Florida Power & Light Company, 6501 South Ocean Drive, Jensen Beach, FL 34957

June 25, 2002

FPL

L-2002-124
10 CFR 54

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D.C. 20555

Re: St. Lucie Units 1 and 2
Docket Nos. 50-335 and 50-389
Response to NRC Request for Additional Information Related to the Staff's Review of Severe Accident Mitigation Alternatives for St. Lucie Units 1 and 2

By letter dated May 7, 2002, the NRC requested additional information regarding the St. Lucie Units 1 and 2 License Renewal Application (LRA) Environmental Report Severe Accident Management Alternatives. Attachment 1 to this letter contains FPL's response to the requests for additional information (RAIs) associated with the Severe Accident Mitigation Alternatives of the LRA Environmental Report.

Should you have any further questions, please contact S. T. Hale at (772) 467-7430.

Very truly yours,

D. E. Jernigan
Vice President
St. Lucie Plant

DEJ/STH/hlo
Attachment (1)

A089

St. Lucie Units 1 and 2
Docket Nos. 50-335 and 50-389

Response to NRC Request for Additional Information Related to the Staff's Review of Severe Accident Mitigation Alternatives for St. Lucie Units 1 and 2

STATE OF FLORIDA)
) ss
COUNTY OF ST. LUCIE)

D. E. Jernigan being first duly sworn, deposes and says:

That he is Vice President – St. Lucie of Florida Power and Light Company, the Licensee herein;

That he has executed the foregoing document; that the statements made in this document are true and correct to the best of his knowledge, information and belief, and that he is authorized to execute the document on behalf of said Licensee.

D. E. Jernigan

Subscribed and sworn to before me this

25 day of June, 2002.

Leslie J. Whitwell

Name of Notary Public (Type or Print)

Leslie J. Whitwell
MY COMMISSION # DD020212 EXPIRES
May 12, 2005
BONDED THRU TROY FAIN INSURANCE, INC.

D. E. Jernigan is personally known to me.

cc: U.S. Nuclear Regulatory Commission, Washington, D.C.

Program Director, License Renewal and Environmental Impacts
Project Manager – St. Lucie License Renewal
Project Manager - St. Lucie

U.S. Nuclear Regulatory Commission, Region II
Regional Administrator, Region II, USNRC
Senior Resident Inspector, USNRC, Turkey Point Plant

Other

Mr. Robert Butterworth
Attorney General
Department of Legal Affairs
The Capitol
Tallahassee, FL 32399-1050

Mr. William A. Passetti, Chief
Department of Health
Bureau of Radiation Control
2020 Capital Circle, SE, Bin #C21
Tallahassee, FL 32399-1741

Mr. Craig Fugate, Director
Division of Emergency Preparedness
Department of Community Affairs
2740 Centerview Drive
Tallahassee, FL 32399-2100

Mr. Douglas Anderson
County Administrator
St. Lucie County
2300 Virginia Avenue
Fort Pierce, FL 34982

Mr. Jim Kammel
Radiological Emergency Planning Administrator
Department of Public Safety
6000 SE Tower Drive
Stuart, FL 34997

Mr. Alan Nelson
Nuclear Energy Institute
1776 I Street NW
Suite 400
Washington, D.C. 20006

ATTACHMENT 1
RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION TO THE STAFF'S REVIEW OF THE SEVERE ACCIDENT MANAGEMENT ALTERNATIVES (SAMA) FOR ST. LUCIE UNITS 1 AND 2

QUESTION 1

The SAMA analysis appears to be based on the current version of the "living" PSA model for internal events, which is a modification to the original Individual Plant Examination (IPE) that was reviewed by the U. S. Nuclear Regulatory Commission (NRC). Please provide the following:

a. the date and/or version of the PSA used for the SAMA analysis, and a description of the internal and external peer review of the level 1, 2, and 3 portions of this PSA,

b. a description of the major differences between the PSA and the IPE, including the plant and/or modeling changes that have resulted in the new core damage frequency (CDF) and release frequencies,

c. a breakdown of the internal event CDF for each unit by initiating event, specifically, Loss of Offsite Power (LOOP), General Transients, Station Blackout, ATWS, Loss-of-Coolant Accidenta (LOCAs), Interfacing System LOCA (ISLOCA), and Steam Generator Tube Rupture (SGTR), and other internal events initiators (please specify). Also, confirm the total of 2.99×10^{-5} per reactor year for Unit 1 and 2.44×10^{-5} per reactor year, for Unit 2, respectively.

d. the specific reasons for the major differences in the total CDF for the two units. This should include the reasons for the differences in the CDF due to SGTR and ISLOCA initiators. (The information provided in Appendix E. e.g., Section E.1.1, is not complete for the purpose of this review.)

e. an estimate of the uncertainties associated with the calculated core damage frequency (e.g., the mean and median CDF estimates and the 5th and 95th percentile values of the uncertainty distribution).

f. a breakdown of the population dose (person-rem per year) by containment release mode in the following form:

Containment Release Mode	Fraction of Population Dose	
	Unit 1	Unit 2
SGTR (Late and Early)		
Interfacing Systems LOCAs		
Early containment failure		
Late containment failure		
No containment failure		

g. an explanation of the differences in the SGTR1 and SGTR2 ("late" and "early") release modes, and the reasons for the low release magnitudes and the absence of tellurium releases for these release modes. In addition, please provide, separately, the contribution of hydrogen and CO combustion to early and late containment failure probability.

h. a list of key equipment failures and human actions that dominate CDF and population dose (or alternatively, the large early and late release frequencies), and have the greatest results of any supporting importance analyses (e.g., Fussel-Vesely and/or risk reduction importance measures).

Response to QUESTION 1:

a. The Risk Model used for each St. Lucie Unit was the model updated in April 2001. The Level 1 and Level 2 portion of the probabilistic safety assessment (PSA) model update were documented via calculation or evaluation and reviewed independently and approved in accordance with the FPL Quality Assurance (QA) Program procedures and FPL Reliability and Risk Assessment Group (RRAG) standards. The Level 1 model was also compared with the Combustion Engineering Owners Group (CEOG) plants via CEOG PSA subcommittee cross-comparison projects for dominant risk attributes. The cross-comparison was performed as a part of the Emergency Diesel Generator (EDG) Allowed Outage Time (AOT) Extension project. No issues were identified that warranted resolution for the EDG AOT extension. The EDG AOT extension for St. Lucie Units 1 and 2 was approved in 2001. The Level 3 PSA model was provided by Scientech and was independently reviewed by its staff and FPL staff.

b. A description of the differences between the PSA and the IPE, including the plant and/or modeling changes that have resulted in the new CDF and release frequencies is contained in the Applicant's Environmental Report Operating License Renewal Stage, Appendix E Section E.1.1.1.

c. Individual sequences associated with various Plant Damage States (PDSs) were quantified separately and then totaled, yielding frequencies of 2.99E-05 per reactor year and 2.44E-05 per reactor year (including ISLOCA) for Unit 1 and Unit 2, respectively. An alternate quantification based on an "OR" gate containing all PDS sequences produced frequencies of 2.86E-05 per reactor year and 2.43E-05 per reactor year, respectively. The following is based on the one-top PDS results. The individual sequence for various PDSs were used for Level 3 analysis.

