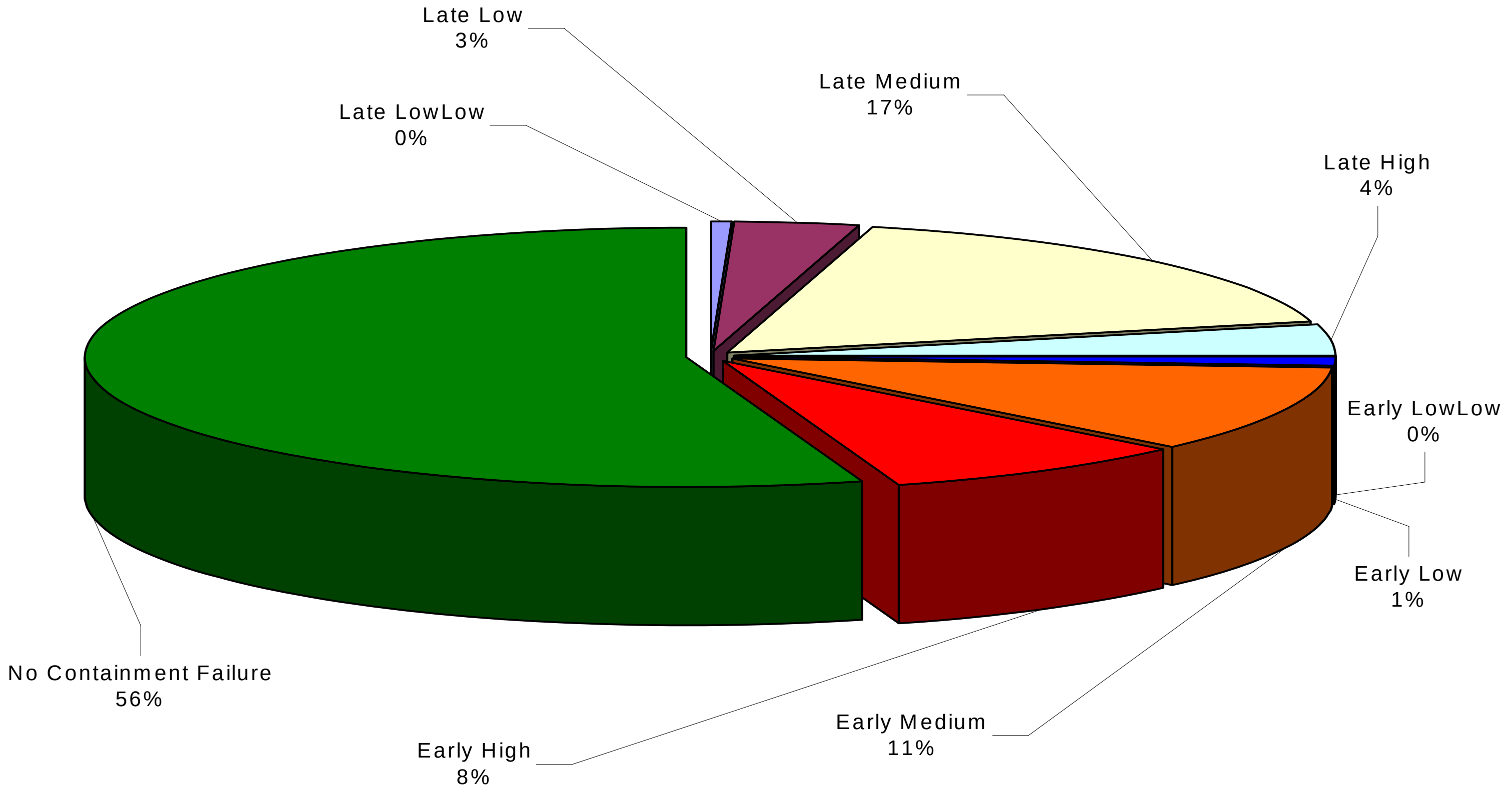

Figure E.3-1
IP2 Radionuclide Release Category Summary

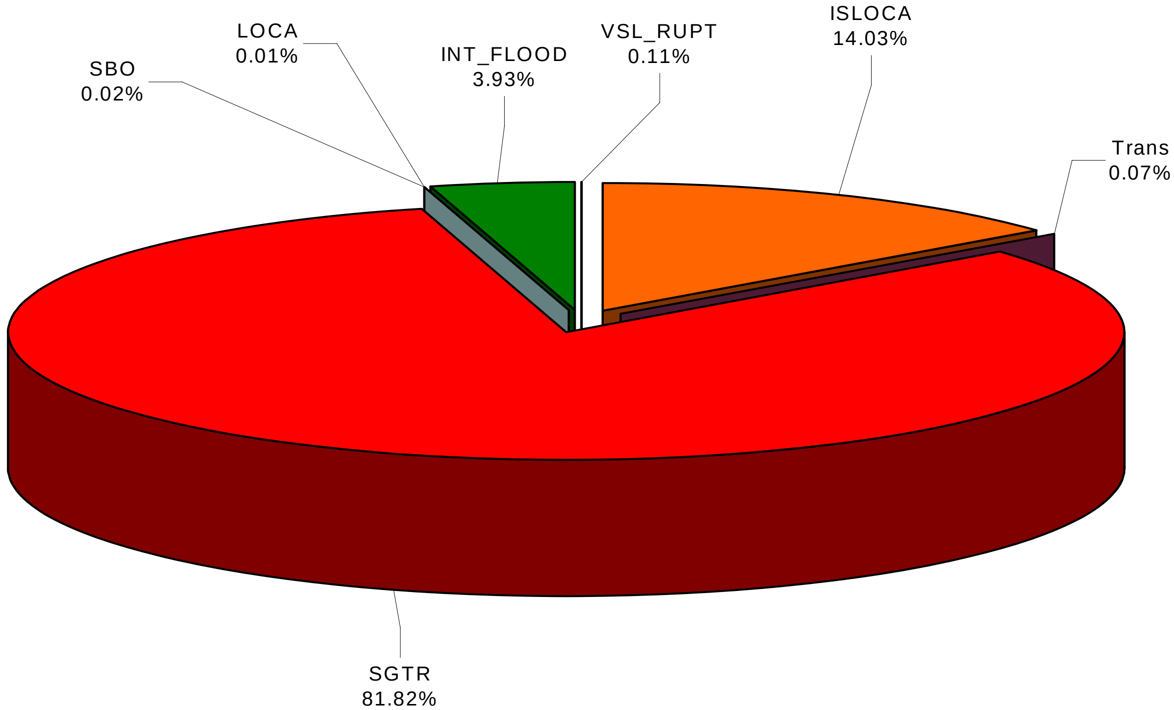

Figure E.3-2
IP2 Contributions to Large Early Release Frequency

Table E.3-5
IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
NO-FPR_BYPASS	1.0	24.124	No fission product removal due to containment bypass event	This term represents the probability that fission product removal does not occur because containment is bypassed by either an ISLOCA or a SGTR with a stuck-open relief valve. Phase II SAMAs 019, 020, 021 and 022, to install additional pressure or leak monitoring instrumentation, increase leak testing of ISLOCA valves, add redundant and diverse limit switches to containment isolation valves, and ensure ISLOCA releases are scrubbed, were evaluated. For SGTR sequences, numerous Phase I SAMAs have been implemented to increase reliability of the steam generator via enhanced maintenance practices, improved detection and isolation capabilities, improved makeup capabilities to the RCS, improved primary side depressurization reliability, improved secondary side heat removal capability, by installation of new steam generators in 1989, and enhanced SGTR training. Phase II SAMAs 016, 017 and 018 were evaluated to mitigate SGTR events.
NO_SAG-2	1.0	5.873	RCS depressurization failure-post core melt	This term represents the probability that RCS depressurization as described in severe accident guideline SAG-2, "Depressurize the RCS," is not performed during a high pressure core melt accident. Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated. In addition, Phase II SAMA 026, to improve DC bus load shedding to extend DC power availability, was evaluated.

Table E.3-5
IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
NO_HLSL_1	0.90	5.731	RCS hot leg or pressurizer surge line remains intact during medium pressure accident scenario	This term represents the probability that either the RCS hot leg or pressurizer surge line remains intact during an accident in which the RCS system pressure is between 675 psig and 2235 psig. A Phase I SAMA to keep pressurizer PORV block valves open to increase PORV availability has already been implemented. Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.
PDS_FRAC-51	6.73E-02	5.496	Long-term SGTR with stuck-open safety relief valve	This term is the PDS split fraction for a long-term SGTR scenario involving failure to isolate the ruptured steam generator and subsequent stuck-open steam generator safety relief valve. Phase I SAMAs were implemented providing procedures to enhance the likelihood of success of operator action in response to SGTR accident conditions and increasing the reliability of the steam generator via enhance maintenance practices. Phase II SAMAs 016, 017 and 018 were evaluated to mitigate SGTR events.
PDS_FRAC-49	7.66E-03	1.103	Long-term small ISLOCA outside containment event	This term is the PDS split fraction for a long-term small break ISLOCA outside containment. Phase II SAMAs 019, 020, 021, and 022, to install additional pressure or leak monitoring instrumentation, increase leak testing of ISLOCA valves, add redundant and diverse limit switches to containment isolation valves, and ensure ISLOCA releases are scrubbed, were evaluated.

Table E.3-5
IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
DP-46	0.1	1.089	RCS pressure is low at vessel breach given a long-term SGTR with stuck-open safety relief valve	This term represents the probability that RCS depressurization occurs during a long-term SGTR with stuck-open safety relief valve. Phase II SAMAs 016 and 017 to provide shell side heat removal and increase secondary pressure capacity to improve secondary heat removal, were evaluated. In addition, Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.
PDS_FRAC-50	3.87E-03	1.050	Short -term large ISLOCA outside containment event	This term is the PDS split fraction for a short-term large break ISLOCA outside containment. Phase II SAMAs 019, 020, 021, and 022, to install additional pressure or leak monitoring instrumentation, increase leak testing of ISLOCA valves, add redundant and diverse limit switches to containment isolation valves, and ensure ISLOCA releases are scrubbed, were evaluated.
DP-45	1.0	1.050	RCS pressure is low at vessel breach given a large ISLOCA event	This term represents the probability that RCS depressurization occurs during a short-term large break ISLOCA outside containment. Phase I SAMAs to improve procedures to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 019, 020, 021, and 022, to install additional pressure or leak monitoring instrumentation, increase leak testing of ISLOCA valves, add redundant and diverse limit switches to containment isolation valves, and ensure ISLOCA releases are scrubbed, were evaluated.

Table E.3-5
IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
NO_SAG-4	1.00	1.042	Containment injection post core melt does not occur	This term represents the probability that injection into containment as described in severe accident guideline SAG-4, "Inject Into Containment," is not performed to cool the lower head of the reactor vessel. An additional benefit of flooding the containment is that water will be available for ECCS recirculation and to flood core debris in the reactor pit area after vessel breach. Phase II SAMAs 006 and 007, to contain molten core debris in the reactor pit area and to create a reactor cavity flooding system, were evaluated.
SLUMP_3	0.10	1.036	Core slump probability given CM>20% and no injection	This term represents the probability of core slump to the lower head as a large mass, given no in-vessel injection. Phase II SAMAs 032, 033, 034, 035, 036, and 037, for enhancing reactor vessel injection and recirculation cooling, were evaluated.
VF_SIZE_PEN	0.90	1.035	Vessel penetration failure occurs debris thermal attack	This term represents the probability of vessel failure due to a single lower head penetration failure. Phase II SAMA 007 was evaluated to consider the benefit of a reactor vessel exterior cooling system with the potential to cool a molten core before it causes vessel failure.
NO-INVESSEL-COOL	1.0	1.035	In-vessel cooling failure post core damage	This flag event indicates that in-vessel cooling fails during a core melt progression. Phase II SAMAs 032, 033, 034, 035, 036, and 037, for enhancing reactor vessel injection during transients, small LOCA and SBO, were evaluated.

Table E.3-5
IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
DCH_OCCURS	0.50	1.035	DCH occurs given HPME phenomena	This term represents the probability that DCH occurs following HPME. Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated. In addition, Phase II SAMA 015, to erect a barrier to provide enhanced protection of the containment shell from ejected core debris following a core melt scenario at high pressure, and SAMA 026, to improve DC bus load shedding to extend DC power availability, were evaluated.
AC_SBO_FLOOD	1.032	1.135	Internal flooding induced SBO event fails ac power supply	This flag event indicates that AC power to the normal offsite supply buses and vital AC safeguard buses is disabled following an internal flooding event that impacts the control building switchgear room at the 15-foot elevation. Phase II SAMAs 055, 061, and 062, to upgrade the ASSS to allow timely restoration of seal injection and cooling, to install a flood alarm in the 480VAC switchgear room, and to provide the capability of powering one SI pump or RHR pump using the Appendix R bus (MCC 312A) during control building flooding events, were evaluated.

Table E.3-5
IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
PDS_FRAC-45	8.35E-02	1.030	Long-term internal flood induced SBO sequence	This term is the PDS split fraction for a long-term internal flood event that entails failure of normal offsite supply buses, vital AC safeguard buses and loss of the AFW turbine-driven pump. With no secondary-side heat removal, core damage results at high RCS pressure. Phase II SAMAs 055, 061, and 062, to upgrade the ASSS to allow timely restoration of seal injection and cooling, to install a flood alarm in the 480VAC switchgear room, and to provide the capability of powering one SI pump or RHR pump using the Appendix R bus (MCC 312A) during control building flooding events, were evaluated.
NO_EXVESSEL-COOL	0.80	1.030	No ex-vessel cooling due to internal flooding event	This term represents failure of ex-vessel cooling following a flood in the control building switchgear room. Phase II SAMAs 006 and 007, to contain molten core debris in the reactor pit area and create a reactor cavity flooding system; Phase II SAMAs 032, 033, 035, and 037, to provide a diesel-driven pump for enhancing reactor vessel injection; Phase II SAMA 055, to provide the capability of powering one SI pump or RHR pump using the Appendix R bus (MCC 312A) during control building flooding events; and Phase II SAMAs 061 and 062, to upgrade the ASSS to allow timely restoration of seal injection and cooling and to install a flood alarm in the 480VAC switchgear room, were evaluated.

Table E.3-5
IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
DP-40	0.975	1.029	RCS pressure is low at vessel breach given a long-term internal flood induced SBO sequence	This term represents the probability that RCS depressurization occurs during a long-term internal flood induced SBO sequence. Phase I SAMAs to improve procedures to enhance the likelihood of success of operator action in response to accident conditions have already been implemented. Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.
H2_EARLY2_MED	0.50	1.026	In-vessel hydrogen production is medium (between 600 lbm and 2200 lbm)	This term represents the probability that the amount of hydrogen produced is between 600 lbm and 2200 lbm during accidents with 20% core melt, no early injection, and no late recirculation cooling. Phase II SAMA 009, to provide containment inerting capability to prevent combustion of hydrogen and carbon monoxide, was evaluated.
HPME_1	0.50	1.025	HPME occurs at high RCS pressure	This term represents the probability that HPME occurs at high RCS pressure. Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.

Table E.3-5
IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
BURN_VF1-E_DEF	0.50	1.021	Hydrogen burn occurs under medium hydrogen conditions	This term represents the probability of a hydrogen burn occurring at vessel failure, given a medium hydrogen concentration early, no prior early burns, and DCH. Phase II SAMA 009, to provide containment inerting capability to prevent combustion of hydrogen and carbon monoxide, was evaluated.
NO_QUENCH-3	1.0	1.019	No debris quench, given dry reactor pit and no late water supply after vessel breach	This term represents the probability that debris is not quenched immediately after vessel failure, with no water inside the reactor pit at vessel breach and no late water supply for debris cooling after vessel breach. Phase II SAMAs 006 and 007, to contain molten core debris in the reactor pit area and to create a reactor cavity flooding system, were evaluated.
NO_DISPERSAL	0.9	1.013	Core debris is not dispersed into containment atmosphere at vessel breach	This term represents the probability that debris is not dispersed and cooled following an HPME or an in-vessel or ex-vessel steam explosion event. Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.

Table E.3-5
IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
CFE@VF_2	0.997	1.013	Containment failure given containment pressure >23 psig, dry reactor pit, H2 burn and DCH	This term represents the probability that containment failure results from pressure rise at vessel failure given containment pressure greater than 23 psig, no water in the reactor pit, DCH, and hydrogen burn. Phase II SAMAs 007, 008, 009, 010, 011, 012, 013, and 014, for enhancing containment integrity, were evaluated. In addition, Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.
CFE@VF_9	0.24	1.0132	Containment failure given containment pressure >23 psig, dry reactor pit, and DCH	This term represents the probability that containment failure results from pressure rise at vessel failure given containment pressure greater than 23 psig, no water in the reactor pit, and DCH. Phase II SAMAs 007, 008, 009, 010, 011, 012, 013, and 014, for enhancing containment integrity, were evaluated. In addition, Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.
NO_QUENCH-2	0.50	1.010	No debris quench, given dry reactor pit and late water supply after vessel breach	This term represents the probability that debris is not quenched immediately after vessel failure, without water inside the reactor pit at vessel breach, but with a late water supply for debris cooling after vessel breach. Phase II SAMAs 006 and 007, to contain molten core debris in the reactor pit area and to create a reactor cavity flooding system, were evaluated.

Table E.3-5
IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
DP-44	0.10	1.009	RCS pressure is low at vessel breach given a small ISLOCA event.	This term represents the probability that RCS depressurization occurs during a small ISLOCA event. Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.
HPME_2	0.9	1.009	HPME occurs at medium RCS pressure	This term represents the probability that HPME occurs at RCS pressure between 675 psig and 2235 psig. Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.
CFE@VF_4	0.9	1.008	Containment failure given containment pressure < 23 psig, dry reactor pit, H2 burn and DCH	This term represents the probability that containment failure results from pressure rise at vessel failure given containment pressure less than 23 psig, no water in the reactor pit, DCH, and hydrogen burn. Phase II SAMAs 007, 008, 009, 010, 011, 012, 013, and 014, for enhancing containment integrity, were evaluated. In addition, Phase II SAMAs 038, 044 and 054, to enhance RCS depressurization systems, replace PORVs with larger ones, and provide DC power backup for the PORVs were evaluated.

Table E.3-5
IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
CFE_BURN2-H2_CFE	7.00E-02	1.005	Early hydrogen burn fails containment	This term represents the probability that an early hydrogen burn fails containment due to overpressure. Phase II SAMA 009, to provide containment inerting capability to prevent combustion of hydrogen and carbon monoxide, was evaluated. In addition, Phase II SAMAs 007, 008, 011, 012, 013, and 014, for enhancing containment integrity, were evaluated.
PDS_FRAC-31	9.17E-02	1.005	Long-term plant transient at medium RCS pressure	This term is the PDS split fraction for a long-term plant transient with secondary-side cooling available and RCS pressure between 675 psig and 2235 psig. The medium RCS pressure is a result of either a stuck-open PORV or RCP seal LOCA. Many Phase I SAMAs have been implemented to provide more reliable or diverse high or low pressure injection systems, enhance RCP seal cooling systems, and enhance procedures to cope with loss of CCW for RCP seal cooling. Phase II SAMAs 001, 002, and 003, to provide redundant RCP seal cooling, were evaluated.
NO-INVL-COOL-DEB	0.1	1.005	Coolable debris bed not formed in-vessel	This term represents the probability that a coolable debris bed is not formed in the reactor vessel, given that reactor vessel coolant injection has been recovered. Phase II SAMAs 032, 033, 034, 035, 036, and 037, for enhancing reactor vessel injection during transients, small LOCA and SBO were evaluated.

Table E.3-5
IP3 Correlation of Level II Risk Significant Terms to Evaluated SAMAs (Based on LERF)
(Continued)

Event Name	Probability	RRW	Event Description	Disposition
BURN_EARLY1_DEF	0.1	1.005	Hydrogen deflagration burn occurs	This term represents the probability that an early hydrogen burn occurs. Phase II SAMA 009, to provide containment inerting capability to prevent combustion of hydrogen and carbon monoxide, was evaluated. In addition, Phase II SAMAs 007, 008, 010, 011, 012, 013, and 014, for enhancing containment integrity, were evaluated.
REACTOR_PIT_WET	1.0	1.005	Water is present in the reactor pit	This flag event indicates that water is present in the reactor pit prior to vessel breach. The presence of water provides debris cooling and reduces the likelihood of DCH and core-concrete interactions (CCI). Phase II SAMA 007 was evaluated to provide cooling of the molten core before it causes vessel failure, enhance debris coolability, reduce CCI, and provide fission product scrubbing.

E.3.2.2 Radionuclide Analysis

This subsection provides the following information regarding the characterization of the Level 2 CET end states.

- Overview of PDS
- Overview of radionuclide removal processes and the concept of binning
- Identification of radionuclide release categories
- Release category bin assignments
- Process used to group the numerous source terms
- MAAP deterministic calculations to support CET end states definition
- Consequence analysis source terms

E.3.2.2.1 Overview of PDS

The interface between the Level 1 Systems Analysis and the Level 2 Containment Performance Analysis consists of a set of PDS. The PDS are defined by a set of functional characteristics for system operation, which are important to accident progression, containment failure and source term definition. Each PDS contains Level 1 sequences with sufficient similarity in system functional characteristics that the containment accident progression for all sequences in the group can be considered to be essentially the same. Each PDS defines a unique set of conditions regarding the state of the plant and containment building systems and the physical state of the core, reactor coolant system and the containment boundary at (approximately) the time of core damage or vessel failure. The important functional characteristics for each PDS were determined by defining the critical parameters (system functions), which impact the key results. The sequence characteristics that are important were defined by the requirements of the containment accident progression analysis. They include the type of accident initiator, the operability or non-operability of important systems, the value of important plant variables (e.g., primary system pressure) which are defined by system operation, and timing of key events.