Table 1-1
Breakdown of Internal CDF Sorted by Initiating Events

Initiating Event	Frequency (per Year)	
	Unit 1	Unit 2
Loss of Offsite Power/Station Blackout [1]	4.63E-06	2.67E-06
Transients [2]	4.55E-06	1.84E-06
Anticipated Transient Without Scram	8.23E-07	3.31E-07
Loss-of-Coolant Accident	8.22E-06	7.51E-08
ISLOCA	2.89E-06	5.64E-06
SGTR	9.58E-07	2.78E-07
Internal floods	5.00E-07	5.00E-07
Others [3]	6.03E-06	1.30E-05
Total CDF	2.86E-05	2.43E-05

Notes:

1. Loss of Offsite Power sequences are predominantly Station Blackout sequences.
2. General Transients include Reactor Trip, Loss of Main Feedwater, and Excessive Feedwater.
3. See list of other initiators below.

Other initiators include:

Loss of 4KV Bus 1A2
Loss of 4KV Bus 1B2
Loss of 6.9KV Bus 1A1 As Initiator
Loss of 6.9KV 1B1 As Initiator
Loss of Component Cooling Water (CCW)
Loss of DC Bus 1A
Loss of DC Bus 1B
Loss of Instrument Air
Loss of Intake Cooling Water (ICW)
Loss of 120VAC Instrument Bus 1MA
Loss of 120VAC Instrument Bus 1MB
Loss of 120VAC Instrument Bus 1MC
Loss of 120VAC Instrument Bus 1MD
Seal LOCA Initiating Event (IE) (Loss of CCW Not Related to LOCCWIE or LOICWIE) - All RCPs
Seal LOCA IE (Loss of CCW Not Related to LOCCWIE or LOICWIE) - One RCP
Steamline Break Upstream of SG A Main Steam Isolation Valve (MSIV)
Steamline Break Upstream of SG B MSIV
Steamline Break Downstream of the MSIVs
Spurious Main Steam Isolation Signal
Spurious Safety Injection Actuation Signal
Transient Induced by Power Operated Relief Valve (PORV) Opening with Pressurizer (PRZR) Transmitter (XMTR) Failing Hi PORV 1404
Transient Induced by PORV Opening with PRZR XMTR Failing Hi PORV 1402
Loss of Turbine Cooling Water (TCW)

d. Major differences between the units include the following:

- Unit 2 has larger PORVs, thus only one PORV is required for once-through cooling. This is the main reason why Unit 1 has a larger SGTR CDF than Unit 2.
- Unit 2 has a larger capacity Condensate Storage Tank (CST) than Unit 1. Thus Unit 1 has a slightly higher (but not significant) contribution from long-term decay heat removal related scenarios.
- The Unit 2 shutdown cooling line has one more configuration of an ISLOCA path due to crosstie capability. This increases the ISLOCA frequency for Unit 2.

e. Consistent with what was considered for Level 1 IPE models, uncertainty analysis in the Severe Accident Mitigation Alternatives (SAMA) baseline models considered only two types of uncertainty; parameter value uncertainty and modeling uncertainty. Parameter value uncertainties are typically related to failure rates, frequencies, and unavailabilities. Using Monte Carlo techniques contained in the UNCERT software, parameter value uncertainty was quantified. Each parameter (basic event) in the SAMA baseline cutsets has been assigned a mean and error value using log normal distribution. Through 1000 iterations on a random seed, all parameter value distributions were propagated all the way up to the top level, to finally produce a high confidence mean value frequency. Uncertainty results are often provided in terms of the fifth and ninety-fifth percentiles of the resultant top level

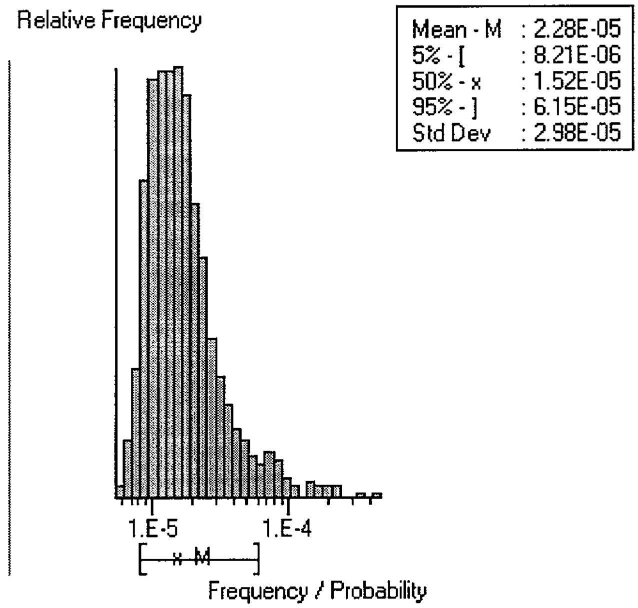

Figure 1-1: Unit 1 Uncertainty Analysis

As shown in Figure 1-1, the Unit 1 fifth and ninety-fifth percentiles for the SAMA CDF of 2.86E-05 are 8.21E-06 and 6.15E-05, respectively, around a mean value of 2.28E-05. The Unit 1 SAMA CDF corresponds to the eighty-fourth (84th) percentile of the distribution.

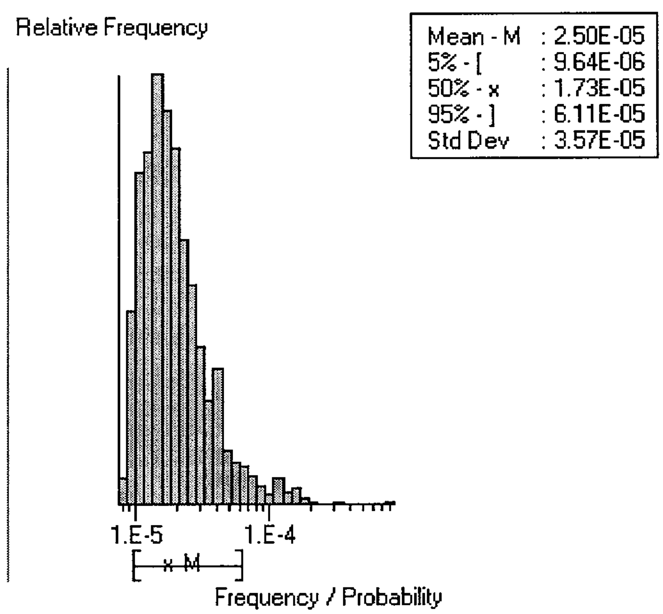

Figure 1-2: Unit 2 Uncertainty Analysis

As shown in Figure 1-2, the Unit 2 fifth and ninety-fifth percentiles of the SAMA CDF of 2.43E-05 are 9.64E-06 and 6.11E-05, respectively, around a mean value of 2.50E-05. The Unit 2 SAMA CDF corresponds to the seventy-third (73rd) percentile of the distribution. Modeling uncertainty is best described as presented in the IPE submittal.