Based on the above criteria, the Level 1 results were binned into 57 PDS. These PDS define important combinations of system states that can result in distinctly different accident progression pathways and therefore, different containment failure and source term characteristics. Table E.3-6 provides a description of the IP3 PDS that are used to summarize the Level 1 results.

The PDS designators listed in Table E.3-6 represent the core damage end state categories from the Level 1 analyses that are grouped together as entry conditions for the Level 2 analysis. The Level 2 accident progression for each of the PDS is then evaluated using a single CET to determine the appropriate release category for each Level 2 sequence. Each end state associated with a Level 2 sequence is assigned to a unique release category.

Table E.3-6
Summary of IP3 Internal Events PDS

Plant Damage State	Description	Frequency/ ry
PDS-1	Long-term small-break LOCA with subsequent loss of secondary cooling. The containment is not bypassed and AC power is available. Core damage proceeds at high RCS pressure (>2350psia). Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	2.12E-09
PDS-2	Same as PDS-1, except random faults fail the containment fan coolers.	0.00E+00
PDS-3	Same as PDS-1, except random faults fail the containment fan coolers and containment injection spray systems.	0.00E+00
PDS-4	Long-term medium or small LOCA with loss of recirculation cooling. Core damage results at medium RCS pressure (>675psia and <2350psia). Containment is not bypassed and AC power is available. Late vessel injection, secondary-side cooling, containment fan coolers and containment spray are available after the onset of core damage.	2.10E-06
PDS-5	Same as PDS-4, except random faults fail the containment fan coolers.	1.30E-10
PDS-6	Same as PDS-4, except random faults fail the containment fan coolers and containment injection spray system.	0.00E+00
PDS-7	Same as PDS-4, except random faults fail containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-8	Long-term medium LOCA. Although vessel injection is successful, random faults fail all modes of operation of the high-head recirculation core cooling systems. With no long-term core cooling, core damage proceeds at medium RCS pressure (>675psia and <2350psia). Containment is not bypassed and AC power is available. Late vessel injection, containment injection sprays and containment recirculation sprays are not available. However, secondary-side cooling and containment fan coolers are available after the onset of core damage.	2.95E-08
PDS-9	Same as PDS-8, except random faults fail containment fan coolers.	1.91E-09
PDS-10	Long-term medium LOCA with subsequent loss of secondary-side cooling and recirculation cooling. Core damage results at medium RCS pressure (> 675psia and < 2350psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	3.72E-11

Table E.3-6
Summary of IP3 Internal Events PDS
(Continued)

Plant Damage State	Description	Frequency/ ry
PDS-11	Same as PDS-10, except random faults fail the containment fan coolers and containment injection spray system.	0.00E+00
PDS-12	Same as PDS-10, except random faults fail containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-13	Long-term medium LOCA with subsequent random failure of secondary-side cooling and all modes of operation of the high-head recirculation core cooling systems. Core damage results at medium RCS pressure (> 675psia and < 2350psia). Containment is not bypassed and AC power is available. Late vessel injection is not available. Although containment fan coolers are available, both containment injection sprays and containment recirculation sprays are not available after the onset of core damage.	0.00E+00
PDS-14	Same as PDS-13, except random faults fail the containment fan coolers.	8.70E-11
PDS-15	Short-term large LOCA with either a loss of initial injection or loss of recirculation cooling. Core damage results at low RCS pressure (< 675 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment sprays are available after the onset of core damage.	2.19E-08
PDS-16	Same as PDS-15, except random faults fail the containment fan coolers.	0.00E+00
PDS-17	Same as PDS-15, except random faults fail the containment fan coolers and containment injection spray system.	0.00E+00
PDS-18	Same as PDS-15, except random faults fails containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-19	Short-term large LOCA. Although initial injection is successful, random faults fail both the recirculation pumps and RHR pumps for long-term recirculation cooling. Core damage results at low RCS pressure (< 675 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment injection spray and containment recirculation spray are not available. However, containment fan coolers are available after the onset of core damage.	0.00E+00
PDS-20	Same as PDS-19, except random faults fail the containment fan coolers.	1.09E-08

Table E.3-6
Summary of IP3 Internal Events PDS
(Continued)

Plant Damage State	Description	Frequency/ ry
PDS-21	Short-term ATWS event with AFW available and loss of long-term reactor subcriticality control. RCS pressure remains at the PORV setpoint, precluding high- and low-head safety injection. Therefore, core damage occurs in the short-term at high RCS pressure (> 2350 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	3.64E-07
PDS-22	Long-term transient involving loss of secondary cooling and subsequent loss of primary bleed-and-feed core cooling. Core damage results at high RCS pressure (> 2350 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment sprays are available after the onset of core damage.	3.30E-07
PDS-23	Same as PDS-22, except random faults fail the containment fan coolers.	5.25E-07
PDS-24	Same as PDS-22, except random faults fails the containment fan coolers and containment injection spray system.	0.00E+00
PDS-25	Long-term transient with a subsequent loss of secondary cooling. Following successful bleed-and-feed core cooling, failure to implement long-term recirculation cooling occurs. Core damage results at medium RCS pressure (> 675 psia and < 2350 psia). Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	2.42E-08
PDS-26	Same as PDS-25, except random faults fail the containment fan coolers.	3.53E-09
PDS-27	Same as PDS-25, except random faults fail the containment fan coolers and containment injection spray system.	0.00E+00
PDS-28	Same as PDS-25, except random faults fail containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-29	Long-term transient with subsequent loss of secondary cooling. Following successful bleed-and-feed core cooling, random faults fail long-term recirculation cooling. Core damage results at medium RCS pressure. Containment is not bypassed and AC power is available. Late vessel injection, containment injection spray and containment recirculation spray are unavailable after the onset of core damage. However, the containment fan coolers are available.	0.00E+00

Table E.3-6
Summary of IP3 Internal Events PDS
(Continued)

Plant Damage State	Description	Frequency/ ry
PDS-30	Same as PDS-29, except random faults fail the containment fan coolers.	5.54E-07
PDS-31	Long-term RCP seal LOCA caused by loss of CCW to the RCP seals. Core damage results at medium RCS pressure. Containment is not bypassed and AC power is available. Late vessel injection, containment fan coolers and containment spray are available after the onset of core damage.	1.05E-06
PDS-32	Same as PDS-31, except random faults fail the containment fan coolers.	1.68E-09
PDS-33	Same as PDS-31, except random faults fails containment fan coolers and containment injection spray system.	3.18E-10
PDS-34	Same as PDS-31, except random faults fails containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-35	Stuck open PORV with loss of long-term recirculation cooling. Core damage results at medium RCS pressure. Containment is not bypassed and AC power is available. Late vessel injection, containment injection spray and containment recirculation spray are unavailable after the onset of core damage. However, the containment fan coolers are available.	4.57E-10
PDS-36	Same as PDS-35, except random faults fail the containment fan coolers.	5.32E-08
PDS-37	SBO sequence in which a loss of all DC power occurs in the long term. No PORVs stick open. Secondary cooling by the AFW system is unavailable because the SBO renders both motor-driven AFW pumps inoperable, and the steam-turbine-driven AFW pump fails because of battery depletion or random faults. Without primary and secondary cooling, core damage occurs at high RCS pressure. Containment is not bypassed. All accident-mitigating functions are recoverable when offsite power is restored.	1.44E-09
PDS-38	Short-term SBO sequence with immediate loss of secondary cooling. Core damage results at high RCS pressure. Containment is not bypassed. All accident-mitigating functions are recoverable when offsite power is restored.	2.36E-08
PDS-39	Same as PDS-37, except RCS depressurization results from either operator action or a single PORV sticking open. Core damage results at medium RCS pressure. Containment is not bypassed. All accident-mitigating functions are recoverable when offsite power is restored.	6.25E-07

Table E.3-6
Summary of IP3 Internal Events PDS
(Continued)

Plant Damage State	Description	Frequency/ry
PDS-40	Short-term SBO sequence with immediate loss of secondary cooling and subsequent RCP seal LOCA or stuck-open PORV. Core damage results at medium RCS pressure. Containment is not bypassed. All accident-mitigating functions are recoverable when offsite power is restored.	2.47E-09
PDS-41	Short-term large LOCA induced by vessel rupture. The LOCA is beyond the capability of the ECCS. Core damage occurs in the short term with the RCS at low pressure. Vessel injection and all forms of containment heat removal (containment fan coolers, RHR heat exchangers, and containment sprays) are available. Containment is not bypassed and AC power is available.	1.34E-06
PDS-42	Same as PDS-41, except random faults fail the containment fan coolers.	1.10E-11
PDS-43	Same as PDS-41, except random faults fail the containment fan coolers and containment injection spray system.	0.00E+00
PDS-44	Same as PDS-41, except random faults fail the containment fan coolers, containment injection spray and containment recirculation spray systems.	0.00E+00
PDS-45	Long-term internal flood induced SBO sequence in which loss of AFW steam-turbine-driven pump occurs. With no secondary-side heat removal, core damage results at high RCS pressure. Because of the flood, core cooling and containment heat removal systems are unavailable after the onset of core damage. Containment is not bypassed	2.09E-06
PDS-46	Short-term internal flood induced SBO sequence in which loss of secondary heat removal occurs. Core damage results at high RCS pressure. Because of the flood, core cooling and containment heat removal systems are not available after the onset of core damage	1.55E-07
PDS-47	Long-term internal flood induced SBO with a subsequent stuck-open PORV or RCP seal LOCA. Core damage ensues at medium RCS pressure. The steam-turbine-driven AFW pump is available after core damage. However, core cooling and containment heat removal systems are unavailable because of the internal flooding event. The containment is not bypassed	0.00E+00
PDS-48	Short-term internal flood induced SBO sequence in which loss of secondary heat removal occurs and a subsequent breach of RCS integrity occurs because of a stuck-open PORV or RCP seal LOCA. Core damage results at medium RCS pressure. Because of the flood, core cooling and containment heat removal systems are not available after the onset of core damage	0.00E+00

Table E.3-6
Summary of IP3 Internal Events PDS
(Continued)

Plant Damage State	Description	Frequency/ ry
PDS-49	Long-term small break ISLOCA outside containment. Core damage results at medium RCS pressure with a bypassed containment. While vessel injection and all modes of containment sprays are unavailable, containment fan coolers are available after core damage.	8.79E-08
PDS-50	Short-term large break ISLOCA outside containment. Core damage results at low RCS pressure with a bypassed containment. While vessel injection and all modes of containment spray are unavailable, containment fan coolers are available after core damage.	4.45E-08
PDS-51	SGTR and failure to isolate the ruptured steam generator. Because RCS pressure remains above the ruptured steam generator pressure, water lost from the RCS does not return to the containment sump and recirculation core cooling is unavailable. Core damage results at medium RCS pressure with a bypassed containment. While vessel injection and all modes of containment sprays are unavailable, containment fan coolers are available after core damage.	7.72E-07
PDS-52	Same as PDS-51, except random faults fail containment fan coolers.	0.00E+00
PDS-53	Same as PDS-51, except random faults fail AFW to the steam generators and the containment fan coolers.	0.00E+00
PDS-54	Same as PDS-51, except the ruptured steam generator is isolated.	9.84E-07
PDS-55	Same as PDS-51 except the ruptured steam generator is isolated and random faults fail the containment fan coolers.	2.35E-09
PDS-56	Same as PDS-51, except the ruptured steam generator is isolated and random faults fail AFW to the steam generators.	2.71E-07
PDS-57	Same as PDS-51, except the ruptured steam generator is isolated, random faults fail AFW to the steam generators and the containment fan coolers.	2.79E-10
	Total	**1.15E-5**

E.3.2.2.2 Overview of Radionuclide Removal Processes and Concept of Binning

A major feature of a Level 2 analysis is the estimation of the source term for every possible outcome of the CET. The CET end points represent the outcomes of possible in-containment accident progression sequences. These end points represent complete severe accident sequences from initiating event to release of radionuclides to the environment. The Level 1 and plant system information is passed through to the CET evaluation in discrete PDS. An atmospheric source term may be associated with each of these CET sequences. Because of the large number of postulated accident scenarios considered, mechanistic calculations (i.e., MAAP calculations) are not performed for every end-state in the CET. Rather, accident sequences produced by the CET are grouped or "binned" into a limited number of release categories, each of which represents all postulated accident scenarios that would produce a similar fission product source term.

The criteria used to characterize the release are the estimated magnitude of total release and the timing of the first significant release of radionuclides. The predicted source term associated with each release category, including both the timing and magnitude of the release, is determined using the results of MAAP calculations.

E.3.2.2.3 Identification of Radionuclide Release Categories

E.3.2.2.3.1 Timing of Release

Timing completely governs the extent of radioactive decay of short-lived radioisotopes prior to an offsite release and, therefore, has a first-order influence on immediate health effects. IP3 characterizes the release timing relative to the time at which the release begins, measured from the time of accident initiation. Two timing categories are used, as follows.

(1) Early: rapid, unmitigated release of airborne fission products from the containment to the environment occurring before the effective implementation of offsite emergency response and protective actions. This involves CET endstates in which containment failure occurs within 0 to 12 hours from the initiating event.

(2) Late: mitigated release of airborne fission products from the containment to the environment occurring after effective implementation of offsite emergency response and protective actions. This involves CET endstates in which containment failure occurs after 12 hours from the initiating event.

The definition of the release category timing takes into consideration the compensatory measures available to reduce or prevent dose to the public and the characteristics of the radionuclide release. Compensatory measures are prescribed in the emergency response plan. These actions, which are routinely practiced, are geared to mobilizing utility resources to implement emergency procedures, assess the potential offsite consequence of an accident, and recommend to government officials appropriate action for protecting the public (evacuate or shelter).

An evacuation time estimates study performed for the Indian Point Energy Center (IPEC) site [Reference E.3-7] examined 14 evacuation scenarios under which evacuation times are calculated to successfully evacuate 100 percent of the general public. The ranges of times for those 14 scenarios for the following emergency planning zone rings (shortest to longest in hours: minutes) are as follows:

2 miles:	4:30 to 6:50;
5 miles:	5:25 to 8:00;
10 miles:	7:10 to 12:00.

Since the 10-mile emergency planning zone may not be evacuated for 12 hours from the initiating event, 12 hours is the upper bound time in which an early release can occur.

E.3.2.2.3.2 Magnitude of Release

Source term results from previous risk studies suggest that categorization of release magnitude based on cesium iodide (CsI) release fractions alone are appropriate [Reference E.3-5]. The CsI release fraction indicates the fraction of in-vessel radionuclides escaping to the environment. (Noble gas release levels are non-informative since release of the total core inventory of noble gases is essentially complete given containment failure.)

The source terms were grouped into five distinct radionuclide release categories or bins according to release magnitude as follows.

(1) High: A radionuclide release of sufficient magnitude to have the potential to cause early fatalities. This implies a total integrated release of > 10% of the initial core inventory of Cesium Iodide (CsI) [Reference E.3-5][1].

(2) Medium: A radionuclide release of sufficient magnitude to cause near-term health effects. This implies a total integrated release of between 1% and 10% of the initial core inventory of CsI [Reference E.3-5][2].

(3) Low: A radionuclide release with the potential for latent health effects. This implies a total integrated release of between 0.1% and 1% of the initial core inventory of CsI.

(4) Low-Low: A radionuclide release with undetectable or minor health effects over most of the population. This implies a total integrated release of between 0.01% and 0.1% of the initial core inventory of CsI.

1. Once the CsI source term exceeds 0.1, the source term is large enough that doses above the early fatality threshold can sometimes occur within a population center a few miles from the site.

2. The reference document indicates that for CsI release fractions of 1 to 10 percent, the number of latent fatalities is found to be at least 10 percent of the latent fatalities for the highest release.

(5) Negligible or no containment failure (NCF): A radionuclide release that is less than or equal to the containment design base leakage. This implies total integrated release of < 0.01% of the initial core inventory of CsI.

E.3.2.2.4 Release Category Bin Assignments

The combination of release magnitude and timing produce nine distinct release categories. Table E.3-7 summarizes the scheme used to bin CET sequences with respect to magnitude of release, based on the predicted CsI release fraction and release timing.

Table E.3-7
IP3 Release Severity and Timing Classification Scheme Summary

Release Severity		**Release Timing**	
Classification Category	**Percent CsI Release**	**Classification Category**	**Time of Initial Release From Accident Initiation**
High	Greater than 10	Early (E)	Less than 12 hours
Medium	1 to 10		
Low	0.1 to 1	Late (L)	Greater than 12 hours
Low-Low	0.01 to 0.1		
NCF	Less than <0.01		

E.3.2.2.5 Process Used to Group the Source Terms

The approach used to evaluate radionuclide releases and develop release categories is similar to that applied in the NUREG-1150 analysis; i.e., a source term was associated with each CET end-state that was found to have a significant frequency. The objectives were to establish the timing of the first significant release of radionuclides and estimate the magnitude of the total release.

The first step in the source term assessment effort was to identify the sequence characteristics that are most important for defining the source term. These characteristics were identifiable from the PDS characteristics and from the CET sequence characteristics since one of the primary objectives in the PDS grouping and CET evaluation was to define those events and conditions most important for source term assessment. The set of sequence characteristics important to source term assessment was used as grouping criteria to define the release categories and the associated source term magnitude, composition and timing.

The containment sequence characteristics selected for use in definition of the IP3 source term release categories are

- vessel breach,
- containment failure,
- CCI,
- fission product removal, and
- PAB retention.

The goal of the grouping process was to develop the minimum number of release categories necessary to distinguish the important combinations of sequence characteristics that can result in distinctly different atmospheric source terms.

The second step was to classify the various progressions paths in the IP3 CET as unique release end states based on the sequence characteristics. The release modes were categorized into the following general classifications:

- end states are recovered in-vessel (no vessel breach),
- end states are recovered ex-vessel (vessel breach, but no core-concrete interactions),
- end states are late containment failures, and
- end states are early containment failures.

Each CET end state represents a particular release event or a recovered, degraded core state that may be characterized according to its potential for fission product release to the atmosphere, its timing of release initiation relative to time of incipient core damage, and its release duration.

Table E.3-8 summarizes the possible CET release categories for the spectrum of core melt accident sequences. This table defines the various CET release modes as early or late release events and containment damage states (i.e., failure modes), including recovered states and release mechanisms (i.e., no CCI). Each release mode represents a release path from the fuel through the primary coolant system and the containment atmosphere to the environment, should the containment ultimately fail or be bypassed. The release path (including the associated removal mechanism) is related to a particular environmental source term.

The consolidation of source term results for the CET release categories presented in Table E.3-8 was accomplished by "binning" or grouping releases into release categories that represent all postulated accident scenarios that produce a similar fission product source term. The criteria used to characterize the release are the estimated magnitude of total release and the timing of the first significant release of radionuclides.

Based on the above binning methodology, the salient Level 2 results are summarized in Table E.3-9. This table identifies the total annual release frequency for each Level 2 release category.

Table E.3-8
Description of IP3 CET Release Modes

Accident Progression Bin	CET Sequence Description	Release Timing (based on MAAP)	Release Magnitude (based on MAAP)	CET Release Category
APB-1	Recovered in-vessel, no vessel breach, no containment failure	NA	Negligible	NCF
APB-2	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early Low
APB-3	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release not mitigated	Early	Medium	Early Medium
APB-4	Vessel breach at low pressure, recovered ex-vessel, no containment failure	NA	Negligible	NCF
APB-5	Vessel breach at low pressure, recovered ex-vessel, late containment leak failure, in-vessel fission product release mitigated	Late	Low-Low	Late Low-Low
APB-6	Vessel breach at low pressure, recovered ex-vessel, late containment leak failure, in-vessel fission product release not mitigated	Late	Medium	Late Medium
APB-7	Vessel breach at low pressure, recovered ex-vessel, late containment rupture failure, in-vessel fission product release not mitigated	Late	High	Late High
APB-8	Vessel breach at low pressure, CCI occurs, no containment failure	NA	Negligible	NCF
APB-9	Vessel breach at low pressure, CCI occurs, late containment leak failure, ex-vessel fission product release mitigated by overlying pool, in-vessel release mitigated by sprays	Late	Low-Low	Late Low-Low

Table E.3-8
Description of IP3 CET Release Modes
(Continued)

Accident Progression Bin	CET Sequence Description	Release Timing (based on MAAP)	Release Magnitude (based on MAAP)	CET Release Category
APB-10	Vessel breach at low pressure, CCI occurs, late containment rupture failure, ex-vessel fission product release mitigated by overlying pool, in-vessel release mitigated by sprays	Late	Low	Late Low
APB-11	Vessel breach at low pressure, CCI occurs, late containment leak failure, ex-vessel fission product release mitigated by overlying pool, in-vessel release not mitigated	Late	Medium	Late Medium
APB-12	Vessel breach at low pressure, CCI occurs, late containment rupture failure, ex-vessel fission product release mitigated by overlying pool, in-vessel release not mitigated	Late	High	Late High
APB-13	Vessel breach at low pressure, no CCI, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early Low
APB-14	Vessel breach at low pressure, no CCI, early containment rupture failure, in-vessel fission product release mitigated	Early	Medium	Early Medium
APB-15	Vessel breach at low pressure, no CCI, early containment leak failure, in-vessel fission product release not mitigated	Early	High	Early High
APB-16	Vessel breach at low pressure, no CCI, early containment rupture failure, in-vessel fission product release not mitigated	Early	High	Early High
APB-17	Vessel breach at low pressure, significant CCI occurs, early containment leak failure, in- and ex-vessel product release mitigated	Early	Low	Early Low

Table E.3-8
Description of IP3 CET Release Modes
(Continued)

Accident Progression Bin	CET Sequence Description	Release Timing (based on MAAP)	Release Magnitude (based on MAAP)	CET Release Category
APB-18	Vessel breach at low pressure, significant CCI occurs, early containment rupture failure, in- and ex-vessel product release mitigated	Early	Medium	Early Medium
APB-19	Vessel breach at low pressure, significant CCI occurs, early containment leak failure, ex-vessel product release mitigated by overlying pool, in-vessel fission product release not mitigated	Early	High	Early High
APB-20	Vessel breach at low pressure, significant CCI occurs, early containment rupture failure, ex-vessel product release mitigated by overlying pool, in-vessel fission product release not mitigated	Early	High	Early High
APB-21	Recovered in-vessel, no vessel breach, no containment failure	NA	Negligible	NCF
APB-22	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early-Low
APB-23	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release not mitigated	Early	Medium	Early-Medium
APB-24	Vessel breach at low pressure, recovered ex-vessel, no containment failure	NA	Negligible	NCF
APB-25	Vessel breach at low pressure, no CCI, late containment leak failure, in-vessel fission product release mitigated by sprays	Late	Low-Low	Late Low-Low
APB-26	Vessel breach at low pressure, no CCI, late containment rupture failure, in-vessel fission product release mitigated by sprays	Late	Low	Late Low

Table E.3-8
Description of IP3 CET Release Modes
(Continued)

Accident Progression Bin	CET Sequence Description	Release Timing (based on MAAP)	Release Magnitude (based on MAAP)	CET Release Category
APB-27	Vessel breach at low pressure, no CCI, late containment leak failure, in-vessel fission product release not mitigated	Late	Medium	Late Medium
APB-28	Vessel breach at low pressure, no CCI, late containment rupture failure, in-vessel fission product release not mitigated	Late	High	Late High
APB-29	Vessel breach at low pressure, CCI occurs, no containment failure	NA	Negligible	NCF
APB-30	Vessel breach at low pressure, significant CCI occurs, late containment leak failure, in- and ex-vessel fission product release mitigated by sprays	Late	Low-Low	Late Low-Low
APB-31	Vessel breach at low pressure, significant CCI occurs, late containment rupture failure, in- and ex-vessel fission product release mitigated by sprays	Late	Low	Late Low
APB-32	Vessel breach at low pressure, significant CCI occurs, late containment leak failure, in- and ex-vessel fission product release not mitigated	Late	Medium	Late Medium
APB-33	Vessel breach at low pressure, significant CCI occurs, late containment rupture failure, in- and ex-vessel fission product release not mitigated	Late	High	Late High
APB-34	Vessel breach at low pressure, no CCI, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early Low
APB-35	Vessel breach at low pressure, no CCI, early containment rupture failure, in-vessel fission product release mitigated	Early	Medium	Early Medium

Table E.3-8
Description of IP3 CET Release Modes
(Continued)

Accident Progression Bin	CET Sequence Description	Release Timing (based on MAAP)	Release Magnitude (based on MAAP)	CET Release Category
APB-36	Vessel breach at low pressure, no CCI, early containment leak failure, in-vessel fission product release not mitigated	Early	High	Early High
APB-37	Vessel breach at low pressure, no CCI, early containment rupture failure, in-vessel fission product release not mitigated	Early	High	Early High
APB-38	Vessel breach at low pressure, significant CCI occurs, early containment leak failure, in- and ex-vessel fission product release mitigated by sprays	Early	Low	Early Low
APB-39	Vessel breach at low pressure, significant CCI occurs, early containment rupture failure, in- and ex-vessel fission product release mitigated by sprays	Early	Medium	Early Medium
APB-40	Vessel breach at low pressure, significant CCI occurs, early containment leak failure, fission product not mitigated	Early	High	Early High
APB-41	Vessel breach at low pressure, significant CCI occurs, early containment rupture failure, fission product not mitigated	Early	High	Early High
APB-42	Recovered in-vessel, no vessel breach, no containment failure	NA	Negligible	NCF
APB-43	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release mitigated	Early	Low	Early Low
APB-44	Recovered in-vessel, no vessel breach, early containment leak failure, in-vessel fission product release not mitigated	Early	Medium	Early Medium

Table E.3-8
Description of IP3 CET Release Modes
(Continued)

Accident Progression Bin	CET Sequence Description	Release Timing (based on MAAP)	Release Magnitude (based on MAAP)	CET Release Category
APB-45	Vessel breach at high pressure, CCI occurs, no containment failure	NA	Negligible	NCF
APB-46	Vessel breach at high pressure, no CCI, late containment leak failure, in-vessel and late fission product release mitigated by sprays	Late	Low	Late Low
APB-47	Vessel breach at high pressure, no CCI, late containment rupture failure, in-vessel and late fission product release mitigated by sprays	Late	Low	Late Low
APB-48	Vessel breach at high pressure, no CCI, late containment leak failure, in-vessel and late fission product release not mitigated	Late	Medium	Late Medium
APB-49	Vessel breach at high pressure, no CCI, late containment rupture failure, in-vessel and late fission product release not mitigated	Late	High	Late High
APB-50	Vessel breach at high pressure, CCI occurs, no containment failure	NA	Negligible	NCF
APB-51	Vessel breach at high pressure, moderate CCI occurs, late containment leak failure, in- and ex-vessel fission product release mitigated by Sprays	Late	Low	Late Low
APB-52	Vessel breach at high pressure, moderate CCI occurs, late containment rupture failure, in- and ex-vessel fission product release mitigated by Sprays	Late	Low	Late Low
APB-53	Vessel breach at high pressure, moderate CCI occurs, late containment leak failure, in- and ex-vessel, fission product release not mitigated	Late	Medium	Late Medium

Table E.3-8
Description of IP3 CET Release Modes
(Continued)

Accident Progression Bin	CET Sequence Description	Release Timing (based on MAAP)	Release Magnitude (based on MAAP)	CET Release Category
APB-54	Vessel breach at high pressure, moderate CCI occurs, late containment rupture failure, in- and ex-vessel, fission product release not mitigated	Late	High	Late High
APB-55	Vessel breach at high pressure, no CCI, early containment leak failure, in-vessel and late fission product release mitigated	Early	Medium	Early Medium
APB-56	Vessel breach at high pressure, no CCI, early containment rupture failure, in-vessel and late fission product release mitigated	Early	Medium	Early Medium
APB-57	Vessel breach at high pressure, no CCI, early containment leak failure, in-vessel and late fission product release not mitigated	Early	Medium	Early Medium
APB-58	Vessel breach at high pressure, no CCI, early containment rupture failure, in-vessel and late fission product release not mitigated	Early	High	Early High
APB-59	Vessel breach at high pressure, moderate CCI occurs, early containment leak failure, in- and ex-vessel fission product release mitigated by sprays	Early	Medium	Early Medium
APB-60	Vessel breach at high pressure, moderate CCI occurs, early containment rupture failure, in- and ex-vessel fission product release mitigated by sprays	Early	Medium	Early Medium
APB-61	Vessel breach at high pressure, moderate CCI occurs, early containment leak failure, ex-vessel and late fission product release not mitigated	Early	Medium	Early Medium
APB-62	Vessel breach at high pressure, moderate CCI occurs, early containment rupture failure, ex-vessel and late fission product release not mitigated	Early	High	Early High

Table E.3-9
Summary of CET Quantification
IP3 PSA Model Revision 2

Release Category (Timing/Magnitude)	Release Frequency (Per year)
Late Low-Low	5.66E-08
Late Low	3.75E-07
Late Medium	2.01E-06
Late High	4.23E-07
Early Low-Low	0.00E+00
Early Low	1.46E-07
Early Medium	1.24E-06
Early High	9.43E-07
No Containment Failure (NCF)	6.30E-06
Total	**1.15E-05**

Nomenclature

Timing:

Late - Greater than 12 hours
Early - Less than 12 hours

Magnitude

NCF (Little to no release) - Less than 0.01% Cs Iodide
Low-Low - 0.01% to 0.1% Cs Iodide
Low - 0.1% to 1% Cs Iodide
Medium - 1% to 10% Cs Iodide
High - Greater than 10% Cs Iodide

E.3.2.2.6 MAAP Deterministic Calculations to Support CET End States Definition

The MAAP computer code is used to assign both the radionuclide release magnitude and timing based on the accident progression characterization. Specifically, MAAP provides the following information:

- containment pressure and temperature (time of containment failure is determined by comparing these values with the nominal containment capability);
- radionuclide release timing and magnitude for a large number of radioisotopes; and
- release fractions for twelve radionuclide species.

E.3.2.2.7 Consequence Analysis Source Terms

Input to the Level 3 IP3 model from the Level 2 model is a combination of radionuclide release fractions, timing of radionuclide releases, and frequencies at which the releases occur. This combination of information is used in conjunction with IP3 site characteristics in the Level 3 model to evaluate the offsite consequences of a core damage event.

Source terms were developed for the nine release categories identified in Table E.3-9. The MAAP computer code was used to generate the radionuclide release magnitude for the MACCS2 consequence analysis [Reference E.3-6]. The MAAP calculations are representative deterministic thermal hydraulic calculations that portray dominant CET scenarios.

Table E.3-10 provides a summary of the Level 2 results that were used as Level 3 input for the IP3 SAMA analysis.

The source terms presented in Table E.3-10 and used in the consequence analysis were determined as follows:

1. The appropriate MAAP case source terms were selected and assigned to a particular CET accident progression endstate.
2. Based on the source terms from Step 1, the source terms for each plant damage state CET accident progression endstate were determined.
3. The frequency of each release category was determined by summing the individual plant damage state CET accident progression endstates contained in the particular release category (i.e., no containment failure, early high release, etc.).
4. The release category individual fractional contributions for each CET accident progression were determined by dividing the result from Step 3 by the individual PDS frequencies.

5. Each PDS accident progression CET endpoint source terms, release timing, release energy and release elevation was multiplied by the value determined in Step 4.

6. The individual results of Step 5 were summed to arrive at the total final values contained in Table E.3-10.

Table E.3-10
IP3 Release Category Source Terms

	Release Characterization	Frequency (/ry)	Warning Time (sec)	Elevation (m)	Release Start (Hours)	Release Duration (Hours)	Release Energy (W)
1	NCF	6.30E-06	1.26E+04	3.00E+01	0.00E+00	3.54E+01	9.20E+05
2	Early High	9.43E-07	1.27E+04	3.00E+01	3.34E+00	2.20E+01	1.03E+06
3	Early Medium	1.24E-06	9.18E+03	3.00E+01	2.56E+00	2.28E+01	1.07E+06
4	Early Low	1.46E-07	9.31E+03	3.00E+01	2.75E+00	2.36E+01	1.11E+06
5	Early Low-Low	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
6	Late High	4.23E-07	5.58E+03	3.00E+01	2.05E+01	3.60E+01	9.20E+05
7	Late Medium	2.01E-06	7.17E+03	3.00E+01	2.14E+01	3.60E+01	9.20E+05
8	Late Low	3.75E-07	2.19E+04	3.00E+01	2.53E+01	3.60E+01	9.20E+05
9	Late Low-Low	5.66E-08	2.56E+04	3.00E+01	3.15E+01	3.60E+01	9.20E+05

Table E.3-10
IP3 Release Category Source Terms
(continued)

	Release Fractions								
	NG	I	Cs	Te	Sr	Ru	La	Ce	Ba
1	9.62E-05	6.51E-06	2.65E-06	2.08E-06	6.09E-08	5.20E-07	3.26E-09	2.72E-08	1.79E-07
2	6.35E-01	1.63E-01	1.48E-01	1.47E-01	1.57E-02	6.48E-02	5.55E-04	3.03E-03	3.07E-02
3	9.87E-01	1.31E-02	1.18E-02	2.65E-02	8.51E-04	2.95E-02	5.17E-05	3.07E-04	1.95E-02
4	2.43E-01	2.03E-03	1.62E-03	2.90E-03	8.98E-05	2.97E-03	5.17E-06	3.11E-05	1.87E-03
5	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
6	9.89E-01	1.17E-01	2.26E-02	4.81E-03	2.08E-04	3.74E-03	1.32E-05	1.22E-04	9.06E-04
7	8.23E-01	1.53E-02	4.30E-03	1.49E-03	8.01E-05	1.44E-03	5.11E-06	4.72E-05	3.50E-04
8	6.98E-01	1.06E-03	7.91E-04	1.23E-03	8.69E-05	3.47E-06	2.59E-06	2.38E-05	7.41E-05
9	9.09E-01	8.14E-04	6.96E-04	7.55E-04	3.63E-05	2.08E-06	1.14E-06	1.20E-05	3.33E-05

E.3.3 IPEEE Analysis

E.3.3.1 Seismic Analysis

The seismic portion of the IPEEE was completed in conjunction with the SQUG program [References E.3-8 and E.3-9]. IP3 performed a seismic probabilistic risk assessment (PRA) following the guidance of NUREG-1407 [Reference E.3-10] and NUREG/CR-2300 [Reference E.3-11]. The seismic PRA logic model was developed using a fault tree linking approach similar to the Level 1 PSA. This approach permits the explicit modeling of system and component dependencies that exist between event tree top events. The seismic PRA also includes a simplified containment performance model, which was developed to address scenarios leading to significant early containment releases during a seismic event. The seismic PRA provides quantitative, but conservative results. Therefore, its results should not be compared directly with the best-estimate internal events results.

Conservative assumptions in the seismic PRA include the following:

- Each of the sequences in the seismic PRA assumes unrecoverable loss of offsite power. If offsite power was maintained, or recovered, following a seismic event, there would be many more systems available to maintain core cooling and containment integrity than are presently credited in the analysis.

- A single, conservative, surrogate element whose failure leads directly to core damage is used in the seismic risk quantification to model the most seismically rugged components.

- Because there is little industry experience with crew actions following seismic events, human actions were conservatively characterized.

The conclusions of the IP3 seismic PRA are as follows.

- The total seismic CDF for IP3 is 4.4 x 10-5/year.

- No unique decay heat removal vulnerabilities to seismic events were found because the safety-related systems provide effective and reliable means for reactor reactivity control, electrical power, RCS pressure control, decay heat removal, and containment pressure control.

- Seismic-induced flooding and fires do not pose major risks.

- No unique seismic-induced containment failure mechanisms were identified.

The seismic PRA CDF has recently been re-evaluated to reflect updated random component failure probabilities and to model recovery of onsite power and local operation of the turbine-driven AFW pump. The revised seismic CDF of 2.65×10^{-5} per reactor-year represents a reduction by a factor of 1.67 from the IPEEE. This revised seismic CDF was used to determine the external event multiplier described in Section 4.21.5.4.

One plant improvement is identified in Table 2.4 of NUREG-1742 [Reference E.3-12]. To address the potential spurious operation of the EDG room carbon dioxide (CO2) system and subsequent shutdown of the EDG ventilation system during a seismic event, a plant modification installed a QA category I, seismic class I, actuation permission auxiliary control panel for CO2 discharge into the EDG building. Since shutdown of EDG ventilation due to spurious operation of the EDG room carbon dioxide (CO2) system during a seismic event is not considered in the seismic PRA model, the seismic CDF was not impacted by this modification.

E.3.3.2 Fire Analysis

The IP3 internal fire risk model was performed in 1997 as part of the IPEEE submittal report [Reference E.3-8]. The IP3 fire analysis was performed using EPRI's Fire PRA Implementation Guide [Reference E.3-13]. The EPRI Fire Induced Vulnerability Evaluation method was used for the initial screening, for treatment of transient combustibles, and as the source of fire frequency data [Reference E.3-14].

Table E.3-11 presents the results of the IP3 IPEEE fire analysis and the updated values used in this SAMA evaluation. The IPEEE values presented in Table E.3-11 are the same as those listed in NUREG-1742 [Reference E.3-12]. These values reflect the re-evaluation of the IPEEE fire CDF results to include response to Nuclear Regulatory Commission (NRC) questions and issues regarding fire-modeling progression.

A number of plant improvements were identified and are described in NUREG-1742, *Perspectives Gained from the IPEEE Program*, Final Report, April 2002. These improvements have been implemented. In addition, a number of administrative procedures were revised to improve combustible and flammable material control.

The revised fire CDF of 2.55×10^{-5} per reactor-year, which reflects these plant improvements and results in a reduction factor of 2.19, was used to determine the external event multiplier described in Section 4.21.5.4.

E.3.3.2.1 Risk Reduction for Dominant Fire Zones

Table E.3-11 lists a number of fire zones with CDF values above 1E-06 per year. The IPEEE recommendations to restore the 480VAC switchgear room carbon dioxide suppression system to automatic actuation, and realign the power supplies and reroute the cables for the EDG fans and engine auxiliaries have been implemented, and are reflected in the revised CDF values in Table E.3-11.

Other improvements implemented include

- restraining flammables or maintaining them in cabinets,

- monitoring and controlling the quantity of combustible materials in critical process areas, and
- monitoring and controlling the pre-staging of outage materials.

Although not explicitly credited in the model, credit for these controls would reduce CDF values for all of the dominant zones.

The following discussion for each dominant zone explains what measures have been taken to reduce risk in that zone and explains why the fire CDF cannot be further reduced in a cost effective manner.

480VAC Switchgear Room (Fire Zone 14)

The switchgear room is equipped with fire detection, which is annunciated in the control room, and an automatic full flooding CO2 fire suppression system. This system can also be manually actuated by the fire brigade from the 15-foot elevation of the turbine building. This zone is also regularly inspected by operations personnel who are trained fire brigade members, as well as by plant security officers.

At the time of the IPEEE, the CO2 system had been placed in "Manual" due to seismic interaction issues. Subsequently, the system was extensively modified and restored to automatic operation. Additionally, a more realistic assessment was made of the standby instrument air compressor run time. The IPEEE analysis assumed both air compressors running at all times. In reality, the standby air compressor will only run during scheduled maintenance of the 33 instrument air compressor (approximately 5 days/year) and rare system perturbations. Therefore, a conservative run time of 10 percent was assigned to the standby air compressor. Accordingly, restoration of automatic fire suppression capability, along with refinements in the updated PSA model, resulted in the revised fire zone CDF in Table E.3-11.

Since the switchgear room is equipped with a detection system that alarms in the control room and an automatic carbon dioxide suppression system, no further cost-effective changes were identified to reduce CDF in this zone.

Cable Spreading Room (Fire Zone 11)

The cable spreading room is equipped with fire detection, which is annunciated in the control room, and an automatic full flooding CO2 fire suppression system. This system can also be manually actuated by the fire brigade. This zone is also regularly inspected by operations personnel who are trained fire brigade members, as well as by plant security officers. The reduction in the zone CDF was realized by re-evaluating high CDF scenarios based on a re-assessment of equipment lost as a result of postulated fire induced damage and applicable initiating events.

Based on the above, no further cost-effective changes were identified to reduce CDF in this zone.

Central Control Room (Fire Zone 15)

The main control room is continuously inhabited by operations personnel, who are trained fire brigade members, ensuring prompt fire detection and manual suppression. Therefore, no further cost-effective changes were identified to reduce CDF in this zone.

480VAC Switchgear Room / South Turbine Building (Fire Zones 14 / 37A)

A fire initiating in zone 14 and propagating to zone 37A was the only multiple compartment fire which exceeded the IP3 IPEEE screening criteria. At the time of the IPEEE, the 480VAC switchgear room CO2 suppression system had been placed in "Manual" due to seismic interaction issues. Subsequently, the system was extensively modified and restored to automatic operation. Accordingly, restoration of automatic fire suppression capability, along with refinements in the updated PSA model in fire zone 14, resulted in the revised fire zone CDF in Table E.3-11.

Since the switchgear room is equipped with a detection system that alarms in the control room and an automatic full flooding carbon dioxide suppression system, no further cost-effective changes were identified to reduce CDF in this zone.

31, 32, & 33 EDG Cells (Fire Zones 10, 101A, & 102A)

The EDG cells are equipped with fire detection, which is annunciated in the control room, and an automatic full flooding CO2 fire suppression system. This system can also be manually actuated by the fire brigade. This zone is also regularly inspected by operations personnel who are trained fire brigade members, as well as by plant security officers.

The IPEEE identified vulnerability with the EDG exhaust fans and engine auxiliaries' cable routing which could result in failure of multiple EDGs due to a fire in a single cell. Subsequently, the power supplies and cables for the EDG fans and engine auxiliaries were realigned and re-routed to eliminate this failure mechanism. As reflected in Table E.3-11, this resulted in a significant reduction in the CDF for these fire zones.

EDG cells are equipped with a fire detection system that alarms in the control room and an automatic full flooding carbon dioxide suppression system, and the recommendations of the IP3 IPEEE have been implemented. Therefore, no further cost-effective changes were identified to reduce CDF in these zones.

E.3.3.3 Other External Hazards

The IP3 IPEEE submittal, in addition to the internal fires and seismic events, examined a number of other external hazards:

- high winds and tornadoes;
- external flooding; and
- ice, hazardous chemical, transportation, and nearby facility incidents.

No risks to the plant occasioned by high winds and tornadoes, external floods, ice, and hazardous chemical, transportation, and nearby facility incidents were identified that might lead to core damage with a predicted frequency in excess of 10^{-6}/year. Therefore, these other external event hazards are not included in this attachment and are not expected to impact the conclusions of this SAMA evaluation.