The uncertainty distributions provided above can be considered as representative of the SAMA baseline quantitative result uncertainty. It is worth noting that despite consideration of ISLOCA values in the quantification of the PDSs in each respective unit, analyses have been performed in which additional uncertainties were introduced due to conservative scoping and screening performance.

In order to minimize the effect of inherited uncertainties in the SAMA model and to provide a comprehensive view of the results, sensitivity analyses were also used. Uncertainty and sensitivity analyses are similar in that both strive to evaluate the results arising from the variations in the assumptions, models, and data. However, they differ in approach, scope, and the information they provide.

The uncertainty analysis explicitly quantifies the uncertainties and their relative magnitudes, but requires probability distributions for each of the random variables. The assignment of these distributions often involves as much uncertainty as that to be quantified. Sensitivity analysis is generally more straightforward than uncertainty analysis, requiring only the separate or simultaneous changing of one or more of the inputs. St. Lucie SAMA quantification has used sensitivity analysis whenever possible to offset the accountability of inherited uncertainties in the model.

f.

Table 1-2
Fraction of Population Dose

Containment Release Mode	Unit 1	Unit 2
SGTR (Late and Early)	5.55E-02	1.02E-02
Interfacing Systems LOCAs	5.69E-01	8.07E-01
Early containment failure	1.41E-03	7.09E-04
Late containment failure	3.75E-01	1.82E-01
No containment failure	0.00E-00	0.00E-00
Total	1.00E+00	1.00E+00

The above values were calculated based on Table E.2-3 with a slight change of the exposure risk values for ISLOCA and SGTR to ensure consistency. The ISLOCA exposure risk value is exchanged with that of the SGTR. Although this increases the ISLOCA contribution, there is no impact on the conclusions for SAMAs because there is significant conservatism in the estimated ISLOCA frequency.

The plant-specific Modular Accident Analysis Program (MAAP) results indicated no late containment failure before 24 hours. The large containment failure probability was based on assuming a synthesized failure probability assigned to the containment phenomenological fault trees. The late containment failure contribution is reduced significantly if MAAP results are used directly.

g. a) In the SGTR1 scenario, Auxiliary Feedwater (AFW) is available to the intact steam generator. The transient begins with a single (double-ended) steam generator tube rupture. The reactor scrams at 249 seconds and AFW is actuated at 268 seconds. The MSIVs are closed and the secondary-side pressure in the intact steam generator is reduced to 400 psia by opening the atmospheric dump valves (ADVs). AFW continues until 7.45 hours when the CST is depleted. The intact steam generator dries out at 8.26 hours. With the high pressure safety injection (HPSI) assumed failed, the core uncovers at 11.1 hours and the vessel fails at 15.1 hours. At the vessel failure time, the Reactor Coolant System (RCS) pressure is 1615 psia and the containment pressure is 16 psia. The pressure in the containment rises abruptly to ~30 psia as a result of vessel failure, actuating the fan coolers and the containment spray (CS). The containment pressure reduces due to the cooling provided by the Emergency Core Cooling Systems (ECCS) and the CS. After the vessel failure, most of the debris is predicted by MAAP to reside in the lower compartment.

b) The scenario SGTR2 is initiated by a single steam generator tube rupture. AFW is assumed to be unavailable and the ADVs are opened to reduce the intact steam generator pressure to 400 psia. With assumed no AFW, the intact generator dries out at 0.52 hours. In the absence of HPSI flow, the top of the core uncovers at 2.65 hours leading to vessel failure at 4.99 hours. The containment pressure rise accompanying the vessel failure actuates the fan coolers and the containment spray. The containment pressure remains low and well below the containment failure pressure.

As St. Lucie containments are a wet-cavity type, i.e., for all severe accident scenarios the containment is filled with water, thus reducing significantly the core-concrete interaction. The fraction of carbon monoxide (CO) and hydrogen contribution to containment failure is negligible, as MAAP runs do not indicate containment failure within 24 hours. Late containment failure is caused by not crediting long term decay heat removal, e.g., containment spray, fan coolers, or other ways to flood containment.

Although tellurium (Te) releases appear low, they are reasonable because of the long lead-time to core damage. In addition for most of these scenarios, the longer time after the trip before core damage, the inventories in the damaged steam generators, and the tortuous paths of the intermediate piping provide significant reduction of the radioactive release. For SGTR scenarios, Te releases are contained inside the containment (MAAP runs indicate that Te releases occur at vessel rupture). Since there is significant water in the containment from spray actuation at vessel rupture (wet-cavity), no containment failure is predicted by MAAP runs. Te releases at vessel rupture are not released outside containment.

h. Tables 1-3 and 1-4 below list the key equipment failures and human actions (along with the results of any supporting analyses) that dominate CDF and population dose and that have the greatest potential for reducing the risk of severe accidents (risk reduction worth greater than 1.001). It is noted that the maximum available benefit associated with basic events with risk reduction worth of 1.001 is approximately $1.4K based on internal events only and approximately $2.8K including external events. The reduction worth is slightly higher than the ones used in the submittal, as the turbine-driven AFW pump action under station blackout (SBO) conditions is more conservatively modeled to account for the battery depletion and more strenuous operating conditions.

Table 1-3
Unit 1 Risk Reduction Worth Importance Measures

Reduction Worth	Description
1.314	Small-Small LOCA
1.246	Blackout Crosstie Out of Service (OOS)
1.194	Loss of Grid
1.138	Loss of CCW (Old IE Freq = 9.41E-04) Initiator Flag
1.113	ISLOCA Sequence
1.108	Operator Fails to Realign Power Supply to 125VDC Bus 1AB
1.106	Battery 1A Depleted
1.105	Operating CCF of Motor-driven Pumps
1.097	Operator Fails to Secure RCPs Following Loss of Seal Cooling
1.085	Loss of Main Feedwater But Recoverable
1.084	Pipe Rupture in CCW"N" Header (1-Year Exposure)
1.073	Operator Fails to do Bleed & Feed (Once-Through) Cooling
1.063	N-Header Air-operated Isolation Valves Fail to Close Due to Common Causes
1.049	Large LOCA
1.048	RCP Seal LOCA Prob With Loss of Cooling - Prob from CEOG Eval. (Total For 4 RCPs)
1.047	EDG 1B Fails to Run (FTR) (24-Hour Exposure)
1.046	EDG 1A FTR (24-Hour Exposure)
1.046	Minimum Recirculation (Min Recirc) Line Motor Valves Transfer Closed
1.046	Offsite Power Recovery Case 3: 1 Diesel Fails to Start (FTS) (Or Test/Maintenance) Other DG FTR
1.042	Reactor Trips
1.042	Local Failures Preventing Operation of PORV Train A
1.042	Local Failures Preventing Operation of PORV Train B
1.041	EDG 1A FTS
1.041	EDG 1B FTS
1.039	AFW Pump 1C Train Unavailable Due to Test/Maintenance
1.038	CCF of HPSI Pumps to Run During Injection
1.031	Offsite Power Recovery Case 1: Both Diesels FTS
1.029	Loss of Instrument Air (Old IE Frequency = 9.20E-02)
1.029	Excessive Feedwater
1.028	Loss of DC Bus 1B for Unit 1 (Old IE Freq = 1.073E-03)
1.027	1B DC Bus Fault (1-Year Exposure)
1.026	CCF of EDGs 1A and 1B to Start
1.026	Mechanical Fault Preventing Rod Insertion
1.024	Loss of DC Bus 1A for Unit 1 (Old IE Freq = 1.07E-03)
1.024	1A DC Bus Fault (1-Year Exposure)
1.024	CCF of EDGs 1A and 1B to Run for 24 Hours
1.023	Offsite Power Non-Recovery Case 6:CCF of Diesels to Run
1.023	Minimum Temperature Coefficient (MTC) Not Unfavorable (Unit 1)
1.021	ICW Motor-operated Valves Fail to Close Due to CCFs
1.021	Offsite Power Recovery Case 5: CCF of Diesels to Start
1.019	1B EDG in Test Or Maintenance
1.018	CCF of AFW AC Regulating Valves
1.018	CCW Heat Exchanger (HX) A in Test or Maintenance
1.018	CCW HX B in Test or Maintenance
1.018	EDG 1A in Test or Maintenance
1.018	CCF of HPSI Pumps To Start
1.017	SG 1A Tube Rupture
1.017	SG 1B Tube Rupture

Table 1-3 (continued)
Unit 1 Risk Reduction Worth Importance Measures

Reduction Worth	Description
1.016	AFW Pump 1C FTS
1.016	Modular Event for Header Valves in Flow Path from Mtr Pumps to SG 1A
1.016	4kV AC Breaker 20102 Fails on Demand-A Aux to 1A2
1.016	4kV AC Breaker 20302 Fails to Close (B SU to 1B2)
1.016	'B' CCW Pump (PP) Is Running
1.014	Modular Event for Header Valves in Flow Path from Mtr Pumps to SG 1B
1.014	Offsite Power Non-Recovery Case 4: Both Diesels FTR
1.014	'B' Block Valve Closed W/Power
1.013	1B2 Load Center (LC) Transformer Fault
1.013	Failure of HPSI Pump A to Start
1.013	'A' Block Valve Closed W/Power
1.012	Loss of 4kV Bus 1A2 (Old IE Frequency = 3.94E-04)
1.012	Loss of 4kV Bus 1B2 (Old IE Frequency = 3.94E-04)
1.012	1A Auxiliary Breaker to 1A2 4kV Bus Transfers Open (1-Year Exposure)
1.012	1B Auxiliary Breaker to 1B2 4kV Bus Transfers Open (1-Year Exposure)
1.012	1A2 LC Transformer Fault
1.012	Failure of HPSI Pump B to Start
1.012	Prefilter SF-18-9 Fails to Deliver Flow (1-Year Exposure)
1.012	Afterfilter SF-18-10 Fails to Deliver Flow (1-Year Exposure)
1.012	'A' CCW PP is Running
1.011	Battery 1B Depleted
1.010	Independent Failures of 1A EDG Fuel Oil (FO) Supply System
1.010	Independent Failure of 1B EDG FO Supply System
1.010	1A Startup Transformer Unavailable Due to Maintenance
1.010	1B Startup Transformer Unavailable Due to Maintenance
1.009	Spurious Safety Injection Actuation Signal
1.009	Modular Event for AFW Turbine Pump Trip and Throttle Valve MV-08-3
1.009	Rupture of Pump Suction Line 8-C-56
1.009	CST Ruptures
1.009	4kV AC Breaker 20209 Fails to Open (1A3 From 1A2)
1.009	4kV AC Breaker 20411 Fails to Open (1B3 To 1B2)
1.009	CCF of Unit 1 EDG FO Pumps to Start
1.009	CCF of HPSI Injection Valves to Open
1.008	Loss of Main Feedwater But Not Recoverable
1.008	Spurious Main Steam Isolation Signal
1.008	AFW Pump 1A FTS
1.008	Motor-operated Valve V3654 Transfers Closed During Standby
1.008	Motor-operated Valve V3656 Transfers Closed During Standby
1.008	1A ICW PP Fails to Start During Limiting Condition for Operation (LCO)
1.007	Loss of ICW (Old IE Frequency = 2.68E-04)
1.007	AFW Pump 1B Fails to Start
1.007	CCW HX A Loss of Cooling Capability (0.5-Year Exposure)
1.007	Operator Fails to Restore Pump 1A Following Maintenance
1.007	Operator Fails to Restore Pump 1B Following Maintenance
1.007	Refueling Water Tank (RWT) Rupture
1.007	Unit 2 SDC Fails Following Log Transient (No CST H2O Avail For U1)
1.006	CCF of AFW Pump Discharge Check Valves