However, scenarios involving hydrogen explosions within the turbine building, the pipe trench between the PAB and containment, the hydrogen shed area in the containment access facility, and the pipe chase on the 73-ft elevation of the north-east corner of the PAB were identified that, in total, could result in core damage with a conservatively estimated frequency slightly above $10^{-6/}$year. Therefore, Phase II SAMA 053 is used to evaluate the change in plant risk from plant modifications to install an excess flow valve to reduce the risk associated with hydrogen explosions inside the turbine building or PAB.

Table E.3-11
IP3 Updated Fire CDF Results

Fire Zone	Fire Zone Description	CDF/year	Revised CDF/year
14	480V switchgear room	3.51E-05	1.31E-05
11	cable spreading room	6.83E-06	5.26E-06
15	control room	3.65E-06	3.65E-06
14/37A	480V switchgear room / south turbine building	4.49E-06	1.80E-07
10	diesel generator 31	2.13E-06	2.01E-06
102A	diesel generator 33	1.93E-06	4.68E-09
60A	upper electrical tunnel	7.14E-07	7.14E-07
101A	diesel generator 32	3.38E-07	5.15E-09
7A	lower electrical tunnel	2.78E-07	2.78E-07
23	auxiliary feedwater pump room	2.28E-07	2.28E-07
37A	south turbine building elevation 15 ft	3.78E-08	3.78E-08
17A	primary auxiliary building (PAB) corridor	3.17E-8	3.17E-08

E.3.4 PSA Model Revisions and Peer Review Summary

The summary of the IP3 PSA models CDF and LERF is presented in the table below.

Summary of Major PSA Models		
Model	**CDF (/ry)**	**LERF (/ry)**
IPE (6/1994)	4.40E-5	N/A[1]
Revision 1 (6/2001)	1.35E-5	5.86E-7
Revision 2 (3/2007)	1.15E-5	9.43E-7

1. The IPE did not provide LERF value since the use of LERF as a risk metric post dates the IPE.

E.3.4.1 Major Differences between the IP3 Revision 1 PSA Model and Original IPE Model

The draft Revision 1 PSA model was peer reviewed in January 2001 and all Level A and B issues and observations from that peer review were addressed in the final version of the Revision 1 PSA model, which was issued in June 2001. Quantification of the final Revision 1 model yielded a measurably lower CDF (point estimate CDF = 1.35E-5/ry) than the original IPE (point estimate CDF = 4.40E-5/ry) [References E.3-1 and E.3-2].

In the Revision 1 PSA model, the contributors in order of dominance were transients (44.14 percent), internal flooding (12.91 percent), LOCA (12.56 percent), SGTRs (10.50 percent), ATWS (9.93 percent), SBO (8.66 percent), and ISLOCA (1.30 percent). In the original IPE, the contributors in order of dominance were transient events (28.9 percent), LOCA (20.1 percent), ATWS (19.6 percent), internal flooding (14.7 per cent), SBO (10.8 percent), SGTR (5.5 percent) and ISLOCAs (less than 1 percent).

Significant changes were made to the IPE model in developing the Revision 1 PSA model. These changes were made to reflect new data, calculations, and modifications to the plant design and procedures. The major model changes impacting CDF and LERF that were incorporated into the IP3 PSA Revision 1 model can be summarized as follows.

Level 1: Core Damage Model

- Updated initiating event database, including all IP3 plant trips that occurred between 1/1/1986 and 12/31/2000.

- Updated component failure data base that reflects failures that occurred between 1/1/1992 and 10/31/1999, and unavailability data base occurred between 1/1/1985 and 10/31/1999, more equipment groups in which common-cause failures may occur and current on-line maintenance practices.

- Revised human reliability analysis to reflect emergency operating procedure changes up to 6/30/2000.

- Revised internal flooding analysis to reflect design and procedure modifications.

- Incorporated Improved Technical Specifications issued in 2001.

- Adopted a more conservative Brookhaven National Laboratory (BNL) RCP seal LOCA model versus Westinghouse model used in original IPE. Revised model reflects installation of qualified high-temperature RCP seals versus "low-temperature" seals in the original IPE analysis.

- Updated offsite power recovery model to reflect loss of offsite power events in NUREG/CR-5496, *Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980-1996*.

- Changed PRA system models and data to reflect various design modifications and procedure changes through October 2000, including those changes associated with recommendations resulting from the original IPE. The major design modifications and procedure changes incorporated in this revision of the model follow.

  - Revision of the maintenance procedure for AFW building exhaust fans, louvers and dampers to improve the availability of AFW building ventilation system.

  - Revision of the emergency procedure for LOCA outside containment, which directs operators to close both SI-899A and SI-747 (or SI-899B and SI-746). This will cope with the potential to create differential pressure in excess of the design capability of SI-1869A or SI-1869B during a LOCA outside containment.

  - Revision of the annunciator response procedure for "Waste Holdup Tank Hi-Lo Level" to mitigate flooding in the PAB. Explicit instructions were added to check whether there is flooding in the PAB on a high-level alarm.

  - Modification of performance test procedures to direct that equipment be restored to the normal position or the position required by the shift manager or control room supervisor. This procedure modification should reduce the likelihood of human performance errors.

- Installation of adequate seismic support for the portion of the fire protection piping deluge valve station located in the control building at 15 ft elevation and installation of a water proof door to the deluge valve station room to reduce overall CDF contribution due to the internal flooding event.

- Installation of temperature detectors to provide a control room alarm upon detection of high ambient temperature on the 15 and 33 ft elevations of the control building.

- Replacement of PORVs to eliminate PORV leakage and allow operation with the block valves open to reduce overall CDF contribution due to ATWS and transient events.

- Reassignment of power supplies to the EDG room exhaust fans eliminating cross-dependencies with other EDGs.

- Modification of 125VDC back-up battery charger 35 to be able to be powered from 480V MCC 36C, 36D, or 36E. This allows flexibility in use of back-up battery charger 35.

- Installation of a diesel-driven station air compressor, which can automatically supply back-up, compressed air to the instrument air system in the event of low system pressure.

- Revision to emergency diesel generator functional test procedures to verify the operational status of each EDG building ventilation system. This procedure modification improves EDG availability since potential failures will be avoided.

• Changed PRA system models and data to reflect WOG peer review recommendations. Specific changes included the following.

  - The small LOCA event tree was modified to include consideration of an RCP seal LOCA due to random mechanical faults during normal plant operation. The RCP seal LOCA initiator frequency (2.5E-3/ry) was taken from NUREG/CR-5750.

  - The plant specific frequencies for the turbine trip (T3) and loss of main feedwater (T2) initiators were recalculated using chronological data that more accurately reflected plant operation. A Bayesian update was performed on the generic frequencies and error factors using IP3 trip data for the time period of 1986-2000. Earlier data, which was not considered representative of current operation, was not included.

  - The plant specific frequency for the loss of offsite power (T1) initiator was recalculated using chronological data that more accurately reflected plant operation. The generic frequency for T1 from NUREG/CR-5750, which is used as input for the Bayesian update, was recalculated minus IP3 data for the time period referenced in NUREG/CR-5750. A Bayesian update was performed on the generic frequency and error factor using critical reactor years for IP3 from 1986-2000.

- A common-cause failure basic event was added to the fault trees for the service water system and CCW initiating events, to model common cause failure of the two normally running pumps, assuming a mission time of one year. Revised initiator frequencies for loss of service water system and loss of CCW were incorporated into the accident sequence quantification.

- Common cause failure events involving valve failure to remain closed were removed from the ISLOCA model. In addition, the exposure time for the initial valve failure was changed to 1 year. Thus, the results of the ISLOCA quantification are in units of per reactor-year. Revised ISLOCA initiator frequencies were incorporated into the accident sequence quantification for CDF and into the containment performance analysis.

- Several common cause beta factors were reviewed and recalculated using the common-cause failure program and reference tables presented in NUREG/CR-5497.

- A number of common cause failure probabilities that were significant contributors to CDF were determined to be unnecessarily conservative and were updated using the Multiple Greek Letter methodology.

- Five separate human error probabilities associated with resetting MCCs were incorporated into a single human error probability to reflect the fact that the actions are all directed as part of the same procedural step.

- A screening process was used in which each master cutset was screened for the occurrence of more than one HRA-related event. Multiple HRA cutsets were then reviewed for potential impact to the overall CDF and a rule file created to apply multiplying factors to the dependent post-accident operator actions.

Level 2 - Containment Performance Model

- Transferred the Level 2 model into the same software used for the Level 1 model (changed from Event Progress Analysis Code-EVNTRE to CAFTA).

- Integrated the Level 1 and Level 2 models in one fault tree model; propagation of Level 1 cutsets to the Level 2 CET was developed.

- Developed a detailed LERF model to ensure that LERF calculations are consistent with the PSA Applications Guide [Reference E.3-15] and NRC requirements for Reg. Guide 1.174.

- Modeled some of IP3 Severe Accident Management Guidelines mitigating strategies for containment flooding and RCS depressurization.

- Revised CET fault tree models to allow credit for AC power recovery following core damage. This ensures that the model does not allow SBO core damage sequences to benefit from AC supported equipment in Level 2 without explicit consideration of AC power recovery.

- As recommended by the WOG peer review, revised assignment of sequences to release categories to include consideration of the predicted cesium-iodide release fraction.

E.3.4.2 Major Differences between the IP3 Revision 2 PSA Model and Revision 1 PSA Model

Quantification of the Revision 2 PSA model [Reference E.3-3] resulted in a slightly lower CDF than Revision 1 (i.e. 1.15E-5/ry for Revision 2 vs. 1.35E-5/yr for Revision 1). Major changes impacting CDF and LERF are summarized as follows.

Level 1: Core Damage Model

- Changed the common-cause failure (CCF) methodology from the modified Beta method to the Alpha method. The Alpha method is a more recent method that has been approved by the NRC and used in the NRC plant Standardized Plant Assessment Risk models.

- Made more extensive use of the generic component failure rates in the component failure database provided in EGG-SSRE-8875.

- Used the RCP seal LOCA model that is documented in WCAP-16141, which was approved for use by the NRC and is also referred to as the WOG2000 RCP Seal LOCA Model. The RCP seal LOCA model used in the previous PSA model was based on the BNL modeling approach. Although the WOG2000 approach is similar to the BNL approach, some differences exist between the two models in terms of assumptions, failure probabilities and timing.

- Revised success criterion for the AFW system to require flow to two (rather than one) of four steam generators for normal (non-ATWS) response. In addition, the normal position of the motor driven AFW pump flow control valves (FCV-406A through D) was changed from open to close.

- Modeled requirement that the operators trip the reactor coolant pumps within a short time after loss of component cooling water event to protect the pumps from a seal LOCA.

- Updated offsite power recovery model based on data contained in NUREG/CR-6890, which provides loss of offsite power data from 1986 to 2004. The offsite power recovery model used in the previous model was based on NUREG/CR-5496 and only included loss of offsite power events through 1996.

- Removed an asymmetry related to the location of the SGTR by assigning an equal probability of the rupture occurring in any one of the four steam generators. The previous model, which assumed that the SGTR occurred within a specific steam generator, impacted the relative importance of the valves involved in isolating the ruptured steam generator.

- Modified success criteria for cooling of the internal recirculation pumps. The previous model allowed credit for providing cooling from either the component cooling water pumps or the auxiliary component cooling water pumps. Since documentation clearly supporting that position was not available, the updated model does not credit those systems as being redundant for this function.

- Removed credit for the gas turbine which is no longer maintained. In addition to the Appendix R diesel, credit was taken in the previous model for an offsite gas turbine (Gas Turbine No. 2) as a method for restoring AC power following a SBO event.

- Included a total loss of service water initiating event in addition to the loss of essential service water and loss of non-essential service water initiating events.

Level 2: Containment Performance Model

- Introduced ten additional PDS to better facilitate the transfer of Level 1 information to the Level 2 containment performance analysis.

- Used the MAAP4 code to update the accident progression analysis. The previous update used the MAAP3 code. A total of fifteen MAAP runs were performed to examine thermal-hydraulic behavior of the RCS and containment, and in-vessel and ex-vessel fission product behavior, following core damage. The previous update used only ten MAAP runs.

- Changed definition of high releases to greater than 10% Cesium-Iodine released, which is consistent with the current industry definition. The previous definition was based on Cesium-Iodine releases greater than 1%.

- Updated accident progression analysis, resulting in changes to some of the CET release category magnitude endstate values (e.g., a number of endstates previously classified as late medium releases were reclassified as late high releases).

E.3.4.3 PSA Model Peer Review

The draft Revision 1 PSA model was peer reviewed in January 2001 using the process adapted by the Westinghouse Owner's Group (WOG) from the process originally developed and used by the Boiling Water Reactor Owners Group and subsequently broadened to be an industry-applicable process, through the Nuclear Energy Institute Risk Applications Task Force. Fact and Observation sheets documented the certification team's insights and their conclusions with regard to potential level of significance. All Level A and B issues and observations from that peer review were addressed in the final version of the Revision 1 PSA model, which was issued in June 2001. Less significant (Level C&D) issues and observations were addressed, where appropriate. Based on the Westinghouse Owner's Group (WOG) peer review, all of the technical elements were graded as sufficient to support applications requiring risk ranking determination; in addition, most of the elements were further graded as sufficient to support risk-informed applications supported by deterministic insights.

For the Revision 1 PSA model, individual work packages (event tree, fault tree, human reliability analysis (HRA), data, etc.), and internal flooding analysis were circulated to each PSA member for independent peer review. The accident sequence packages, system work packages, HRA, and internal flooding analyses were also assigned to the appropriate IP3 plant personnel for review. For example, event trees, system analyses, and fault tree models were forwarded to the applicable plant system engineers and the HRA was assigned to individuals from the plant Operations Training department for review. In addition, the accident sequence packages, system work packages, HRA report, containment performance analysis, fault tree and event tree models, and Level 2 models were peer reviewed by an outside consultant.

The IP3 Revision 2 PSA model was issued in April 2007. The model changes in this update were reviewed for accuracy and consistency by members of the Entergy Nuclear Systems Analysis Group staff not directly involved in their implementation. Additionally, the revised model was subjected to a focused self assessment to demonstrate technical quality in preparation for implementing the Mitigating Systems Performance Indicator program in 2006. Finally, cognizant departments at IP3q—licensing, operations, maintenance, training, planning & scheduling, system engineering and design engineering—were provided with the final results and insights derived from the study for review prior to issuance of the Revision 2 report.

In accordance with plant procedures, potential plant modifications, design change documents, and emergency operating procedure changes are reviewed to determine their impact on the PSA model prior to implementation. A PSA model change request database is maintained to track potential changes and assess their degree of impact of the PSA model. As of December 2006, this database shows no outstanding changes since December 2005 due to modifications or procedure changes that could have a significant impact on the results of the PSA or the SAMA analysis.

E.3.5 MACCS2 Model: Level 3 Analysis

E.3.5.1 Introduction

SAMA evaluation relies on Level 3 PRA results to measure the effects of potential plant modifications. A Level 3 PRA model using the most recent version (version 1.13.1) of MACCS2 [Reference E.3-6] was created for IP3. This model, which requires detailed site-specific meteorological, population, and economic data, estimates the consequences in terms of population dose and offsite economic cost. Risks in terms of population dose risk (PDR) and offsite economic cost risk (OECR) were also estimated in this analysis. Risk is defined as the product of consequence and frequency of an accidental release.

This analysis evaluates a base case to provide best-estimate consequences for postulated internal events. Instead of considering various emergency planning scenarios, the base case uses a conservative assumption of no evacuation.

PDR was estimated by summing over all releases the product of population dose and frequency for each accidental release. Similarly, OECR was estimated by summing over all releases the product of offsite economic cost and frequency for each accidental release. Offsite economic cost includes costs that could be incurred during the emergency response phase and costs that could be incurred through long-term protective actions.

E.3.5.2 Input

The following sections describe the site-specific input parameters used to obtain the offsite dose and economic impacts for cost-benefit analyses.

E.3.5.2.1 Projected Total Population by Spatial Element

The total population within a 50-mile radius of IP3 was estimated for the year 2035, the end of the proposed license renewal period, for each spatial element by combining total resident population projections with transient populations. The 2035 county level resident projections were derived from the New York Statistical Information System from 2000 to 2030, the New Jersey Department of Labor and Workforce Development from 2000 to 2025, the Connecticut State Data Center from 2000 to 2020, and the Pennsylvania State Data Center from 2000 to 2020 using regression analysis [References E.3-16 through E.3-19). The 2035 transient population was assumed to be the 2004 transient to permanent population ratio multiplied by the extrapolated permanent population. The 2004 transient data were obtained from state tourism agencies. Table E.3-12 summarizes the estimated population distribution.

Table E.3-12
Estimated Population Distribution within a 50-mile Radius

Sector	0-10 miles	10-20 miles	20-30 miles	30-40 miles	40-50 miles	50-mile Total
N	12,488	22,955	30,654	39,620	51,057	156,774
NNE	14,952	28,140	39,917	56,226	67,213	206,448
NE	23,377	29,419	53,692	62,559	41,261	210,308
ENE	40,386	74,856	119,073	152,175	176,338	562,828
E	41,290	118,335	156,720	200,581	208,394	725,320
ESE	37,861	121,515	144,267	54,180	34,361	392,184
SE	41,873	111,946	87,735	236,426	379,990	857,970

Table E.3-12
Estimated Population Distribution within a 50-mile Radius
(Continued)

Sector	0-10 miles	10-20 miles	20-30 miles	30-40 miles	40-50 miles	50-mile Total
SSE	12,197	98,326	481,703	1,380,249	1,218,170	3,190,645
S	20,621	135,211	1,164,596	3,732,339	3,164,306	8,217,073
SSW	30,318	202,605	395,389	922,649	1,034,467	2,585,428
SW	30,796	183,372	276,902	197,362	246,076	934,508
WSW	27,723	64,428	209,197	109,102	85,849	496,299
W	16,925	32,026	50,974	61,380	57,384	218,689
WNW	14,036	32,528	54,577	57,977	29,719	188,837
NW	13,421	32,572	54,557	24,046	22,317	146,913
NNW	12,286	31,660	32,569	27,599	34,374	138,488
Total	390,550	1,319,894	3,352,522	7,314,470	6,851,276	19,228,712

E.3.5.2.2 Land Fraction

The land fraction for each spatial element was estimated within the 50 mile radius area. The National Hydrography Dataset was used to estimate the extent of land and surface water coverage [Reference E.3-20].

E.3.5.2.3 Watershed Class

Watershed Index is defined by MACCS2 as areas drained by rivers (Class 1) or large water bodies (Class 2). For IPEC, no spatial elements were treated as large water bodies. Therefore, only one watershed class was assigned for the 50-mile zone surrounding IP3.

E.3.5.2.4 Regional Economic Data

Region Index

Each spatial element was assigned to an economic region, defined in this report as a county. Where a spatial element covers portions of more than one county, it was assigned to that county having the most area within the element.

Regional Economic Data

County level economic data were obtained from the United States Census of Agriculture for 2002 [Reference E.3-21].

VALWF: Value of Farm Wealth

MACCS2 requires an average value of farm wealth (dollars/hectare) for the 50-mile radius area around IPEC. The county-level farmland property value was used as a basis for deriving this value. VALWF is $50,071/hectare.

VALWNF: Value of Non-farm Wealth

MACCS2 also requires an average value of non-farm wealth. The county-level non-farm property value was used as a basis for deriving this value. VALWNF is $163,631/person.

Other economic parameters and their values are shown below. The values were obtained by adjusting the economic data from a past census given as default values in Reference E.3-6 with the consumer price index of 195.3, which is the average value for the year 2005, as appropriate.

Variable	Description	Value
EVACST	Daily cost for a person who has been evacuated ($/person-day)	46.7
POPCST	Population relocation cost ($/person)	8640
RELCST	Daily cost for a person who is relocated ($/person-day)	46.7
CDFRM0	Cost of farm decontamination for the various levels of decontamination ($/hectare)	972 2160
CDNFRM	Cost of non-farm decontamination for the various levels of decontamination ($/person)	5184 13824
DLBCST	Average cost of decontamination labor ($/person-year)	60480
DPRATE	Property depreciation rate (per year)	0.2
DSRATE	Investment rate of return (per year)	0.12

E.3.5.2.5 Agriculture Data

The source of regional crop information is the 2002 Census of Agriculture [Reference E.3-21]. The crops listed for each county within the 50-mile area were summed and mapped into the seven MACCS2 crop categories.

E.3.5.2.6 Meteorological Data

The MACCS2 model requires meteorological data for wind speed, wind direction, atmospheric stability, accumulated precipitation, and atmospheric mixing heights. The required data were obtained from the IPEC meteorological monitoring system and regional National Weather Service stations.

Site Specific Data

IPEC meteorological monitoring system includes both primary and backup systems. The primary meteorological system, which includes a 122-meter instrumented tower located onsite, was the data source for the MACCS2 analysis. Based on a review of annual meteorological data collected at the site between 1995 and 2004, five recent years of data were averaged and used for this study. The five-year data included 43,848 (two leap years) consecutive hourly values of wind speed, wind direction, precipitation, and temperature recorded at the IPEC meteorological tower from January 2000 to December 2004. Missing data were estimated using data substitution methods. These methods include substitution of missing data with valid data from the previous hour and substitution of valid data collected from other elevations on the meteorological tower.

Regional Mixing Height Data

Mixing height is defined as the height of the atmosphere above ground level within which a released contaminant will become mixed (from turbulence) within approximately one hour. Regional mixing heights were calculated using data collected at National Weather Service (NWS) Station No. 72503 in White Plains, NY (approximately 16 miles southeast of IP3) and NWS Station No. 54775 in Albany, NY (approximately 80 miles north of IP3). These two weather stations were the closest NWS sources of data for local and upper air conditions. Staff meteorologists at the National Climatic Data Center selected these two stations for data used to calculate seasonal mixing height values for the IP3 area.

E.3.5.2.7 Emergency Response Assumptions

A detailed analysis of evacuation scenarios in emergency planning zone (EPZ) were addressed in the IP3 evacuation travel time estimate study [Reference E.3-22]. The study was conducted in 2004 and provides an analysis of the range and variation of public reaction to the evacuation notification process. Evacuation, which is considered an effective measure for mitigating accident consequences, would reduce radiation dose received by population within the EPZ. The primary parameters affecting evacuation consequences are evacuation speed and time elapsed prior to the start of evacuation. Either a lower speed of evacuation or a delayed evacuation would increase the received radiation dose. In turn, should no evacuation occur, the dose would be higher. For this study, a "no evacuation scenario" was assumed to conservatively estimate the population dose.

E.3.5.2.8 Core Inventory

The estimated IP3 core inventory (Table E.3-13) used in the MACCS2 input is based on current core configuration and a power level of 3216 MW(t).

Table E.3-13
IP3 Core Inventory (Becquerels)[1]

Nuclide	Inventory	Nuclide	Inventory
Co-58	3.04E+16	Te-131m	4.64E+17
Co-60	2.32E+16	Te-132	4.54E+18
Kr-85	3.87E+16	I-131	3.18E+18
Kr-85m	8.52E+17	I-132	4.64E+18
Kr-87	1.64E+18	I-133	6.56E+18
Kr-88	2.30E+18	I-134	7.19E+18
Rb-86	8.24E+15	I-135	6.14E+18
Sr-89	3.09E+18	Xe-133	6.25E+18
Sr-90	3.07E+17	Xe-135	1.67E+18
Sr-91	3.87E+18	Cs-134	7.16E+17
Sr-92	4.19E+18	Cs-136	2.08E+17
Y-90	3.20E+17	Cs-137	4.15E+17
Y-91	3.98E+18	Ba-139	5.86E+18
Y-92	4.22E+18	Ba-140	5.58E+18
Y-93	4.85E+18	La-140	5.76E+18
Zr-95	5.38E+18	La-141	5.34E+18
Zr-97	5.41E+18	La-142	5.17E+18
Nb-95	5.45E+18	Ce-141	5.31E+18
Mo-99	6.11E+18	Ce-143	4.99E+18
Tc-99m	5.34E+18	Ce-144	4.19E+18
Ru-103	4.85E+18	Pr-143	4.78E+18

Table E.3-13
IP3 Core Inventory (Becquerels)[1] (Continued)

Nuclide	Inventory	Nuclide	Inventory
Ru-105	3.34E+18	Nd-147	2.12E+18
Ru-106	1.69E+18	Np-239	6.53E+19
Rh-105	3.08E+18	Pu-238	1.43E+16
Sb-127	3.45E+17	Pu-239	1.22E+15
Sb-129	1.04E+18	Pu-240	1.82E+15
Te-127	3.43E+17	Pu-241	4.08E+17
Te-127m	4.47E+16	Am-241	5.03E+14
Te-129	1.02E+18	Cm-242	1.21E+17
Te-129m	1.49E+17	Cm-244	1.29E+16

1. Derived from Reference E.3-23 for a power level of 3216 MWth except for Co-58 and Co-60, which were power-scaled from the reference inventory given in Reference E.3-6.

E.3.5.2.9 Source Terms

Only eight release categories given in Table E.3-9, corresponding to internal event sequences, were part of the MACCS2 input. The Early Low-Low category has zero release frequency and is not considered. Section E.3.2.2.7 provides details of the source terms for postulated internal events. A linear release rate was assumed between the time the release started and the time the release ended.

E.3.5.3 Results

Risk estimates for the base case were analyzed with MACCS2. The base case assumes no evacuation. Table E.3-14 shows estimated base case mean risk values for each release mode. The estimated mean values of PDR and offsite OECR for IP3 are 24.5 person-rem/yr and $52,800/yr, respectively.

Table E.3-14
Base Case Mean PDR and OECR Values

Release Mode	Frequency (/yr)	Population Dose (person-sv)[1]	Offsite Economic Cost ($)	Population Dose Risk (PDR) (person-rem/yr)	Offsite Economic Cost Risk (OECR) ($/yr)
NCF	6.30E-06	3.85E+01	1.54E+05	2.42E-02[2]	9.69E-01
EARLY HIGH	9.43E-07	1.31E+05	2.98E+10	1.24E+01	2.81E+04
EARLY MEDIUM	1.24E-06	5.13E+04	1.14E+10	6.35E+00	1.41E+04
EARLY LOW	1.46E-07	1.37E+04	2.15E+09	1.99E-01	3.13E+02
LATE HIGH	4.23E-07	4.24E+04	1.04E+10	1.79E+00	4.40E+03
LATE MEDIUM	2.01E-06	1.78E+04	2.83E+09	3.57E+00	5.68E+03
LATE LOW	3.75E-07	5.36E+03	5.24E+08	2.01E-01	1.96E+02
LATE LOWLOW	5.66E-08	4.63E+03	4.60E+08	2.62E-02	2.60E+01
			Totals	**2.45E+01**	**5.28E+04**

1. 1 sv = 100 rem
2. 2.42E-02 (person-rem/yr) = 6.30E-06 (/yr) x 3.85E+01 (person-sv) x 100 (rem/sv)

E.3.6 References

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E.3-2 IP3-RPT-MULT-01539, "Indian Point 3 Nuclear Power Plant Individual Plant Examination Revision 1, June 2001.

E.3-3 IP-RPT-06-00071 "Indian Point Unit 3 Nuclear Power Plant Probabilistic Safety Assessment, Revision 2," April 2007.

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E.3-5 Kaiser, "The Implications of Reduced Source Terms for Ex-Plant Consequence Modeling," Executive Conference on the Ramifications of the Source Term (Charleston, SC), March 12, 1985.

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E.3-8 IP3-RPT-UNSPEC-02182, "Indian Point Three Nuclear Power Plant Individual Plant Examination for External Events," September 1997, Revision 0.

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E.3-22 KLD Associates, Inc. October 2004. Revision 2. Indian Point Energy Center Development of Evacuation Time Estimates. Report KLD TR 369. 422 pp. KLD Associates, Commack, NY.

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ATTACHMENT E.4

EVALUATION OF IP3 SAMA CANDIDATES

E.4 EVALUATION OF IP3 SAMA CANDIDATES

This section describes the generation of the initial list of potential SAMA candidates, screening methods, and the analysis of the remaining SAMA candidates.

E.4.1 SAMA List Compilation

A list of SAMA candidates was developed by reviewing industry documents and considering plant-specific enhancements not identified in published industry documents. Since IP3 is a conventional pressurized water reactor, considerable attention was paid to the SAMA candidates from SAMA analyses for other pressurized water reactor plants. Industry documents reviewed include the following.

- Calvert Cliffs Nuclear Power Plant SAMA Analysis [Reference E.4-1]
- H.B. Robinson Steam Electric Plant Unit No.2 SAMA Analysis [Reference E.4-2]
- Virgil. C. Summer Nuclear Station SAMA Analysis [Reference E.4-3]
- Arkansas Nuclear One Unit 2 SAMA Evaluation [Reference E.4-4]
- Donald C. Cook Nuclear Plant SAMA Analysis [Reference E.4-5]
- Millstone Units 2 and 3 SAMA Analysis [Reference E.4-6]
- Joseph M. Farley Nuclear Plant SAMA Analysis [Reference E.4-7]
- Point Beach Nuclear Plant Units 1 and 2 SAMA Analysis [Reference E.4-8]
- Palisades Nuclear Plant SAMA Analysis [Reference E.4-28]

The above documents represent a compilation of most SAMA candidates developed from the industry documents. These sources of other industry documents include the following.

- Quad Cities SAMA Analysis [Reference E.4-9]
- General Electric ABWR severe accident mitigation design alternative (SAMDA) Analysis [Reference E.4-10]
- Limerick SAMDA cost estimate report [Reference E.4-11]
- NUREG-1437 description of Limerick SAMDA [Reference E.4-12]
- NUREG-1437 description of Comanche Peak SAMDA [Reference E.4-13]
- Tennessee Valley Authority (TVA) response to NRC's RAI on the Watts Bar SAMDA submittal [Reference E.4-14]
- TVA response to NRC's RAI on the Watts Bar Generic Letter 88-20 IPE for Severe Accident Vulnerabilities [Reference E.4-15]
- Westinghouse AP600 SAMDA [Reference E.4-16]
- NUREG-1462, Final safety evaluation report related to the certification of Combustion Engineering System 80+ design [Reference E.4-17]
- NUREG-0498, Final Environmental Statement related to the Operation of Watts Bar Nuclear Plant Units 1 and 2, Supplement 1, Section 7 [Reference E.4-18]
- NUREG-1560, Volume 2, NRC Perspectives on the IPE Program [Reference E.4-19]
- NUREG/CR-5474, Assessment of Candidate Accident Management Strategies [Reference E.4-20]

In addition to SAMA candidates from review of industry documents, SAMA candidates were obtained from plant-specific sources, such as the IP3 IPE and updates [References E.4-21, E.4-22 and E.4-23] and IPEEE [Reference E.4-24]. In the original IPE and IPEEE, several enhancements related to severe accident insights were recommended and implemented. These enhancements are included in the comprehensive list of Phase I SAMA candidates. Table E.4-1 lists the IPE, PSA model update, and IPEEE Phase I SAMA candidates and indicates which have been implemented, which have been incorporated in the model used for the SAMA analysis, and which have been retained for further evaluation in Phase II of the SAMA analysis. The current PSA was also used to identify plant-specific modifications for inclusion in the comprehensive list of SAMA candidates. The risk significant terms from the current PSA model were reviewed for similar failure modes and effects that could be addressed through a potential enhancement to the plant. The correlation between SAMAs and the risk significant terms are listed in Table E.3-2 and Table E.3-5.

The comprehensive list contained a total of 237 Phase I SAMA candidates and is available in onsite documentation.

E.4.2 <u>Qualitative Screening of SAMA Candidates (Phase I)</u>

The purpose of the preliminary SAMA screening was to eliminate from further consideration enhancements that were not viable for implementation at IP3. Potential SAMA candidates were screened out if they modified features not applicable to IP3, if they had already been implemented at IP3, or if they were similar in nature and could be combined with another SAMA candidate to develop a more comprehensive or plant-specific SAMA candidate. During this process, 55 of the Phase I SAMA candidates were screened out because they were not applicable to IP3, 6 of the Phase I SAMA candidates were screened out because they were similar in nature and could be combined with another SAMA candidate, and 114 of the Phase I SAMA candidates were screened out because they had already been implemented at IP3, leaving 62 SAMA candidates for further analysis. The final screening process involved identifying and eliminating those items whose implementation cost would exceed their benefit as described below. Table E.4-2 provides a description of each of the 62 Phase II SAMA candidates. As described in Section 4.21.5.4, the "baseline benefit" values in this table represent the total SAMA benefits for both internal and external events.

E.4.3 <u>Final Screening and Cost Benefit Evaluation of SAMA Candidates (Phase II)</u>

A cost/benefit analysis was performed on each of the remaining SAMA candidates. If the implementation cost of a SAMA candidate was determined to be greater than the potential benefit (i.e. there was a negative net value) the SAMA candidate was considered not to be cost beneficial and was not retained as a potential enhancement.

The expected cost of implementation of each SAMA was established from existing estimates of similar modifications. Most of the cost estimates were developed from similar modifications considered in previously performed SAMA. In particular, these cost-estimates were derived from the following sources.

- Arkansas Nuclear One Unit 2 SAMA Analysis [Reference E.4-4]
- Calvert Cliffs SAMA Analysis [Reference E.4-1]
- Donald C. Cook SAMA Analysis [Reference E.4-5]
- Fort Calhoun Unit 1 SAMA Analysis [Reference E.4-25]
- Joseph M. Farley SAMA Analysis [Reference E.4-7]
- McGuire SAMA Analysis [Reference E.4-26]

The cost estimates did not include the cost of replacement power during extended outages required to implement the modifications, nor did they include contingency costs associated with unforeseen implementation obstacles. Estimates based on modifications that were implemented or estimated in the past were presented in terms of dollar values at the time of implementation (or estimation), and were not adjusted to present-day dollars. Therefore, the cost estimates were conservative.

The benefit of implementing a SAMA candidate was estimated in terms of averted consequences. The benefit was estimated by calculating the arithmetic difference between the total estimated costs associated with the four impact areas for the baseline plant design and the total estimated impact area costs for the enhanced plant design (following implementation of the SAMA candidate).

Values for avoided public and occupational health risk were converted to a monetary equivalent (dollars) via application of the NUREG/BR-0184 [Reference E.4-27] conversion factor of $2,000 per person rem and discounted to present value. Values for avoided offsite economic costs were also discounted to present value.

As this analysis focuses on establishing the economic viability of potential plant enhancement when compared to attainable benefit, detailed cost estimates often were not required to make informed decisions regarding the economic viability of a particular modification. Several of the SAMA candidates were clearly in excess of the attainable benefit estimated from a particular analysis case.

For less clear cases, engineering judgment on the cost associated with procedural changes, engineering analysis, testing, training, and hardware modification was applied to determine if a more detailed cost estimate was necessary to formulate a conclusion regarding the economic viability of a particular SAMA. Based on a review of previous submittals' SAMA evaluations and an evaluation of expected implementation costs at IP3, the following estimated costs for each potential element of the proposed SAMA implementation were used.

Type of Change	**Estimated Cost Range**
Procedural only	$25K-$50K
Procedural change with engineering required	$50K-$200K
Procedural change with engineering and testing/training required	$200K-$300K

Type of Change	Estimated Cost Range
Hardware modification	\$100K to >\$1000K

In most cases, more detailed cost estimates were not required, particularly if the SAMA called for the implementation of a hardware modification. Nonetheless, the cost of each unscreened SAMA candidate was conceptually estimated to the point where conclusions regarding the economic viability of the proposed modification could be adequately gauged. The cost benefit comparison and disposition of each of the 62 Phase II SAMA candidates is presented in Table E.4-2.

Bounding evaluations (or analysis cases) were performed to address specific SAMA candidates or groups of similar SAMA candidates. These analysis cases overestimated the benefit and thus were conservative calculations. For example, one SAMA candidate suggested installing a digital feedwater upgrade system. The bounding calculation estimated the benefit of this improvement by total elimination of risk due to loss of feedwater events (see analysis of Phase II SAMA 039 in Table E.4-2). This calculation obviously overestimated the benefit, but if the inflated benefit indicated that the SAMA candidate was not cost beneficial, then the purpose of the analysis was satisfied.

A description of the analysis cases used in the evaluation follows.

Diesel Powered RCP Seal Injection

This analysis case was used to evaluate the change in plant risk from providing an independent, diesel powered RCP seal cooling system. The plant modification involves installation of a two-inch pipe inside containment and the PAB, manual isolation valves, control valves, instrumentation to monitor flow, self-contained diesel generator outside the PAB, pump, instrumentation cables, four orifices, power cable to the pump, two filters, water source piping and valves, and containment penetration piping and instrumentation. It also requires revision of standard operating and emergency operating procedures; calculations for piping and support dead weight, electrical load, and instrumentation setpoints; additional procedures; and training. The RCP seal cooling enhancements would add redundancy to RCP seal cooling, reducing CDF from loss of component cooling or service water or from a SBO event. A bounding analysis was performed by setting all consequential RCP seal LOCAs from all plant initiators to zero in the Level 1 PDS model, which resulted in a baseline benefit of approximately \$135,611. This analysis case was used to model the benefit of Phase II SAMA 001.

Non-Diesel Powered RCP Seal Injection

This analysis case was used to evaluate the change in plant risk from providing an independent RCP seal cooling system without dedicated diesel power backup. RCP seal cooling enhancements would add redundancy to RCP seal cooling, reducing CDF from loss of component cooling or service water or from a SBO event. A bounding analysis was performed by setting all consequential RCP seal LOCAs from all plant initiators to zero in the level 1 PDS model, which resulted in a baseline benefit of approximately $100,223. This analysis case was used to model the benefit of Phase II SAMA 002.

Additional CCW Pump

This analysis case was used to evaluate the change in plant risk from installing an additional CCW pump. An additional CCW pump reduces the probability of loss of component cooling leading to a RCP seal LOCA. A bounding analysis was performed by setting common cause failures of CCW pumps to zero in the Level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMA 003.

RHR Heat Exchangers

This analysis case was used to evaluate the change in plant risk by improving the ability to cool the RHR heat exchangers by implementing procedure and hardware modifications to allow manual alignment of the fire protection system. A bounding analysis was performed by setting loss of CCW to the RHR heat exchangers to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $35,517. This analysis case was used to model the benefit of Phase II SAMA 004.

Filtered Containment Vent

This analysis case was used to evaluate the change in plant risk from installing a filtered containment vent to provide fission product scrubbing. A bounding analysis was performed by setting late containment overpressurization failure to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately $504,995. This analysis case was used to model the benefit of Phase II SAMA 005.

Molten Core Debris Removal

This analysis case was used to estimate the change in plant risk from providing a molten core debris cooling mechanism. The plant modification for a reactor cavity flooding system involves use of fire water as a supply, a run of 500 feet of 8-inch pipe to a 1000 gpm pump (similar to containment spray pump) and a run of 8-inch pipe from the pump spare piping penetration. A 1-inch mini-flow test line and instrumentation would be required for periodic testing. In addition, calculations would be required for pipe support, pump capacity, electric cable, electrical loading, flow, and instrumentation. Additional procedures and training for alignment would also be required. A bounding analysis was performed by setting containment failure due to core-concrete interaction to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately $1,378,340. This analysis case was used to model the benefit of Phase II SAMAs 006, 007, and 008.

Inert Containment

This analysis case was used to estimate the change in plant risk from providing a means to inert containment to prevent combustion of hydrogen and carbon monoxide gases. A bounding analysis was performed by setting containment failures due to hydrogen burns to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately $552,524. This analysis case was used to model the benefit of Phase II SAMA 009.

Containment Sprays

This analysis case was used to evaluate the change in plant risk from installing additional containment spray capability to provide containment pressure control. A bounding analysis was performed by setting the events for loss of containment spray to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMAs 010, 011, and 014.

Base Mat Melt-Through

This analysis case was used to evaluate the change in plant risk from increasing the depth of the concrete base mat to ensure base mat melt-through does not occur. A bounding analysis was performed by setting containment failure due to base mat melt-through to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately $297,056. This analysis case was used to model the benefit of Phase II SAMA 012.

Strengthen Containment

This analysis case was used to evaluate the change in plant risk from strengthening containment by constructed a building connected to primary containment that is maintained at a vacuum to provide a method to depressurize containment and reduce fission product release. The proposed plant modification involves construction of a building structurally strong enough to sustain an approximately 10 psi pressure differential. Vacuum pump, piping (600 feet), electrical equipment, instrumentation, and containment penetrations would be required.   A bounding analysis was performed by setting all energetic containment failure modes (DCH, steam explosions, late over-pressurization) to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately $1,271,400. This analysis case was used to model the benefit of Phase II SAMA 013.

Containment Liner Protection

This analysis case was used to evaluate the change in plant risk from constructing a barrier that provides containment liner protection from ejected core debris at high RCS pressure. The proposed plant modification involves installation of a 50 foot diameter, 70 foot high barrier made of stainless steel. A bounding analysis was performed by setting the probability of HPME and subsequent DCH at high RCS pressure to zero in the level 2 PSA model, which resulted in a baseline benefit of approximately $255,468. This analysis case was used to model the benefit of Phase II SAMA 015.

Steam Generator Heat Removal

This analysis case was used to evaluate the change in plant risk from installing a highly reliable steam generator shell-side heat removal system that relies on natural circulation and stored water sources. The proposed plant modification involves installation of two 8-inch penetrations into each steam generator, eight lengths of 8-inch pipe and supports inside containment, eight containment penetrations, piping and supports outside of containment, a water storage tank (about 300,000 gallons), tank heater, and instrumentation. It would also require hydro testing, procedure revisions and training. This SAMA would provide an additional means to scrub fission product releases. A bounding analysis was performed by setting SGTR with loss of secondary-side cooling events to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $356,079. This analysis case was used to model the benefit of Phase II SAMA 016.

Secondary Side Pressure Capacity

This analysis case was used to evaluate the change in plant risk from increasing the secondary side pressure capacity to lower the occurrence of an unisolated SGTR. A bounding analysis was performed by eliminating failure to isolate the ruptured steam generator during a SGTR to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $2,909,856. This analysis case was used to model the benefit of Phase II SAMA 017.

SGTR Fission Product Scrubbing

This analysis case was used to evaluate the change in plant risk from routing the discharge from the main steam safety valves through a structure where water spray would condense the steam and scrub the fission products inventory. The proposed plant medication involves installation of four tanks (50 feet long with 20 spray nozzles) and 400 feet of city water piping and supports. Procedure revisions and training would also be required. A bounding analysis was performed by reducing SGTR accident progression source terms by a factor of 2, which resulted in a baseline benefit of approximately $665,406. This analysis case was used to model the benefit of Phase II SAMA 018.

ISLOCA Mitigation

This analysis case was used to evaluate the change in plant risk from installing additional pressure or leak monitoring instrumentation between the pressure isolation valves in ISLOCA pathways or submerging potential ISLOCA break points in water. A bounding analysis was performed by setting all ISLOCA initiators to zero in the level 1 PSA model which resulted in a baseline benefit of approximately $457,208. This analysis case was used to model the benefit of Phase II SAMAs 019 and 022.