Table 1-3 (continued)
Unit 1 Risk Reduction Worth Importance Measures

Reduction Worth	Description
1.006	CCF of CST Discharge Check Valves
1.006	CCF of AFW Header Check Valves
1.006	Failure of AFW Motor Pump Common Suction Valves
1.006	AFW Pump 1C FTR
1.006	AC Breaker 20402 Transfers Open (1B3 4kV to 1B2 LC)
1.006	AC Breaker 40503 Transfers Open (1B3 4kV XF to 1B2 LC)
1.006	CCF of SG Check Valves
1.006	Operator Fails to Realign AB DC Bus (Operator And Hardware)
1.006	Operator Fails to Open Cross-Connect Valves
1.005	AFW Pump 1C Manual Valve V09140 Mispositioned
1.005	AC Breaker 20210 Transfers Open (1A3 4kV To 1A2 LC)
1.005	AC Breaker 40203 Transfers Open (1A3 4kV XF To 1A2 LC)
1.005	HPSI Pump A in Test or Maintenance
1.005	CCF of Turbine Building Supply Fans to Run
1.005	Local Faults in RWT Line
1.005	Offsite Power Recovery Within 9 Hours, Unit 1 CST Depletion
1.004	AFW Pump 1A Manual Valve V09108 Mispositioned
1.004	CCW HX A Loss Of Cooling Capability (72-Hour Exposure)
1.004	CCW HX B Loss Of Cooling Capability (72-Hour Exposure)
1.004	AC Breaker 20309 Transfers Open (1-Year Exposure)
1.004	AC Breaker 20411 Transfers Open (1-Year Exposure)
1.004	FTR - Fail to Align FO System Following Maintenance (Others Tested)
1.004	Local Faults of ECCS Pump A Suction Line from RWT
1.004	Local Faults of ECCS Pump B Suction Line from RWT
1.004	CCF of HPSI Pumps to Run During Recirculation
1.004	Failure of HPSI Pump A to Run During Injection
1.004	Failure of HPSI Pump B to Run During Injection
1.004	CCF of Sump Outlet Motor Valves to Open
1.004	HPSI Pump B In Test or Maintenance
1.004	Low-pressure Safety Injection (LPSI) Injection Valves Fail Open During Hot Leg Injection
1.004	Local Failures of LPSI Common Valves to/from SDC HXS
1.004	MV-21-2 Fails to Close With Safety Injection (SI)
1.004	MV-21-3 Fails to Close With SI
1.004	Operator Fails to Initiate Once-Through Cooling for SGTR
1.004	LOCA in Cold Leg 1A1
1.004	LOCA in Cold Leg 1A2
1.004	LOCA in Cold Leg 1B1
1.004	LOCA in Cold Leg 1B2
1.003	Reactor Trip (PORV Actuated)
1.003	AFW Pump 1B Manual Valve V09124 Mispositioned
1.003	AFW Pump 1A FTR
1.003	AFW Pump 1B FTR
1.003	Modular Event for Not Closing MV-09-11
1.003	Modular Event for Not Closing MV-09-12
1.003	CST Xtie from Unit 2 OOS
1.003	1B CCW PP Breaker Transfers Open (1-Year Exposure)
1.003	Check Valve 14147 Transfers Closed (1-Year Exposure)
1.003	CCW HX A Loss of Cooling Capability (0.5-Year Exposure)

Table 1-3 (continued)
Unit 1 Risk Reduction Worth Importance Measures

Reduction Worth	Description
1.003	1A CCW PP FTS During LCO
1.003	AC Breaker 20109 Transfers Open (1-Year Exposure)
1.003	AC Breaker 20209 Transfers Open (1-Year Exposure)
1.003	FTR – Fail to Align FO System Following Maintenance (Others Tested)
1.003	Motor-operated Valve V2501 Fails to Close Independent Failures
1.003	CCF of The Trip Circuit Breakers
1.003	Operator Fails to Open DG FO Fill Valve Bypass
1.003	Operator Fails to Properly Switch Suction to Refueling Water Tank (RWT) During Anticipated Transient Without Scram (ATWS) or Safety Injection (SI)
1.003	Offsite Power Recovery Case 9:CCF EDG To Start and AFW PP FTS
1.003	'A' Block Valve Closed W/O Power
1.003	'B' Block Valve Closed W/O Power
1.003	'B' ICW PP is Running
1.002	Loss of TCW (Old Freq = 9.41E-04)
1.002	Demand CCF of Motor-driven Pumps
1.002	Modular Event for Header Valves in Flow Path from Turbine Pump to SG 1A
1.002	Modular Event for Header Valves in Flow Path from Turbine Pump to SG 1B
1.002	AFW Pump 1A Train Unavailable Due to Test/Maintenance
1.002	Safety Injection Tank (SIT) 1A1 Injection Path Fails
1.002	SIT 1A2 Injection Path Fails
1.002	SIT 1B1 Injection Path Fails
1.002	SIT 1B2 Injection Path Fails
1.002	1A CCW PP Breaker Transfers Open (1-Year Exposure)
1.002	Check Valve 14143 Transfers Closed (1-Year Exposure)
1.002	'A' CCW Pump FTR (1-Year Exposure)
1.002	'B' CCW Pump FTR (1-Year Exposure)
1.002	AC Breaker 40514 Transfers Open (to motor control center (MCC) 1B5 from LC 1B2)
1.002	1A EDG FO Fill Valve Failures
1.002	1B EDG Fill Valve Failures
1.002	Failure of 125 VDC Feeder Breakers to Operate During Realignment
1.002	Lockout Relay 86GP Fails to Energize
1.002	Local Faults of ECCS Pump A Suction Line from Sump
1.002	Local Faults of ECCS Pump B Suction Line from Sump
1.002	Relief Valve 18119 Spuriously Opens (1-Year Exposure)
1.002	Motor Damper D-9A Unavailable
1.002	Motor Damper D-9B Unavailable
1.002	Failure of LPSI Pump A to Run During Hot Leg Injection
1.002	Failure of LPSI Pump B to Run During Hot Leg Injection
1.002	Local Failures of Normal LPSI Flow Path to Close During SDC
1.002	Motor-operated Valve V3206 Transfers Closed During Standby
1.002	Motor-operated Valve V3207 Transfers Closed During Standby
1.002	Independent Failures of PORV Train A (FTC)
1.002	Independent Failures of PORV Train B
1.002	Motor-operated Valve 1403 Fails to Open
1.002	Motor-operated Valve 1405 Fails to Open
1.002	Air-operated Valve 14-4B Transfers Closed (1-Year Exposure)
1.002	Operator Fails to Diagnose Main Generator Lockout, Reset And Manually Energize Startup Transformer (S/UP)
1.002	Operator Fails to Properly Initiate Hot Leg Injection