ISLOCA Valves

This analysis case was used to evaluate the change in plant risk from reducing the probability of an ISLOCA by increasing the frequency of valve leak testing or adding redundant and diverse limit switches to each containment isolation valve. The increased valve leak testing involves testing of 34 safety-related valves in containment. To allow testing of valves located inside containment during power operation, installation of a test connection for each valve with piping outside of containment and double containment isolation valves would be required. In addition, procedure revisions and training would be required. A bounding analysis was performed by reducing the ISLOCA initiator 50 percent in the level 1 PSA model, which resulted in a baseline benefit of approximately $219,692. This analysis case was used to model the benefit of Phase II SAMAs 020 and 021.

MSIV Design

This analysis case was used to evaluate the change in plant risk from improving MSIV design to decrease the likelihood of containment bypass scenarios. A bounding analysis was performed by setting MSIV failures to isolate a faulted or ruptured steam generator to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMA 23.

DC Power/ AFW System Changes

This analysis case was used to evaluate the change in plant risk from plant modifications that would increase the availability of Class 1E DC power (i.e., increasing battery capacity, using fuel cells, improving DC bus load shedding, or extending auxiliary feed pump operation after battery depletion). It was assumed that battery life could be significantly extended from the existing battery capacity. The proposed plant modification for extending the AFW steam-driven pump operation after battery depletion involves purchasing, staging and maintaining a portable generator with fuel supply, control station, conduit and cabling. This enhancement would extend AFW steam-driven pump operability and allow more time for AC power recovery.

This analysis case was also used to evaluate the change in plant risk from plant modifications to install pneumatic controls and indication for the turbine-driven AFW pump to reduce the CDF contribution from SBO events. The proposed plant modification for this SAMA involves installation of ten local instruments since the existing system includes some electrical and pneumatic controls. Procedure revisions and training would also be required.

A bounding analysis was performed by changing the time available to recover offsite power before local operation of the AFW steam-driven pump is required from 2 hours to 24 hours during SBO scenarios in the level 1 PSA model. This resulted in a baseline benefit of approximately $35,259. This analysis case was used to model the benefit of Phase II SAMAs 024, 025, 026, 042 and 056.

AC Power Cross-Tie with Indian Point Unit 2 (IP2)

This analysis case was used to evaluate the change in plant risk from a plant modification to create an AC power cross-tie with IP2 to improve AC power reliability. The proposed plant modification involves installation of two breakers and 1500 feet of cable, conduit and supports from the 480 VAC switchgears. Procedure development and training would also be required. A bounding analysis was performed by setting loss of the Appendix R diesel to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $58,765. This analysis case was used to model the benefit of Phase II SAMA 027.

EDG Alternate Engine Cooling

This analysis case was used to evaluate the change in plant risk from providing a redundant and diverse source of engine cooling for the EDGs, which would contribute to enhanced diesel reliability. A bounding analysis was performed by setting loss of the essential service water supply for diesel cooling to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $11,753. This analysis case was used to model the benefit of Phase II SAMAs 028 and 029.

Alternate Battery Charger Capability

This analysis case was used to evaluate the change in plant risk from plant modifications to provide alternate battery charging capabilityby installing a portable diesel-driven battery charger. The proposed plant modification involves purchasing, installing and maintaining a diesel-driven generator to charge the 125VDC batteries. Safety-related quick disconnects would be used to charge the selected battery. The diesel generator would be installed in a weather enclosure outside the turbine or control building, requiring fire barrier penetration sealing. The location would be as close as possible to the batteries to decrease power loss along the cable. Calculation of cable size would have to be performed. In addition, procedure development and training would be required. A bounding analysis was performed by changing the time available to recover offsite power before local operation of AFW is required from 2 hours to 24 hours during SBO scenarios and reducing internal switchgear room floods 5 percent to account for local operation of the turbine-driven AFW pump. This resulted in a baseline benefit of approximately $509,643. This analysis case was used to model the benefit of Phase II SAMA 030.

Improve 118VAC System

This analysis case was used to evaluate the change in plant risk from plant modifications to convert under-voltage AFW and reactor protective system actuation signals from 2-out-of-4 to 3-out-of-4 logic. This would reduce the risk associated with inverter failure and would improve the availability of the 118VAC vital bus. A bounding analysis was performed by setting common cause failure of the 118VAC transformers to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $23,764. This analysis case was used to model the benefit of Phase II SAMA 031.

Low Pressure Injection System

This analysis case was used to evaluate the change in plant risk from plant modifications that would increase the availability of alternate low pressure injection (i.e., additional diesel-driven low pressure vessel makeup or modification of the diesel-driven fire pump). Use of the diesel-driven fire pump for low pressure injection requires installation of piping, valves and supports. Procedure development and training would also be required. A bounding analysis was performed by eliminating failure of the RHR system in the level 1 PSA model, which resulted in a baseline benefit of approximately $5,941. This analysis case was used to model the benefit of Phase II SAMAs 032 and 035.

High Pressure Injection System

This analysis case was used to evaluate the change in plant risk from plant modifications that would increase the availability of high pressure injection (i.e., installing a diesel-driven high pressure injection system or replacing two of the three motor-driven SI pumps with diesel-powered pumps). A bounding analysis was performed by setting failure of the SI system to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $35,517. This analysis case was used to model the benefit of Phase II SAMAs 033 and 037.

Automatic Recirculation Cooling Swap-Over

This analysis case was used to evaluate the change in plant risk from installing an automatic swap-over to recirculation cooling upon RWST depletion to enhance the reliability of ECCS suction. A bounding analysis was performed by setting failure to align recirculation cooling (internal and external) to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $340,435. This analysis case was used to model the benefit of Phase II SAMA 034.

Conserve RWST Water Inventory

This analysis case was used to evaluate the change in plant risk from extending reactor water storage tank capability by throttling low pressure injection flow earlier in medium or large-break LOCAs. A bounding analysis was performed by setting failure to align recirculation cooling (internal and external) in large and medium LOCAs to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $11,753. This analysis case was used to model the benefit of Phase II SAMA 036.

Enhance RCS Depressurization

This analysis case was used to evaluate the change in plant risk from enhancing RCS depressurization to allow successful low pressure ECCS injection following a small LOCA and high pressure SI failure. A bounding analysis was performed by setting common cause failure of the steam generator atmospheric dump valves (ADVs) to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $65,223. This analysis case was used to model the benefit of Phase II SAMA 038.

Main Feedwater System Upgrade

This analysis case was used to evaluate the change in plant risk from installing a digital feedwater upgrade to reduce the probability of loss of main feedwater following a plant trip or to install a motor-driven feedwater pump to enhance the availability of feed water injection subsequent to MSIV closure. A bounding analysis was performed by setting the loss of main feedwater initiator to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $206,128. This analysis case was used to model the benefit of Phase II SAMAs 039 and 041.

Steam Generator Atmospheric Steam Dump Valve Enhancement

This analysis case was used to evaluate the change in plant risk in automating the backup nitrogen supply to the steam generator atmospheric steam dump valve (ADV). This would eliminate the need for local manual action to align nitrogen bottles for control air during a LOOP. A bounding analysis was performed by setting the manual local action to align nitrogen supply for control air supply to the steam generator ADV to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $65,223. This analysis case was used to model the benefit of Phase II SAMA 040.

Alternate Water Sources to Steam Generators

This analysis case was used to evaluate the change in plant risk from providing emergency connections to use the fire water system as backup for steam generator inventory. The proposed modification involves installation of 500 feet of 6-inch pipe from the fire pump house to a new electric 800 gpm pump. The modification would also require heat tracing, valves, supports, breakers and cabling, procedure development and training. A bounding analysis was performed by setting failure of the turbine-driven AFW pump and failure to restore AC power given successful AFW operation during SBO to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $183,140. This analysis case was used to model the benefit of Phase II SAMA 043.

Install Large Pressurizer PORVs

This analysis case was used to evaluate the change in plant risk from installing larger capacity power operated relief valves to allow successful feed and bleed cooling with one valve open. A bounding analysis was performed by modifying the number of PORVs required for RCS feed and bleed from 2-of-2 to 1-of-2 and to account for the additional time to aligned bleed and feed, the operator action for bleed and feed is reduced by a factor of 5 in the level 1 PSA model, which resulted in a baseline benefit of approximately $337,997. This analysis case was used to model the benefit of Phase II SAMA 044.

Independent Boron Injection System

This analysis case was used to evaluate the change in plant risk from installing an independent boron injection system to provide a redundant means to shut down the reactor during ATWS. A bounding analysis was performed by setting common cause failure of the boric acid transfer pumps to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMAs 045.

ATWS Overpressure Protection

This analysis case was used to evaluate the change in plant risk from installing a system of relief valves in the RCS to prevent equipment damage from a pressure spike during an ATWS. This enhancement would improve equipment availability after an ATWS. The proposed modification involves installation of additional safety valves discharge lines to the pressurizer relief tank, acoustic monitoring, and RCS hydro capability. Procedure development and training would also be required. A bounding analysis was performed by setting the CDF contribution from RCS overpressurization during an ATWS to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $176,682. This analysis case was used to model the benefit of Phase II SAMA 046.

Control Room ATWS Mitigation

This analysis case was used to evaluate the change in plant risk from installing motor generator set trip breakers in the control room (SAMA 47) or providing the capability to remove power from the bus powering the control rods (SAMA 48). For SAMA 47, the proposed plant modification involves installation of two additional breakers, 300 feet of cable, conduit and supports. This modification also requires two penetrations of the control room boundary and resealing, procedure development and training. For SAMA 48, procedure changes and training would be required. These enhancements would reduce the CDF due to ATWS. A bounding analysis was performed by setting failure to trip the control rod motor generator sets to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $23,506. This analysis case was used to model the benefit of Phase II SAMAs 047 and 048.

Large Break LOCA

This analysis case was used to evaluate the change in plant risk from installing a digital large break LOCA protection system. The proposed plant modification involves installation of nine analog to digital converters, digital logic racks, and input into the emergency safeguard system logic relay racks. Procedure modifications and training would also be required. A bounding analysis was performed by setting the large break LOCA initiator to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMA 049.

Main Steam Line Break inside Containment

This analysis case was used to evaluate the change in plant risk from installing secondary side guard pipes up to the MSIVs. This enhancement would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. This SAMA would also guard against or prevent consequential multiple SGTRs following a main steam line break event. A bounding analysis was performed by setting the main steam line break initiators (inside and outside containment) to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $611,289. This analysis case was used to model the benefit of Phase II SAMA 050.

Main Feedwater Secondary-Side Cooling

This analysis case was used to evaluate the change in plant risk from aligning the main feedwater for secondary heat removal to reduce the CDF contribution from transients and subsequent loss of AFW secondary-side cooling. A bounding analysis was performed by setting failure of condensate secondary-side cooling to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $11,753. This analysis case was used to model the benefit of Phase II SAMA 051.

AFW System Alternate Suction Supply

This analysis case was used to evaluate the change in plant risk from opening the city water supply valve for alternative AFW pump suction. This SAMA would enhance the availability of AFW. A bounding analysis was performed by setting loss of normal suction path to the AFW system to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $65,223. This analysis case was used to model the benefit of Phase II SAMA 052.

Plant Hydrogen Control

This analysis case was used to evaluate the change in plant risk from plant modifications to install an excess flow valve to reduce the risk associated with hydrogen explosions inside the turbine building or PAB. The proposed plant modification involves installation of a non-electric excess flow valve. Procedure revisions and training would also be required. A bounding analysis was performed by eliminating hydrogen ruptures inside the turbine building, which resulted in a baseline benefit of approximately $142,328. This analysis case was used to model the benefit of Phase II SAMA 053.

Pressurizer PORV DC Power

This analysis case was used to evaluate the change in plant risk from plant modifications to provide a backup source of DC power for the PORVs. This enhancement would reduce the CDF contribution from loss of secondary heat sink and enhance feed and bleed availability. The proposed plant modification involves installation of an additional battery, inverter, charger and two transfer switches. Procedure revisions and training would also be required. A bounding analysis was performed by setting failure of DC power to the PORVs to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMA 054.

Appendix R Power to SI or RHR Pump

This analysis case was used to evaluate the change in plant risk from plant modifications for a hard-wired connection to one SI or RHR pump from the Appendix R diesel (MCC-312A) power supply. This enhancement would reduce the CDF contribution from internal and external events that cause loss of power from the 480V vital buses. The proposed plant modification involves installation of 500 feet of cable and conduit, a breaker and transfer switches. Procedure revisions and training would also be required. A bounding analysis was performed by setting failure to align MCC-312A to power the charging pump to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $11,274,884. This analysis case was used to model the benefit of Phase II SAMA 055.

CCW Heat Exchanger Alternate Cooling Supply

This analysis case was used to evaluate the change in plant risk from providing a backup cooling water source for the CCW heat exchangers. This enhancement would reduce the CDF contribution from loss of non-essential service water events. The proposed plant change involves use of backup service water pumps to cool the CCW heat exchangers. Piping and valves exists to implement this change, however, additional analysis would be required to ensure adequate cooling flow (electrical load and service water flow). In addition, procedure changes and training would be required. A bounding analysis was performed by setting the loss of non-essential service water initiator to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $35,259. This analysis case was used to model the benefit of Phase II SAMA 057.

Backup DC Power Supply

This analysis case was used to evaluate the change in plant risk from providing an automatic backup DC power supply. This enhancement reduces the CDF associated with loss of a DC bus. The proposed plant modification involves installation of four transfer switches and instrumentation. Procedure revisions and training would also be required. A bounding analysis was performed by setting the loss of DC Bus 31 and Bus 32 initiators to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $76,459. This analysis case was used to model the benefit of Phase II SAMA 058.

Charging Pump Alternate Cooling

This analysis case was used to evaluate the change in plant risk from plant modifications to allow the primary water system to cool the charging pumps. This enhancement would reduce the effect of loss of component cooling by providing an alternate means to cool the charging pumps and preserve seal injection after loss of component cooling. The proposed plant modification involves installation of two manual valves and 100 feet of piping per charging pump. Procedure revisions and training would also be required. A bounding analysis was performed by setting failure to align city water to the charging pumps to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMA 059.

Recirculation Pump Motor Alternate Cooling

This analysis case was used to evaluate the change in plant risk from providing an independent source of cooling for the recirculation pump motors to reduce CDF associated due to loss of CCW events. The proposed plant modification involves connecting city water or primary water supply to the piping associated with the auxiliary component cooling pumps, including isolation valves and supports (~300 feet of piping). A discharge drain line, procedure development and training would also be required. A bounding analysis was performed by setting loss of CCW to the recirculation pumps to zero in the level 1 PSA model, which resulted in no benefit. This analysis case was used to model the benefit of Phase II SAMA 060.

Upgrade Alternate Safe Shutdown System (ASSS) for RCP Seal Cooling

This analysis case was used to evaluate the change in plant risk from upgrading the ASSS to allow timely restoration of seal injection and cooling. This enhancement would reduce the CDF contribution from internal and external events that cause loss of power from the 480VAC vital buses. The proposed plant modification involves installation of 500 feet of multi-conductor cable to the control room, along with control room penetration and sealing. In addition, the modification requires control switches mounted in panels, seismic evaluations, and internal wiring. Procedure revisions and training would also be required. A bounding analysis was performed by setting the control building flooding initiators to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $1,365,046. This analysis case was used to model the benefit of Phase II SAMA 061.

480VAC Switchgear Room Flood Alarm

This analysis case was used to evaluate the change in plant risk from installing a flood alarm in the 480VAC switchgear room. The proposed modification involves installation of a single alarm and wiring from the switchgear room to the control room. Procedure revisions and training would also be required. A bounding analysis was performed by setting control building flooding initiators to zero in the level 1 PSA model, which resulted in a baseline benefit of approximately $1,365,046. This analysis case was used to model the benefit of Phase II SAMA 062.

E.4.4 Sensitivity Analyses

Three sensitivity analyses were conducted to gauge the impact of assumptions upon the analysis. The benefits estimated for each of these sensitivities are presented in Table E.4-3.

A description of each sensitivity case follows:

Sensitivity Case 1: Years Remaining Until End of Plant Life

The purpose of this sensitivity case was to investigate the sensitivity of assuming a 28-year period for remaining plant life (i.e. eight years on the original plant license plus the 20-year license renewal period). The 20-year license renewal period was used in the base case. The resultant monetary equivalent was calculated using 28 years remaining until end of facility life to investigate the impact on each analysis case. Changing this assumption does not cause additional SAMAs to be cost-beneficial.

Sensitivity Case 2: Conservative Discount Rate

The purpose of this sensitivity case was to investigate the sensitivity of each analysis case to the discount rate. The discount rate of 7.0% used in the base case analyses is conservative relative to corporate practices. Nonetheless, a lower discount rate of 3.0% was assumed in this case to investigate the impact on each analysis case. Changing this assumption does not cause additional SAMAs to be cost-beneficial.

Sensitivity Case 3: Inclusion of Economic Losses Due to Tourism and Business

The purpose of this sensitivity case was to investigate the sensitivity of each analysis case to the inclusion of economic losses due to tourism and business. The MACCS2 economic model used for the base case analysis did not consider such losses. This sensitivity case assumed a loss of $208,838/person as oppose to $163,631/person in the affected region following a postulated severe accident. This increased the calculated offsite economic cost risk for the base case and for each SAMA under consideration. Since the benefit for each SAMA is estimated as the difference between the base case and the SAMA, the sensitivity case 3 benefit values (Table E.4-3) are the same or only slightly higher than the baseline benefit values. Therefore, changing this assumption does not cause additional SAMAs to be cost-beneficial.

E.4.5 References

E.4-1 Attachment (2), Appendix F - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report - Operating License Renewal Stage, Calvert Cliffs Nuclear Power, April 1998.

E.4-2 Appendix F, Severe Accident Mitigation Alternatives Analysis Submittal Related to Licensing Renewal Application for the H.B. Robinson Steam Electric Plant Unit No.2, June 2002.

E.4-3 Appendix E, Environmental Report, Appendix F, Severe Accident Mitigation Alternatives Analysis Submittal Related to Licensing Renewal Application for the Virgil C. Summer Nuclear Station, August 2002.

E.4-4 Appendix E-Attachment E, Severe Accident Mitigation Alternatives Submittal Related to Licensing Renewal for the Arkansas Nuclear One - Unit 2, October 2003.

E.4-5 Appendix F - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report for License Renewal, Donald C. Cook Nuclear Plant, October 2003.

E.4-6 Appendix F and Appendix G - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report for Renewed Operating Licenses, Millstone Power Station, Units 2 and 3, January 2004.

E.4-7 Appendix D - Attachment F - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report - Application for License Renewal, Joseph M. Farley Nuclear Plant, September 2003.

E.4-8 Appendix E - Appendix F - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report - Application for Renewed Operating Licenses, Point Beach Nuclear Plant Units 1 and 2, February 2004.

E.4-9 Appendix F, Severe Accident Mitigation Alternatives Submittal Related to Licensing Renewal for the Quad Cities Nuclear Power Plant Units 1 and 2, January 2003.

E.4-10 General Electrical Nuclear Energy, Technical Support Document for the ABWR, 25A5680, Revision 1, January 18, 1995.

E.4-11 Cost Estimate for Severe Accident Mitigation Design Alternatives, Limerick Generating Station for Philadelphia Electric Company, Bechtel Power Corporation, June 22, 1989.

E.4-12 NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants," Volume 1, 5.35, Listing of SAMDAs considered for the Limerick Generating Station, U.S. Nuclear Regulatory Commission, May 1996.

E.4-13 NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants," Volume 1, 5.36, Listing of SAMDAs considered for the Comanche Peak Steam Electric Station, U.S. Nuclear Regulatory Commission, May 1996.

E.4-14 Letter from Mr. D. E. Nunn (TVA) to NRC Document Control Desk dated October 7, 1994, "Watts Bar Nuclear Plant (WBN) Units 1 and 2 - Severe Accident Mitigation Design Alternatives (SAMDA) - Response to Request for Additional Information (RAI) - (TAC Nos. M77222 and M77223)."

E.4-15 Letter from Mr. M. O. Medford (TVA) to NRC Document Control Desk dated September 1, 1992, "Watts Bar Nuclear Plant (WBN) Units 1 and 2 - Generic Letter (GL) 88-20 - Individual Plant Examination (IPE) for Severe Accident Vulnerabilities - Response - (TAC M74488)."

E.4-16 Letter from N. J. Liparulo (Westinghouse Electric Corporation) to NRC Document Control Desk, dated December 15, 1992, "Submittal of Material Pertinent to the AP600 Design Certification Review."

E.4-17 NUREG-1462, Final Safety Evaluation Report related to the Certification of CE System 80+ design, U.S. Nuclear Regulatory Commission, August 1994.

E.4-18 NUREG 0498, "Final Environmental Statement Related to the Operation of Watts Bar Nuclear Plant, Units 1 and 2," Supplement No. 1, U.S. Nuclear Regulatory Commission, April 1995.

E.4-19 NUREG-1560, "Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance," Volume 2, U.S. Nuclear Regulatory Commission, December 1997.

E.4-20 NUREG/CR-5474, "Assessment of Candidate Accident Management Strategies", U.S. Nuclear Regulatory Commission, March 1990.

E.4-21 IP3-RPT-MULT-01539, "Indian Point 3 Nuclear Power Plant Individual Plant Examination Revision 0, June 1994.

E.4-22 IP3-RPT-MULT-01539, "Indian Point 3 Nuclear Power Plant Individual Plant Examination Revision 1, June 2001.

E.4-23 IP-RPT-06-00071 "Indian Point Unit 3 Nuclear Power Plant Probabilistic Safety Assessment, Revision 2," April 2007.

E.4-24 P3-RPT-UNSPEC-02182, "Indian Point Three Nuclear Power Plant Individual Plant Examination for External Events," September 1997, Revision 0.

E.4-25 Appendix E, Appendix 5 - Severe Accident Mitigation Alternatives Analysis Applicant's Environmental Report for License Renewal, Fort Calhoun Unit 1 Nuclear Station, January 2002.

E.4-26 Duke Power Company, Applicant's Environmental Report, Operating License Renewal Stage, Attachment K, "McGuire Nuclear Stations Severe Accident Mitigation Alternatives (SAMA) Analysis," Rev. 0, Charlotte, North Carolina, May 2001.

E.4-27 NUREG/BR-0184 "Regulatory Analysis Technical Evaluation Handbook," U.S. Nuclear Regulatory Commission, January 1997.

E.4-28 Appendix E-Attachment E, Severe Accident Mitigation Alternatives Submittal Related to Licensing Renewal for the Palisades Nuclear Plant, March 2005.

Table E.4-1
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
201	Operator Action: Align alternate safe shutdown equipment to MCC-312A	This SAMA would align alternate safe shutdown equipment to reduce core damage frequency following 480VAC switchgear room flooding.	Already installed	This operator action is taken to align alternate safe shutdown equipment to MCC-312A to establish RCS makeup and reduce CDF following switchgear room flooding. The IP3 procedure instructs the operators to manually align 31 or 32 charging pump, 32 CCW pump and 38 service water pump to MCC-312A. Therefore, this SAMA has already been implemented at IP3.	Yes
202	Operator Action: Perform late cooldown and depressurization (SGTR)	This SAMA would terminate leakage from RCS into the secondary prior to depleting RWST inventory following a SGTR.	Already installed	This operator action is taken to cool and depressurize the RCS to cold shutdown following a SGTR to terminate leakage from RCS into the secondary prior to depleting RWST inventory. The IP3 procedure instructs the operators to perform cooldown and depressurize the RCS following a SGTR. Therefore, this SAMA has already been implemented at IP3.	Yes
203	Operator action: Recover AC power following a station blackout given successful RCS cooldown	This SAMA would reduce the CDF contribution from loss of offsite power.	Already installed	This operator action is taken to restore AC power following loss of offsite power and failure of the EDGs. The IP3 procedure instructs the operators to restore power using three sources of power: recovery of offsite power, the Appendix R diesel, and Con Ed's gas turbine No. 2. Therefore, this SAMA has already been implemented at IP3.	Yes

Table E.4-1
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights
(Continued)

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
204	Operator action: Align low head internal recirculation during a small LOCA	This SAMA would reduce the CDF contribution from small LOCA.	Already installed	This operator action is taken to align low head ECCS internal recirculation following the injection phase of ECCS to deliver flow to the RCS cold legs during a LOCA. The IP3 procedure instructs the operators to transfer to recirculation if RWST level decreases to less than 11.5 feet. Therefore, this SAMA has already been implemented at IP3.	Yes
205	Operator action: Align main feedwater for secondary heat removal	This SAMA would reduce the CDF contribution from transients.	Retain (Phase II SAMA 051)	Because the MSIVs are closed during implementation of the procedure for loss of secondary heat sink, loss of condenser vacuum results. Subsequent restoration of main feedwater is not proceduralized. Considered for a final cost-benefit evaluation, this SAMA would involve a procedure change to credit the operator re-establishing operation of the main feedwater system.	No
206	Operator action: Initiate feed and bleed cooling following loss of 480V bus 6A	This SAMA would reduce the CDF contribution from the loss of 480V bus 6A.	Already installed	This operator action is taken to establish core cooling using feed and bleed upon loss of main feedwater and all AFW pumps. The IP3 procedure instructs the operators to trip RCPs and establish an RCS bleed path. Therefore, this SAMA has already been implemented at IP3.	Yes

Table E.4-1
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights
(Continued)

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
207	Operator Action: Align backup city water cooling to charging pumps following loss of CCW	This SAMA would preclude the possibility of a large RCP seal LOCA following a loss of CCW.	Already installed	This operator action is taken to align backup city water cooling to charging pumps following a loss of CCW to preclude the possibility of a large RCP seal LOCA. The IP3 procedure instructs the operators to align charging pumps in manual at maximum speed and, if no CCW pumps can be started, align backup cooling from city water. Therefore, this SAMA has already been implemented at IP3.	Yes
208	Operator action: Initiate feed and bleed cooling following a reactor trip	This SAMA would reduce the CDF contribution from transients.	Already installed	This operator action is taken to establish core cooling using feed and bleed upon loss of main feedwater and all AFW pumps. The IP3 procedure instructs the operators to trip RCPs and establish an RCS bleed path. Therefore, this SAMA has already been implemented at IP3.	Yes
209	Operator Action: Manually insert control rods (ATWS)	This SAMA would insert control rods to reduce CDF following ATWS.	Already installed	This operator action is taken to manually insert control rods for at least one minute prior to peak RCS pressure during ATWS. The IP3 procedure instructs the operators to manually trip the reactor and enter procedure FR-S.1. If a manual trip of the reactor is not successful, FR-S.1 directs the operator to manually insert control rods. Therefore, this SAMA has already been implemented at IP3.	Yes

Table E.4-1
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights
(Continued)

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
210	Operator Action: Align alternative switchgear room ventilation	This SAMA would provide capability to provide alternate 480VAC switchgear room ventilation should the normal ventilation system fail.	Already installed	This operator action is taken to establish alternate 480VAC switchgear room cooling during large break LOCA. The IP3 alarm procedure instructs the operators to block open the doors in the 480VAC switchgear room and set up portable fans. Therefore, this SAMA has already been implemented at IP3.	Yes
211	Allow for condenser steam dump capability following an SI signal	This SAMA would reduce the CDF contribution from transients.	Already installed	A recent modification provided a more reliable source of backup cooling to the circulating water pumps following an SI signal, which reduces the likelihood that condenser vacuum will be lost and allows the use of condenser steam dumps for RCS depressurization during an SGTR event or during a LOCA involving a loss of high-head safety injection.	Yes

Table E.4-1
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights
(Continued)

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
212	Open city water supply valve for alternative AFW pump suction	This SAMA would enhance the availability of the AFW system.	Retain (Phase II SAMA 052)	This operator action is taken to recover from the plugging of condensate storage tank isolation valves CT-6 or CT-64. The plugging of these valves subsequent to a reactor trip and loss of main feedwater will cause the AFW pumps to trip on low flow, a major potential cause of loss of secondary-side cooling. The emergency operating procedure instructs the operators to align the backup city water supply to the AFW pumps should the condensate storage tank outlet valves fail, as indicated by a low suction flow alarm. The procedural guidance could be improved to direct the action to align the city water backup in the event of a low AFW suction flow alarm combined with the inability to restore adequate suction from the condensate storage tank.	No

Table E.4-1
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights
(Continued)

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
213	Provision of alternative AFW pump room ventilation	This SAMA would enhance the availability of the AFW system.	Already installed	The operator is required to establish ventilation to the AFW pump room should normal room ventilation fail. A loss of ventilation to this room while the AFW pumps are running will result in failure of the motor-driven pumps and isolation of the steam supply to the turbine-driven pump. Therefore, to guard against a loss of ventilation and its consequences when the AFW pumps start, the alarm response procedure for high pump room temperature directs the operator to open the roll-up door to the AFW pump room to ventilate the room. Therefore, this SAMA has already been implemented at IP3.	Yes
214	Provide procedural guidance for determining LOCA outside containment	This SAMA would reduce the CDF contribution from LOCA outside containment.	Already installed	IP3 emergency operating procedure for LOCA outside containment was revised to direct the operators to close both SI-899A and SI-747 (or SI-899B and SI-746). This procedural change copes with the potential to create differential pressure in excess of the design capability of SI-1869A or SI-1869B during a LOCA outside containment. Therefore, this SAMA has already been implemented at IP3.	No (although ISLOCA isolation is credited)

Table E.4-1
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights
(Continued)

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
215	Flush control building 480VAC switchgear room 15 ft elevation floor drains periodically	This SAMA would reduce the CDF contribution from 480VAC switchgear room flooding.	Already installed	IP3 preventive maintenance program has been revised to have the control building 15 ft elevation floor drains flushed during each outage. This procedural change greatly increases the likelihood that the drains at this elevation will be available to mitigate flooding in the control building and switchgear room. Therefore, this SAMA has already been implemented at IP3.	No
216	Keep both pressurizer PORV block valves open	This SAMA would reduce the CDF contribution from loss of secondary heat sink when feed and bleed is not available.	Already installed	Initiation of primary feed and bleed cooling is included in accident sequences that involve total loss of secondary side cooling and, in particular, failure to establish AFW flow. The time available to initiate feed and bleed cooling (and thus the probability of human error in taking this action) is determined by the time at which the RCPs are tripped and whether the PORV block valves are open when the reactor trip occurs. The PORVs have been replaced to eliminate leakage and allow the plant to run with the block valves open, which will enhance the likelihood of successfully initiating feed and bleed cooling. Therefore, this SAMA has already been implemented at IP3.	Yes

Table E.4-1
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights
(Continued)

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
217	Expand the scope of diesel generator functional tests	This SAMA would enhance the availability of the EDGs.	Already installed	Revision to EDG functional test procedures has been made to verify the operational status of each EDG building ventilation system. This procedure modification improves availability since potential failures will now be monitored. Therefore, this SAMA has already been implemented at IP3.	Yes
218	Revised the maintenance procedure FAN-009-AFW for AFW building ventilation system	This SAMA would improve the availability of the AFW building ventilation system.	Already installed	Maintenance procedure FAN-009-AFW for AFW building exhaust fans, louvers and dampers has been revised to improve the availability of AFW building ventilation system. Therefore, this SAMA has already been implemented at IP3.	Yes
219	Install adequate seismic support for the fire protection piping deluge valve station located in the control building at 15 ft elevation	This SAMA would reduce the CDF contribution from 480VAC switchgear room flooding.	Already installed	Adequate seismic support to the portion of the fire protection piping deluge valve station located in the control building at 15 ft elevation has been installed. In addition, a water proof door to the deluge valve station room has also been installed to reduce the CDF contribution from 480VAC switchgear room flooding. Therefore, this SAMA has already been implemented at IP3.	No (seismic-induced floods not modeled)

Table E.4-1
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights
(Continued)

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
220	Revise alarm response procedure to mitigate flood	This SAMA would reduce the CDF contribution from the PAB building flooding event.	Already installed	The alarm response procedure for flooding mitigation in the PAB has been revised. Explicit instructions were added to check whether there is flooding in the PAB on a high-level alarm. Therefore, this SAMA has already been implemented at IP3.	No
221	Reassign the power supplies to the EDG room exhaust fans	This SAMA would enhance the availability of the EDGs.	Already installed	EDG room exhaust fan power supplies have been realigned to eliminate cross-dependencies with other EDG's. Therefore, this SAMA has already been implemented at IP3.	Yes
222	Modify the power sources of backup charger 35	This SAMA would enhance the availability of backup 125VDC battery charger 35.	Already installed	Power supply to backup 125V DC battery charger 35 has been modified and is able to be powered from either 480V MCC 36C, 36D, or 36E. This allows flexibility in backup battery charger 35 to power the station batteries. Therefore, this SAMA has already been implemented at IP3.	Yes
223	Provide backup compressed air to the instrument air system	This SAMA would enhance availability of the instrument air system.	Already installed	A diesel-driven station air compressor, which can automatically supply backup, compressed air to the instrument air system in the event of low system pressure, has been installed. Therefore, this SAMA has already been implemented at IP3.	Yes

Table E.4-1
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights
(Continued)

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
224	Modify fire suppression system within the switchgear room be restored to automatic actuation.	This SAMA would reduce the CDF contribution from a 480VAC switchgear room fire.	Already installed	A modification has been implemented to change the operating mode of the CO_2 fire suppression system in the 480V switchgear room from a manually initiated automatic system to a fully automatic system. Therefore, this SAMA has already been implemented at IP3.	No (Not credited in internal PSA model)
225	Prevent spurious operation of the EDG room CO_2 system during seismic event	This SAMA would reduce the CDF contribution from seismic events.	Already installed	A modification to install a QA category I, seismic class I, actuation permission auxiliary control panel for CO_2 discharge into the EDG building was installed. This modification prevents spurious operation of the EDG room CO_2 system and subsequent shutdown of the EDG ventilation system during a seismic event. Therefore, this SAMA has already been implemented at IP3.	No (spurious CO_2 system not modeled in IPEEE)
226	Eliminate the common cause failure of EDG relays during seismic event	This SAMA would enhance the availability of the EDGs during seismic event.	Already installed	A calculation has been performed demonstrating that seismic capacity of the relays which may result in a common cause failure of all EDGs during a seismic event is adequate to withstand a safe shutdown earthquake. Therefore, this SAMA has already been implemented at IP3.	Yes

Table E.4-1
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights
(Continued)

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
227	Install an excess flow valve to reduce the risk associated with hydrogen explosions	This SAMA would reduce the risk associated with hydrogen explosions inside the turbine building or PAB.	Retain (Phase II SAMA 053)	Considered for a final cost-benefit evaluation, this modification would reduce the risk associated with hydrogen explosions by installing an excess flow valve at the outside hydrogen storage facility to stop flow in the event of a hydrogen line rupture inside the turbine building or PAB.	No
228	Provide DC power backup for the PORVs	This SAMA would reduce the CDF contribution from loss of secondary heat sink and enhance feed and bleed availability.	Retain (Phase II SAMA 054)	Considered for a final cost-benefit evaluation, this modification would involve installation of a DC power backup for the PORVs to improve the availability of PORVs to perform the feed and bleed function during a loss of secondary heat sink.	No
229	Provide hard-wired connection to one SI or RHR pump from the Appendix R bus (MCC 312A)	This SAMA would reduce the CDF contribution from internal flooding scenarios.	Retain (Phase II SAMA 055)	Considered for a final cost-benefit evaluation, this modification would involve providing a power source for one SI or RHR pump from the Appendix R bus (MCC 312A) during internal flooding scenarios in the control building at 15 ft elevation.	No

Table E.4-1
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights
(Continued)

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
230	Install pneumatic controls and indication for the turbine-driven AFW pump	This SAMA would reduce the CDF contribution from SBO events.	Retain (Phase II SAMA 056)	Considered for a final cost-benefit evaluation, this modification would involve Installing pneumatic controls and indication for the turbine-driven AFW pump to reduce the CDF contribution from SBO events.	No
231	Provide backup cooling water source for the CCW heat exchangers	This SAMA would reduce the CDF contribution from loss of non-essential service water events	Retain (Phase II SAMA 057)	Considered for a final cost-benefit evaluation, this would involve using the IP3 backup service water pumps to provide cooling for the CCW heat exchangers on loss of non-essential service water. Currently, the backup service water pumps are only aligned to provide backup to the essential service water header.	No
232	Provide alternate source of water to the fan cooler units following loss of all service water	This SAMA would reduce the CDF associated with loss of essential service water.	Already installed	IP3 has the capability to supply the essential service water loads from the backup service water pumps, which are separate from the normal service water system.	No (Not credited in internal PSA model)
233	Provide automatic DC power backup	This SAMA would reduce the CDF associated with loss of a DC bus.	Retain (Phase II SAMA 058)	Similar to a capability that already exists at IP2, provide DC power backup using transfer switches that would automatically provide alternate DC power from another DC panel in the event of low output from the normal DC supply.	No

Table E.4-1
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights
(Continued)

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
234	Provide hardware connections to allow the primary water system to be used to cool the charging pumps	This SAMA would reduce the effect of loss of CCW by providing an alternate means to cool the charging pumps and preserve seal injection after a loss of CCW.	Retain (Phase II SAMA 059)	Considered for a final cost-benefit evaluation, this modification would involve installing the necessary connections and implementing procedure changes to allow primary water to supply cooling to the charging pumps on loss of CCW.	No
235	Provide independent source of cooling for the recirculation pump motors	This SAMA would reduce the CDF associated with loss of CCW events	Retain (Phase II SAMA 060)	Considered for a final cost-benefit evaluation, this modification would involve installing the necessary connections and implementing procedure changes to allow an alternate source (city water or primary water) to supply cooling to the recirculation pumps on loss of CCW.	No

Table E.4-1
Phase I SAMAs Related to IPE, PSA Model Updates and IPEEE Insights
(Continued)

Phase I SAMA ID Number	SAMA Title	Result of Potential Enhancement	Screening Criteria	SAMA Disposition	Credited in PSA Model
236	Upgrade the ASSS to allow timely restoration of seal injection and cooling.	This SAMA would reduce the CDF contribution from internal and external events that cause loss of power from the 480V vital buses (SBO, control building floods and fires)	Retain (Phase II SAMA 061)	Considered for a final cost-benefit evaluation, this modification would involve providing an automatic start and load feature for the alternate safe shutdown power source.	No
237	Install flood alarm in the 480VAC switchgear room	This SAMA would reduce CDF from switchgear room flooding.	Retain (Phase II SAMA 062)	Considered for a final cost-benefit evaluation, this SAMA would involve procedure and hardware changes to reduce CDF following control building 480VAC switchgear room flooding.	No

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Diesel Powered RCP Seal Injection 001 - Create an independent RCP seal injection system with a dedicated diesel.	Eliminate consequential RCP seal LOCAs from all plant initiators. The cost of implementing this SAMA was specifically estimated for IP3.	6.87%	0.82%	0.57%	$135,611	$196,538	$1,137,000	Not cost effective
Non-Diesel Powered RCP Seal Injection 002 - Create an independent RCP seal injection system without a dedicated diesel.	Eliminate consequential RCP seal LOCAs from non-SBO events. The cost of implementing this SAMA was specifically estimated for Donald C. Cook.	5.05%	0.41%	0.57%	$100,223	$145,251	$1,000,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Additional CCW Pump 003 - Install an additional CCW pump.	Eliminate common cause failure of CCW pumps. The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.	0.11%	0.00%	0.00%	~$0	~$0	$1,500,000	Not cost effective
RHR Heat Exchangers 004 - Improve ability to cool the RHR heat exchangers by allowing manual alignment of the fire protection system.	Eliminate loss of CCW to the RHR heat exchangers. The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	0.65%	0.41%	0.38%	$35,517	$51,474	$565,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Filtered Containment Vent 005 - Install a filtered containment vent to provide fission product scrubbing.	Eliminate late containment over-pressurization failures. The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	0.00%	9.80%	7.01%	$504,995	$731,877	$5,700,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Molten Core Debris Removal	Eliminate containment failure due to CCI.	0.00%	24.08%	21.59%	$1,378,340	$1,997,594		
006 - Create a large concrete crucible with heat removal potential under the base mat to contain molten core debris.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						$108,000,000	Not cost effective
007 - Create a reactor cavity flooding system.	The cost of implementing this SAMA was specifically estimated for IP2.						$3,714,000	Not cost effective
008 - Create a core melt source reduction system.	The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.						$90,000,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Inert Containment 009 - Provide means to inert containment.	Eliminate containment failures due to hydrogen burns. The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	0.00%	8.57%	9.66%	$552,524	$800,760	$10,900,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Containment Sprays	Eliminate failure of containment spray.	0.11%	0.00%	0.00%	~$0	~$0		
010 - Use the fire protection system as a backup source for the containment spray system.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						$565,000	Not cost effective
011 - Install a passive containment spray system.	The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.						$2,000,000	Not cost effective
014 - Install a redundant containment spray system.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						$5,800,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Base Mat Melt-Through 012 - Increase the depth of the concrete base mat or use an alternative concrete material to ensure melt-through does not occur.	Eliminate containment failure due to base mat melt-through. The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.	0.00%	5.71%	4.17%	$297,056	$430,516	>$5,000,000	Not cost effective
Strengthen Containment 013 - Construct a building connected to primary containment that is maintained at a vacuum.	Eliminate energetic containment failure modes (DCH, steam explosion, late over-pressurization). The cost of implementing this SAMA was specifically estimated for IP3.	0.00%	21.63%	20.45%	$1,271,400	$1,842,609	$61,000,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Containment Liner Protection 015 - Erect a barrier that provides containment liner protection from ejected core debris at high pressure.	Eliminate HPME and subsequent DCH at high RCS pressure. The cost of implementing this SAMA was specifically estimated for IP3.	0.11%	4.08%	4.36%	$255,468	$370,244	$2,900,000	Not cost effective
Steam Generator Heat Removal 016 - Install a highly reliable steam generator shell-side heat removal system that relies on natural circulation and stored water sources.	Eliminate SGTR with loss of secondary-side cooling. The cost of implementing this SAMA was specifically estimated for IP3.	2.47%	5.31%	5.30%	$356,079	$516,057	$7,400,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Secondary Side Pressure Capacity 017 - Increase secondary side pressure capacity such that an SGTR would not cause the relief valves to lift.	Eliminate operator failure to isolate the ruptured steam generator. The cost of implementing this SAMA was specifically estimated for IP3.	8.57%	44.90%	47.35%	$2,909,856	$4,217,182	$13,000,000	Not cost effective
SGTR Fission Product Scrubbing 018 - Route the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove most of the fission products.	Reduce SGTR accident progression source terms by a factor of 2. The cost of implementing this SAMA was specifically estimated for IP3.	0.00%	11.43%	10.61%	$665,406	$964,356	$9,700,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
ISLOCA Mitigation	Eliminate ISLOCAs.	1.26%	6.94%	7.39%	$457,208	$662,620		
019 - Install additional pressure or leak monitoring instrumentation for ISLOCAs.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						$2,300,000	Not cost effective
022 - Ensure all ISLOCA releases are scrubbed.	The cost of implementing this SAMA was specifically estimated for IP3.						$9,700,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
ISLOCA Valves	Reduce ISLOCAs by 50 percent.	0.68%	3.27%	3.60%	$219,692	$318,394		
020 - Add redundant and diverse limit switches to each containment isolation valve.	The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.						$1,000,000	Not cost effective
021 - Increase leak testing of valves in ISLOCA paths.	The cost of implementing this SAMA was specifically estimated for IP3.						$10,604,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
MSIV Design 023 - Improve MSIV design.	Eliminate MSIV failure to isolate a faulted or ruptured steam generator. The cost of implementing this SAMA was specifically estimated for IP3.	0.11%	0.00%	0.00%	~$0	~$0	$476,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
DC Power/ AFW System Changes	Increase time available to recover offsite power before local operation of AFW is required from 2 hours to 24 hours during SBO scenarios.	2.81%	0.00%	0.00%	$35,259	$51,100		
024 - Provide additional DC battery capacity.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						>$1,875,000	Not cost effective
025 - Use fuel cells instead of lead-acid batteries.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						$2,000,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
026 - Increase/ improve DC bus load shedding.	The cost of implementing this SAMA was specifically estimated for Fort Calhoun Unit 1.						>$160,000	Not cost effective
042 - Provide hookup for portable generators to power the turbine-driven AFW pump after station batteries are depleted.	The cost of implementing this SAMA was specifically estimated for IP3.						$1,072,000	Not cost effective
056 - Install pneumatic controls and indication for the turbine-driven AFW pump.	The cost of implementing this SAMA was specifically estimated for IP3.						$982,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
AC Power Cross-Tie with IP2 027 - Create AC power cross-tie capability with other unit.	Eliminate loss of the Appendix R diesel. The cost of implementing this SAMA was specifically estimated for IP3.	4.50%	0.00%	0.00%	$58,765	$85,166	$1,156,000	Not cost effective
EDG Alternate Engine Cooling	Eliminate loss of the essential service water supply for EDG cooling.	0.56%	0.00%	0.00%	$11,753	$17,033		
028 - Create a backup source for diesel cooling (not from existing system).	The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.						$1,700,000	Not cost effective
029 - Use fire protection system as a backup source for diesel cooling.	The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.						$497,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Alternate Battery Charger Capability 030 - Provide a portable diesel-driven battery charger.	Reduce internal switchgear room floods 5 percent to account for local operation of the turbine-driven AFW pump; and increase the time available to recover offsite power before local operation of AFW is required from 2 hours to 24 hours during SBO scenarios. The cost of implementing this SAMA was specifically estimated for IP3.	8.73%	6.94%	6.06%	$509,643	$738,613	$494,000	Retain