Table 1-3 (continued)
Unit 1 Risk Reduction Worth Importance Measures

Reduction Worth	Description
1.002	Failure to Implement Shutdown Cooling (Transient)
1.002	Block Valve MV-1403 Open [to PORV 1402 ("A" AC & DC)]
1.002	Block Valve MV-1405 Open [to PORV 1404 ("B" AC & DC)]
1.001	Small LOCA
1.001	Seal LOCA IE (Loss of CCW Not Related to LOCCWIE or LOICWIE) - All RCPs
1.001	Seal LOCA IE (Loss of CCW Not Related to LOCCWIE or LOICWIE) - One RCP
1.001	Loss of Main Feedwater Due to Feedline Break on SG 1A
1.001	Loss of Main Feedwater Due to Feedline Break on SG 1B
1.001	Steamline Break Downstream of the MSIVs
1.001	CCF of AFW DC Regulating Valves
1.001	Independent Failures In Flow Path to CST
1.001	AFW Pump 1B Train Unavailable Due to Test/Maintenance
1.001	CCF Of SITs Due to Miscalibration of SIT Level Sensors
1.001	CCF Of SITs Due to Miscalibration of SIT Pressure Sensors
1.001	SIT 1A1 in Test or Maintenance
1.001	SIT 1A2 in Test or Maintenance
1.001	SIT 1B1 in Test or Maintenance
1.001	SIT 1B2 in Test or Maintenance
1.001	CCW Pump C Fails to Deliver Flow to HX A
1.001	CCW HX B Plugged (0.5-Year Exposure)
1.001	No Flow Through CCW HX A
1.001	No Flow Through CCW HX B
1.001	CCW Train B Pipe Rupture (1-Year Exposure)
1.001	CCW Train A Pipe Rupture (1-Year Exposure)
1.001	CCW Surge Tank Rupture Fails Train A (1-Year Exposure)
1.001	CCW Surge Tank Rupture Fails Train B (1-Year Exposure)
1.001	1A Battery No Output on Demand
1.001	AC Breaker 40214 Transfers Open
1.001	1A3 4kV AC Breaker Transfers Open (72-Hour Exposure)
1.001	1A3 4kV AC Breaker Transfers Open (72-Hour Exposure)
1.001	1B3 4kV AC Breaker Transfers Open (72-Hour Exposure)
1.001	1B3 4kV AC Breaker Transfers Open (72-Hour Exposure)
1.001	CCF of Unit 1 EDG FO Pumps to Run
1.001	Inverter 1A Unavailable Due to Maintenance
1.001	Battery Charger 1BB Unavailable Due to Maintenance
1.001	Battery Charger 1B Unavailable Due to Maintenance
1.001	Inverter 1B Unavailable Due to Maintenance
1.001	Check Valve 09252 Fails to Open (To 1A SG)
1.001	Check Valve 09294 Fails to Open (To 1B SG)
1.001	Local Faults of HPSI Pump A Min Recirc Line
1.001	Local Faults of HPSI Pump B Min Recirc Line
1.001	CCF of SIS Line Check Valves to Open
1.001	CCF of HPSI Injection Check Valves to Open
1.001	CCF of Min Recirc Line Check Valves to Open
1.001	CCF of HPSI Pump Discharge Check Valves to Open
1.001	CCF of RWT Outlet Check Valves to Open
1.001	Pipe Rupture of HPSI Common Header During Injection
1.001	MV-07-1A Test And Maintenance

Table 1-3 (continued)
Unit 1 Risk Reduction Worth Importance Measures

Reduction Worth	Description
1.001	MV-07-1B Test And Maintenance
1.001	Air Receiver Local Faults (1-Year Exposure)
1.001	Pipe Rupture in Header at Air Receiver Outlet (1-Year Exposure)
1.001	Motor Damper D-8A Unavailable
1.001	Motor Damper D-8B Unavailable
1.001	Motor Damper D-7A Unavailable
1.001	Motor Damper D-7B Unavailable
1.001	Motor Damper D-11A Unavailable
1.001	Motor Damper D-11B Unavailable
1.001	Motor Damper D-12A Unavailable
1.001	Motor Damper D-12B Unavailable
1.001	Motor Damper D-5A Unavailable
1.001	Motor Damper D-5B Unavailable
1.001	Motor Damper D-6A Unavailable
1.001	Motor Damper D-6B Unavailable
1.001	Electrical Equipment Room (EER) Supply Fan HVS-5B Out for Test or Maintenance
1.001	Operator Fails to Restore Pump 1A Following Maintenance
1.001	Operator Fails to Restore Pump 1B Following Maintenance
1.001	CCF of LPSI Pumps to Run During Hot Leg Injection
1.001	Failure of LPSI Pump A to Run During Injection
1.001	Failure of LPSI Pump A to Start During Hot Leg Injection
1.001	Failure of LPSI Pump B to Run During Injection
1.001	Failure of LPSI Pump B to Start During Hot Leg Injection
1.001	Motor-operated Valve MV-03-1A Transfers Open During Standby
1.001	Motor-operated Valve MV-03-1B Transfers Open During Standby
1.001	Manual Valve V18249 Transfers Closed
1.001	CCF of PORV Block Valves
1.001	Air-operated Valve 14-4A Transfers Closed (72-Hour Exposure)
1.001	Air-operated Valve 14-4B Transfers Closed (72-Hour Exposure)
1.001	1A ICW PP Breaker Transfers Open (72-Hour Exposure)
1.001	1B ICW PP Breaker Transfers Open (1-Year Exposure)
1.001	Check Valve 21162 Transfers Closed (72-Hour Exposure)
1.001	Check Valve 21208 Transfers Closed (1-Year Exposure)
1.001	Operator Fails to Realign AFW and Isolate the Faulted SG Following SGTR
1.001	Operator Fails to Properly Switch Suction to RWT
1.001	Adjustment Factor for Recovery
1.001	Operator Fails to Borate During ATWS
1.001	'A' ICW PP Running

Table 1-4
Unit 2 Risk Reduction Worth Importance Measures

Reduction Worth	Description
1.380	Small-Small LOCA
1.302	ISLOCA Event
1.205	Loss of CCW (Old IE Frequency = 9.41E-04) Initiator Flag
1.140	Operator Fails to Secure RCPs Following Loss Of Seal Cooling
1.139	Fail to Use Blackout Crosstie from Unit 1 (W/EQUIP, OP, TIE BKR Failures)
1.124	Loss of Grid
1.101	Pipe Rupture in CCW "N" Header (1-Year Exposure)
1.075	N-Header Air-operated Isolation Valves Fail to Close Due to Common Causes
1.068	RCP Seal LOCA Problem With Loss of Cooling - Problem from CEOG Eval (4 RCPs)
1.061	Operator Fails to Initiate Once-through Cooling
1.046	Large LOCA
1.045	CCF of HPSI Pumps to Run During Injection
1.044	Loss of Main Feedwater But Recoverable
1.043	Operating CCF of Motor-driven Pumps
1.039	2B CCW HX Out for Test or Maintenance
1.038	2A CCW HX Out for Test or Maintenance
1.036	Battery 2A Depleted
1.036	Battery 2B Depleted
1.028	EDG 2A FTR
1.028	EDG 2B FTR
1.025	Reactor Trips
1.025	ICW Motor-Operated Valves Fail to Close Due to CCFs
1.025	Offsite Power Recovery Case 3: 1 EDG FTR/1 EDG FTS
1.024	EDG 2A FTS
1.024	EDG 2B FTS
1.021	CCW HX A Loss of Cooling Capability (0.5-Year Exposure)
1.021	CCF of HPSI Pumps to Start
1.020	AC Breaker 20209 Fails to Open - 2A3 from 2A2 Tie Breaker
1.020	Offsite Power Recovery Case 1: Both Diesels FTS
1.020	'A' CCW PP Is Running
1.018	Failure of HPSI Pump A to Start
1.017	Loss of Instrument Air (Old Freq = 9.20E-02)
1.017	Failure of HPSI Pump B to Start
1.015	CCW HX A Loss of Cooling Capability (0.5-Year Exposure)
1.015	AC Breaker 20411 Fails to Open - 2B3 from 2B2 Tie Breaker
1.015	Conditional Probability that Core Cooling During Injection Will Be Lost Due to Premature Hot Leg Recirculation
1.014	CCF of EDGs 2A And 2B to Start
1.014	'B' CCW PP Is Running
1.013	CCF of EDGs 2A and 2B to Run
1.013	Offsite Power Recovery Case 6: CCF Of Diesels to Run
1.013	Operator Fails to Initiate Hot Leg Injection When Required
1.012	Loss of DC Bus 2B for Unit 2 (Old Freq = 1.073E-03)
1.012	AC Breaker 20102 Fails to Close - S/UP to 2A2 4kV
1.012	AC Breaker 20302 Fails to Close - S/UP to 2B2
1.012	Offsite Power Recovery Case 5: CCF of Diesels to Start
1.011	2C AFW Pump Out for Test or Maintenance
1.011	2A EDG Out for Test or Maintenance

Table 1-4 (continued)
Unit 2 Risk Reduction Worth Importance Measures

Reduction Worth	Description
1.011	2B EDG Out for Test or Maintenance
1.011	Operator Fails to Restore Pump A Following Maintenance
1.011	CCF of HPSI Injection Valves to Open
1.011	Motor-operated Valve V3654 Transfers Closed During Standby
1.011	Motor-operated Valve V3656 Transfers Closed During Standby
1.010	Loss of DC Bus 2A For Unit 2 (Old Freq = 1.073E-03)
1.010	Loss of ICW (Old Freq = 2.68E-04)
1.010	2B DC Bus Fault (1-Year Exposure)
1.010	2A2 LC Transformer Fault
1.010	2B2 LC Transformer Fault
1.010	Operator Fails to Restore Pump B Following Maintenance
1.010	Mechanical Fault Preventing Rod Insertion
1.010	2B CCW PP Fails to Start During LCO
1.009	Loss of 4kV Bus 2A2 (Old IE Frequency = 3.94E-04)
1.009	Loss of 4kV Bus 2B2 (Old IE Frequency = 3.94E-04)
1.009	2A Auxiliary Breaker to 2A2 4kV Bus Transfers Open (1-Year Exposure)
1.009	2B Auxiliary Breaker to 2B2 4kV Bus Transfers Open (1-Year Exposure)
1.009	Local Failures of Common ECCS Pump Train A Min Recirc Valves
1.009	Local Failures of Common ECCS Pump Train B Min Recirc Valves
1.009	Offsite Power Recovery Case 4: Both Diesels FTR
1.008	2A DC Bus Fault (1-Year Exposure)
1.008	2B Startup Transformer Out for Test or Maintenance
1.008	RWT Rupture
1.007	CCF of AFW AC Regulating Valves
1.007	FTR - Fail to Align FO System Following Maintenance (Others Tested)
1.007	Independent Failures of 2B EDGFO Supply System
1.007	2A Startup Transformer Out for Test or Maintenance
1.007	Motor-operated Valve V3523 Transfers Open During Standby
1.007	Motor-operated Valve 3540 Transfers Open During Standby
1.007	Motor-operated Valve V3550 Transfers Open
1.007	Motor-operated Valve V3551 Transfers Open
1.007	Prefilter SF-18-9 Fails to Deliver Flow (1-Year Exposure)
1.007	Afterfilter SF-18-10 Fails to Deliver Flow (1-Year Exposure)
1.006	SG 2A Tube Rupture
1.006	SG 2B Tube Rupture
1.006	AC Breaker 40203 Transfers Open (480V LC 2A2 To MCC 2A5)
1.006	AC Breaker 40520 Transfers Open (For 480V MCC 2B5)
1.006	Independent Failures of 2A EDG FO Supply System
1.006	Local Faults of ECCS Pump A Suction Line from RWT
1.006	Local Faults of ECCS Pump B Suction Line from RWT
1.006	Failure of HPSI Pump A to Run During Injection
1.006	Failure of HPSI Pump B to Run During Injection
1.006	2A HPSI Pump Out for Test or Maintenance
1.006	2B HPSI Pump Out for Test or Maintenance
1.006	MV-21-2 Fails to Close with SI
1.006	MV-21-3 Fails to Close with SI
1.005	Loss of Main Feedwater But Not Recoverable

Table 1-4 (continued)
Unit 2 Risk Reduction Worth Importance Measures

Reduction Worth	Description
1.005	Spurious Main Steam Isolation Signal
1.005	AFW Pump 2C FTS
1.005	CCW HX A Loss of Cooling Capability (72-Hour Exposure)
1.005	CCW HX A Loss of Cooling Capability (72-Hour Exposure)
1.005	AC Breaker 20213 Transfers Open (Power to XF for 480V LC 2A2)
1.005	AC Breaker 20402 Transfers Open (for 480V LC 2B2)
1.005	AC Breaker 40219 Transfers Open (Power to 480V LC 2A2 from XF)
1.005	AC Breaker 40503 Transfers Open (for 480V LC 2B2)
1.005	2A3 4kV AC Breaker Transfers Open (1-Year Exposure)
1.005	2A3 4kV AC Breaker Transfers Open (1-Year Exposure)
1.005	CCF of 2A and 2B EDG FO Pumps to Start
1.005	'A' ICW PP Running
1.005	Moderator Temperature Coefficient Not Unfavorable (Unit 2)
1.004	Rupture of Pump Suction Line 8-C-56
1.004	CST Ruptures
1.004	2A CCW PP Breaker Transfers Open (1-Year Exposure)
1.004	Check Valve 14143 Transfers Closed (1-Year Exposure)
1.004	2B CCW PP FTS During LCO
1.004	CCF of HPSI Pumps to Run During Recirculation
1.004	CCF of Sump Outlet Motor Valves to Open
1.004	Local Faults in RWT Line
1.004	Operator Fails to Recover EDG by Opening DG Fill Valve Bypass
1.004	LOCA in Cold Leg 2A1
1.004	LOCA in Cold Leg 2A2
1.004	LOCA in Cold Leg 2B1
1.004	LOCA in Cold Leg 2B2
1.003	Small LOCA
1.003	CCF of AFW Pump Discharge Check Valves
1.003	CCF of AFW Header Check Valves
1.003	Modular Event for Header Valves in Flow-Path from MTR Pumps to SG 2A
1.003	Modular Event for Header Valves in Flow-Path from MTR Pumps to SG 2B
1.003	SIT 2A1 Injection Path Fails
1.003	SIT 2A2 Injection Path Fails
1.003	SIT 2B1 Injection Path Fails
1.003	SIT 2B2 Injection Path Fails
1.003	2B CCW PP Breaker Transfers Open (1-Year Exposure)
1.003	Check Valve 14147 Transfers Closed (1-Year Exposure)
1.003	'A' CCW Pump FTR (1-Year Exposure)
1.003	Motor-operated Valve MV-14-17 Fails to Close Following SI
1.003	Motor-operated Valve MV-14-18 Fails to Close Following SI
1.003	2B3 4kV AC Breaker Transfers Open (1-Year Exposure)
1.003	2B3 4kV AC Breaker Transfers Open (1–Year Exposure)
1.003	Independent Failures of 2A EDG Day Tank FO Fill Valves
1.003	Independent Failures of 2B EDG Day Tank FO Fill Valves
1.003	CCF of SG Check Valves
1.003	Local Faults of ECCS Pump A Suction Line from Sump
1.003	Motor Damper D-9A Unavailable
1.003	Motor Damper D-9B Unavailable