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Improve 118VAC System 031 - Convert under-voltage, AFW and reactor protective system actuation signals from 2-out-of-4 to 3-out-of-4 logic.	Eliminate common cause failure of the 118VAC transformers. The cost of implementing this SAMA was specifically estimated for IP3.	0.33%	0.41%	0.38%	$23,764	$34,441	$1,254,000	Not cost effective
Low Pressure Injection System 032 - Provide capability for diesel-driven, low pressure vessel makeup. 035 - Provide capability for alternate injection via diesel-driven fire pump.	Eliminate failure of the RHR system. The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2. The cost of implementing this SAMA was specifically estimated for IP3.	0.24%	0.00%	0.19%	$5,941	$8,610	$>632,000 $750,000	Not cost effective Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
High Pressure Injection System	Eliminate failure of the safety injection system.	0.39%	0.41%	0.38%	$35,517	$51,474		
033 - Provide an additional high pressure injection pump with independent diesel.	The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.						$5,000,000	Not cost effective
037 - Replace two of three motor-driven SI pumps with diesel-powered pumps.	The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.						$2,000,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Automatic Recirculation Cooling Swap-Over 034 - Create automatic swap-over to recirculation cooling upon RWST depletion.	Eliminate operator failure to align internal and external recirculation cooling. The cost of implementing this SAMA was specifically estimated for McGuire.	19.86%	1.22%	1.14%	$340,435	$493,384	>$1,000,000	Not cost effective
Conserve RWST Water Inventory 036 - Throttle low pressure injection pumps earlier in medium or large-break LOCAs to maintain reactor water storage tank inventory.	Eliminate operator failure to align internal and external recirculation cooling during a large or medium LOCA. The cost of implementing this SAMA was specifically estimated for IP3.	0.86%	0.00%	0.00%	$11,753	$17,033	$82,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Enhance RCS Depressurization 038 - Create/ enhance a reactor coolant depressurization system.	Eliminate common cause failure of the steam generator ADVs. The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.	0.55%	0.82%	0.95%	$65,223	$94,526	$4,600,000	Not cost effective
Main Feedwater System Upgrade 039 - Install a digital feed water upgrade. 041 - Add a motor-driven feedwater pump.	Eliminate loss of feedwater initiator. The cost of implementing this SAMA was specifically estimated for Joseph M. Farley. The cost of implementing this SAMA was specifically estimated for Joseph M. Farley.	11.84%	0.82%	0.57%	$206,128	$298,737	$900,000 $2,200,000	Not cost effective Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Steam Generator Atmospheric Steam Dump Valve Enhancement 040 - Provide automatic nitrogen backup to steam generator ADVs.	Eliminate failure of manual local action to align nitrogen supply for control air supply to the steam generator ADV control valve. The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	0.51%	0.82%	0.95%	$65,223	$94,526	$214,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Alternate Water Sources to Steam Generators 043 - Use fire water system as backup for steam generator inventory.	Eliminate failure of the turbine-driven AFW pump and failure to restore AC power given successful AFW operation. The cost of implementing this SAMA was specifically estimated for IP3.	6.75%	1.63%	1.33%	$183,140	$265,420	$1,656,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Install Large Pressurizer PORVs 044 - Replace current pilot operated relief valves with larger ones such that only one is required for successful feed and bleed.	Change the number of PORVs required for RCS feed and bleed from 2-of-2 to 1-of-2. In addition, reduce failure of the operator action for feed and bleed by a factor of 5. The cost of implementing this SAMA was specifically estimated for Calvert Cliffs.	4.46%	4.49%	4.73%	$337,997	$489,851	$2,700,000	Not cost effective
Independent Boron Injection System 045 - Add an independent boron injection system.	Eliminate common cause failure of boric acid transfer pumps. The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.	0.16%	0.00%	0.00%	~$0	~$0	$300,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
ATWS Overpressure Protection 046 - Add a system of relief valves that prevent equipment damage from a pressure spike during an ATWS.	Eliminate RCS overpressurization during an ATWS. The cost of implementing this SAMA was specifically estimated for IP3.	10.28%	0.82%	0.38%	$176,682	$256,060	$615,000	Not cost effective
Control Room ATWS Mitigation	Eliminate failure to trip the control rod motor generator sets.	1.60%	0.00%	0.00%	$23,506	$34,066		
047 - Install motor generator set trip breakers in control room.	The cost of implementing this SAMA was specifically estimated for IP3.						$716,000	Not cost effective
048 - Provide capability to remove power from the bus powering the control rods.	The cost of implementing this SAMA was specifically estimated for IP3.						$45,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Large Break LOCA 049 - Provide digital large break LOCA protection.	Eliminate large break LOCA initiator. The cost of implementing this SAMA was specifically estimated for IP3.	0.30%	0.00%	0.00%	~$0	~$0	$2,036,000	Not cost effective
Main Steam Line Break Inside Containment 050 - Install secondary side guard pipes up to the MSIVs.	Eliminate main steam line break initiators (inside and outside containment). The cost of implementing this SAMA was specifically estimated for Arkansas Nuclear One Unit 2.	4.67%	8.98%	9.28%	$611,289	$885,926	$1,100,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Main Feedwater Secondary Side Cooling 051 - Operator action: Align main feedwater for secondary heat removal.	Eliminate failure of condensate secondary side cooling. The cost of implementing this SAMA was specifically estimated for IP3.	0.65%	0.00%	0.00%	$11,753	$17,033	$55,000	Not cost effective
AFW Alternate Suction Supply 052 - Open city water supply valve for alternative AFW pump suction.	Eliminate loss of the normal suction path to the AFW system. The cost of implementing this SAMA was specifically estimated for IP3.	0.89%	0.82%	0.95%	$65,223	$94,526	$50,000	Retain

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Plant Hydrogen Control 053 - Install an excess flow valve to reduce the risk associated with hydrogen explosions.	Eliminate hydrogen ruptures inside the turbine building. The cost of implementing this SAMA was specifically estimated for IP3.	1.79%	2.00%	1.86%	$142,328	$206,273	$228,000	Not cost effective
Pressurizer PORV DC Power 054 - Provide DC power backup for the PORVs.	Eliminate failure of DC power to the PORVs. The cost of implementing this SAMA was specifically estimated for IP3.	0.20%	0.00%	0.00%	~$0	~$0	$376,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Appendix R Power SI or RHR Pump 055 - Provide hard-wired connection to one SI or RHR pump from the Appendix R bus (MCC 312A).	Eliminate operator failure to align MCC 312A. The cost of implementing this SAMA was specifically estimated for IP3.	16.48%	18.37%	16.48%	$1,274,884	$1,847,657	$1,288,000	Retain
CCW Heat Exchanger Alternate Cooling Supply 057 - Provide backup cooling water source for the CCW heat exchangers.	Eliminate loss of non-essential service water initiator. The cost of implementing this SAMA was specifically estimated for IP3.	2.51%	0.00%	0.00%	$35,259	$51,100	$109,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Backup DC Power Supply 058 - Provide automatic DC power backup.	Eliminate loss of DC Bus 31 and Bus 32 initiators. The cost of implementing this SAMA was specifically estimated for IP3.	4.83%	0.00%	0.19%	$76,459	$110,809	$1,868,000	Not cost effective
Charging Pump Alternate Cooling 059 - Provide hardware connections to allow the primary water system to cool the charging pumps.	Eliminate failure to align city water to the charging pumps. The cost of implementing this SAMA was specifically estimated for IP3.	0.19%	0.00%	0.00%	~$0	~$0	$576,000	Not cost effective

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
Recirculation Pump Motor Alternate Cooling 060 - Provide independent source of cooling for the recirculation pump motors.	Eliminate loss of CCW to the recirculation pumps. The cost of implementing this SAMA was specifically estimated for IP3.	0.20%	0.00%	0.00%	~$0	~$0	$710,000	Not cost effective
Upgrade ASSS for RCP Seal Cooling 061 - Upgrade the ASSS to allow timely restoration of seal injection and cooling.	Eliminate control building flooding initiators. The cost of implementing this SAMA was specifically estimated for IP3.	17.43%	19.59%	17.80%	$1,365,046	$1,978,328	$560,000	Retain

Table E.4-2
Summary of Phase II SAMA Candidates Considered in Cost-Benefit Evaluation
(Continued)

Phase II SAMA	Assumptions	CDF Reduction	Offsite Dose Reduction	OECR Reduction	Baseline Benefit	Baseline Benefit With Uncertainty	Estimated Cost	Conclusion
480VAC Switchgear Room Flood Alarm 062 - Install flood alarm in the 480VAC switchgear room.	Eliminate control building flooding initiators. The cost of implementing this SAMA was specifically estimated for IP3.	17.43%	19.59%	17.80%	$1,365,046	$1,978,328	$196,800	Retain

Table E.4-3
Sensitivity Analysis Results

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Diesel Powered RCP Seal Injection 001 - Create an independent RCP seal injection system with a dedicated diesel.	$135,611	$177,227	$161,294	$141,552	$1,137,000
Non-diesel Powered RCP Seal Injection 002 - Create an independent RCP seal injection system without a dedicated diesel.	$100,223	$131,227	$118,895	$100,223	$1,000,000
Additional CCW Pump 003 - Install an additional CCW pump.	~$0	~$0	~$0	~$0	$1,500,000

Table E.4-3
Sensitivity Analysis Results
(Continued)

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
RHR Heat Exchangers 004 - Improved ability to cool the RHR heat exchangers by allowing manual alignment of the fire protection system.	$35,517	$43,325	$46,105	$41,459	$565,000
Filtered Containment Vent 005 - Install a filtered containment vent to provide fission product scrubbing.	$504,995	$575,870	$705,659	$534,701	$5,700,000

Table E.4-3
Sensitivity Analysis Results
(Continued)

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Molten Core Debris Removal	$1,378,340	$1,571,787	$1,926,033	$1,467,457	
006 - Create a large concrete crucible with heat removal potential under the base mat to contain molten core debris.					$108,000,000
007 - Create a reactor cavity flooding system.					$8,750,000
008 - Create a core melt source reduction system.					$90,000,000
Inert Containment 009 - Provide means to inert containment.	$552,524	$630,070	$772,074	$594,112	$10,900,000

Table E.4-3
Sensitivity Analysis Results
(Continued)

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Containment Sprays	~$0	~$0	~$0	~$0	
010 - Use the fire protection system as a backup source for the containment spray system.					$565,000
011 - Install a passive containment spray system.					$2,000,000
014 - Install a redundant containment spray system.					$5,800,000
Base Mat Melt-Through	$297,056	$338,747	$415,093	$308,938	>$5,000,000
012 - Increase the depth of the concrete base mat or use an alternative concrete material to ensure melt-through does not occur.					

Table E.4-3
Sensitivity Analysis Results
(Continued)

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Strengthen Containment 013 - Construct a building connected to primary containment that is maintained at a vacuum.	$1,271,400	$1,449,838	$1,776,599	$1,354,576	$61,000,000
Containment Liner Protection 015 - Erect a barrier that provides containment liner protection from ejected core debris at high pressure.	$255,468	$291,323	$356,980	$273,292	$2,900,000
Steam Generator Heat Removal 016 - Install a highly reliable steam generator shell-side heat removal system that relies on natural circulation and stored water sources.	$356,079	$414,523	$486,994	$379,844	$7,400,000

Table E.4-3
Sensitivity Analysis Results
(Continued)

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Secondary Side Pressure Capacity 017 - Increase secondary side pressure capacity such that an SGTR would not cause the relief valves to lift.	$2,909,856	$3,346,478	$4,030,853	$3,141,560	$13,000,000
SGTR Fission Product Scrubbing 018 - Route the discharge from the main steam safety valves through a structure where a water spray would condense the steam and remove most of the fission products.	$665,406	$758,794	$929,809	$724,817	$9,700,000

Table E.4-3
Sensitivity Analysis Results
(Continued)

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
ISLOCA Mitigation	$457,208	$527,022	$631,831	$498,795	
019 - Install additional pressure or leak monitoring instrumentation for ISLOCAs.					$2,300,000
022 - Ensure all ISLOCA releases are scrubbed.					$9,700,000
ISLOCA Valves	$219,692	$253,348	$303,463	$243,457	
020 - Add redundant and diverse limit switches to each containment isolation valve.					$1,000,000
021 - Increase leak testing of valves in ISLOCA paths.					$10,604,000
MSIV Design	~$0	~$0	~$0	~$0	$476,000
023 - Improve MSIV Design.					

Table E.4-3
Sensitivity Analysis Results
(Continued)

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
DC Power/ AFW System Changes	$35,259	$48,676	$38,693	$35,259	
024 - Provide additional DC battery capacity.					>$1,875,000
025 - Use fuel cells instead of lead-acid batteries.					$2,000,000
026 - Increase/ improve DC bus load shedding.					>$160,000
042 - Provide hookup for portable generators to power the turbine-driven AFW pump after station batteries are depleted.					$1,072,000
056 - Install pneumatic controls and indication for the turbine-driven AFW pump.					$982,000

Table E.4-3
Sensitivity Analysis Results
(Continued)

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
AC Power Cross-Tie with IP2 027 - Create AC power cross-tie capability with other unit.	$58,765	$81,127	$64,448	$64,706	$1,156,000
EDG Alternate Engine Cooling 028 - Create a backup source for diesel cooling (not from existing system). 029 - Use fire protection system as a backup source for diesel cooling.	$11,753	$16,225	$12,898	$11,753	 $1,700,000 $497,000
Alternate Battery Charger Capability 030 - Provide a portable diesel-driven battery charger.	$509,643	$609,400	$676,899	$551,231	$494,000

Table E.4-3
Sensitivity Analysis Results
(Continued)

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Improve 118VAC System 031 - Convert under-voltage, AFW and reactor protective system actuation signals from 2-out-of-4 to 3-out-of-4 logic.	$23,764	$27,100	$33,207	$29,706	$1,254,000
Low Pressure Injection System 032 - Provide capability for diesel-driven, low pressure vessel makeup. 035 - Provide capability for alternate injection via diesel-driven fire pump.	$5,941	$6,775	$8,302	$5,941	 >$632,000 $750,000

**Table E.4-3
Sensitivity Analysis Results
(Continued)**

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
High Pressure Injection System	$35,517	$43,325	$46,105	$35,517	
033 - Provide an additional high pressure injection pump with independent diesel.					$5,000,000
037 - Replace two of three motor-driven SI pumps with diesel-powered pumps.					$2,000,000
Automatic Recirculation Cooling Swap-Over	$340,435	$452,860	$394,978	$346,376	>$1,000,000
034 - Create automatic swap-over to recirculation upon RWST depletion.					

Table E.4-3
Sensitivity Analysis Results
(Continued)

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Conserve RWST Water Inventory 036 - Throttle low pressure injection pumps earlier in medium or large-break LOCAs to maintain reactor water storage tank inventory.	$11,753	$16,225	$12,898	$11,753	$82,000
Enhance RCS Depressurization 038 - Create/enhance a reactor coolant depressurization system.	$65,223	$77,200	$87,614	$71,164	$4,600,000
Main Feedwater System Upgrade 039 - Install a digital feed water upgrade. 041 - Add a motor-driven feedwater pump.	$206,128	$274,580	$238,680	$212,070	 $900,000 $2,000,000

Table E.4-3
Sensitivity Analysis Results
(Continued)

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Steam Generator Atmospheric Steam Dump Valve Enhancement 040 - Provide automatic nitrogen backup to steam generator ADVs.	$65,223	$77,200	$87,614	$65,223	$214,000
Alternate Water Sources to Steam Generators 043 - Use fire water system as backup for steam generator inventory.	$183,140	$231,427	$227,709	$195,022	$1,656,000
Install Large Pressurizer PORVs 044 - Replace current pilot operated relief valves with larger ones such that only one is required for successful feed and bleed.	$337,997	$399,549	$454,676	$355,821	$2,700,000

Table E.4-3
Sensitivity Analysis Results
(Continued)

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Independent Boron Injection System 045 - Add an independent boron injection system.	~$0	~$0	~$0	~$0	$300,000
ATWS Overpressure Protection 046 - Add a system of relief valves that prevent equipment damage from a pressure spike during an ATWS.	$176,682	$235,354	$204,583	$182,623	$615,000
Control Room ATWS Mitigation 047 - Install motor generator set trip breakers in control room. 048 - Provide capability to remove power from the bus powering the control rods.	$23,506	$32,451	$25,795	$23,506	 $716,000 $45,000

Table E.4-3
Sensitivity Analysis Results
(Continued)

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Large Break LOCA 049 - Provide digital large break LOCA protection.	~$0	~$0	~$0	~$0	$2,036,000
Main Steam Line Break Inside Containment 050 - Install secondary side guard pipes up to the MSIVs.	$611,289	$711,197	$836,562	$646,935	$1,100,000
Main Feedwater Secondary Side Cooling 051 - Operator action: Align main feedwater for secondary heat removal.	$11,753	$16,225	$12,898	$11,753	$55,000
AFW Alternate Suction Supply 052 - Open city water supply valve for alternative AFW pump suction.	$65,223	$77,200	$87,614	$71,164	$50,000

Table E.4-3
Sensitivity Analysis Results
(Continued)

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Plant Hydrogen Control 053 - Install an excess flow valve to reduce the risk associated with hydrogen explosions.	$142,328	$167,950	$191,833	$160,152	$228,000
Pressurizer PORV DC Power 054 - Provide DC power backup for the PORVs.	~$0	~$0	~$0	~$0	$376,000
Appendix R Power to SI or RHR Pump 055 - Provide hard-wired connection to one SI or RHR pump from the Appendix R bus (MCC 312A).	$1,274,884	$1,507,447	$1,714,485	$1,346,177	$1,288,000

Table E.4-3
Sensitivity Analysis Results
(Continued)

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
CCW Heat Exchanger Alternate Cooling Supply 057 - Provide backup cooling water source for the CCW heat exchangers.	$35,259	$48,676	$38,693	$41,200	$109,000
Backup DC Power Supply 058 - Provide automatic DC power backup.	$76,459	$104,127	$85,688	$76,459	$1,868,000
Charging Pump Alternate Cooling 059 - Provide hardware connections to allow the primary water system to cool the charging pumps.	~$0	~$0	~$0	~$0	$576,000

Table E.4-3
Sensitivity Analysis Results
(Continued)

Phase II SAMA	Baseline Benefit 20 yrs Remaining, 7% Discount Rate	Sensitivity Case 1 28 yrs Remaining, 7% Discount Rate	Sensitivity Case 2 20 yrs Remaining, 3% Discount Rate	Sensitivity Case 3 Baseline with Loss of Tourism and Business	Estimated Cost
Recirculation Pump Motor Alternate Cooling 060 - Provide independent source of cooling for the recirculation pump motors.	~$0	~$0	~$0	~$0	$710,000
Upgrade ASSS for RCP Seal Cooling 061 - Upgrade the ASSS to allow timely restoration of seal injection and cooling.	$1,365,046	$1,613,369	$1,836,597	$1,436,340	$560,000
480VAC Switchgear Room Flood Alarm 062 - Install flood alarm in the 480Vac switchgear room.	$1,365,046	$1,613,369	$1,836,597	$1,436,340	$196,800