Table 1-4 (continued)
Unit 2 Risk Reduction Worth Importance Measures

Reduction Worth	Description
1.003	CCF of EER Fans to Run (4 Out Of 4 Fans)
1.003	CCF of Turbine Building Supply Fans to Run
1.003	CCF of the Trip Circuit Breakers
1.003	Independent Failures of PORV Train A
1.003	Independent Failures of PORV Train B
1.003	2B Block Valve (1477) Closed per Tech Specs with Power Available
1.003	A Block Valve Open
1.003	B Block Valve Open
1.003	Spent Fuel Pool Heat Exchangers Aligned to CCW Header A
1.003	Spent Fuel Pool Heat Exchangers Aligned to CCW Header B
1.002	Seal LOCA IE (Loss of CCW Not Related to LOCCWIE or LOICWIE) - All RCPs
1.002	Seal LOCA IE (Loss of CCW Not Related to LOCCWIE or LOICWIE) - One RCP
1.002	Reactor Trip (PORV Actuated)
1.002	Excessive Feedwater
1.002	Loss of TCW (Old Freq = 9.41E-04)
1.002	CCF of AC Solenoid Valves
1.002	AFW Pump 2A FTS
1.002	AFW Pump 2B FTS
1.002	AFW Pump 2C FTR
1.002	CCW HX A Plugged (0.5-Year Exposure)
1.002	CCW HX B Plugged (0.5-Year Exposure)
1.002	'B' CCW Pump FTR (1-Year Exposure)
1.002	FTR - Failure to Properly Align FO System Following Maintenance (Others Tested)
1.002	Local Faults of ECCS Pump B Suction Line from Sump
1.002	Pipe Rupture of HPSI Common Header During Injection
1.002	Motor-operated Valve V2501 Fails To Close Independent Failures
1.002	Air-operated Valve 14-4A Transfers Closed (1-Year Exposure)
1.002	Air-operated Valve 14-4A Transfers Closed (72-Hour Exposure)
1.002	Air-operated Valve 14-4B Transfers Closed (72–Hour Exposure)
1.002	Operator Fails to Properly Switch Suction to RWT
1.002	Operator Fails to Borate During ATWS
1.002	2A Block Valve (1476) Closed per Tech Specs with Power Available
1.001	Steamline Break Downstream of the MSIVs
1.001	AFW Pump 2A Manual Valve V09108 Mispositioned
1.001	AFW Pump 2B Manual Valve V09124 Mispositioned
1.001	AFW Pump 2C Manual Valve V09140 Mispositioned
1.001	Demand CCF of Motor-driven Pumps
1.001	AFW Pump 2A FTR
1.001	AFW Pump 2B FTR
1.001	Modular Event for Header Valves in Flow Path from Turbine Pump To SG 2A
1.001	Modular Event for Header Valves in Flow Path from Turbine Pump To SG 2B
1.001	Manual Valve 12497 Transfers Closed
1.001	CCF of SITs Due to Miscalibration of SIT Level Sensors
1.001	CCF of SITs Due to Miscalibration of SIT Pressure Sensors
1.001	2A1 SIT Out for Test or Maintenance
1.001	2A2 SIT Out for Test or Maintenance
1.001	2B1 SIT Out for Test or Maintenance
1.001	2B2 SIT Out for Test or Maintenance

Table 1-4 (continued)
Unit 2 Risk Reduction Worth Importance Measures

Reduction Worth	Description
1.001	Air-operated Valve 14-1 Transfers Closed (1-Year Exposure)
1.001	Air-operated Valve 14-2 Transfers Closed (1-Year Exposure)
1.001	Air-operated Valve 14-6 Transfers Closed (1-Year Exposure)
1.001	Air-operated Valve 14-7 Transfers Closed (1-Year Exposure)
1.001	CCW HX A Plugged (72-Hour Exposure)
1.001	CCW HX B Plugged (72-Hour Exposure)
1.001	No Flow Through CCW HX A
1.001	No Flow Through CCW HX B
1.001	CCW Pump A FTS
1.001	CCW Pump B FTS
1.001	CCW Train B Pipe Rupture (1-Year Exposure)
1.001	CCW Train A Pipe Rupture (1-Year Exposure)
1.001	CCW Surge Tank Rupture Fails Train A (1-Year Exposure)
1.001	CCW Surge Tank Rupture Fails Train B (1-Year Exposure)
1.001	2A Battery No Output on Demand
1.001	2AB DC Tie Breaker Fails to Operate on Demand (AC Breaker Data Used)
1.001	2AB DC Tie Breaker Fails to Operate on Demand (AC Breaker Data Used)
1.001	2AB DC Tie Breaker Fails to Operate on Demand (AC Breaker Data Used)
1.001	2AB DC Tie Breaker Fails to Operate on Demand (AC Breaker Data Used)
1.001	2A3 4kV AC Breaker Transfers Open (72-Hour Exposure)
1.001	2A3 4kV AC Breaker Transfers Open (72-Hour Exposure)
1.001	2B3 4kV AC Breaker Transfers Open (72-Hour Exposure)
1.001	2B3 4kV AC Breaker Transfers Open (72-Hour Exposure)
1.001	CCF of 2A and 2B EDG FO Pumps to Run
1.001	Main Generator Lockout Relay 86GP Fails to Energize
1.001	2B5 LC Transformer Fault
1.001	2AA Battery Charger Out for Test or Maintenance
1.001	2A Battery Charger Out for Test or Maintenance
1.001	2BB Battery Charger Out for Test or Maintenance
1.001	2B Battery Charger Out for Test or Maintenance
1.001	Local Faults of HPSI Pump A Min Recirc Line
1.001	Local Faults of HPSI Pump B Min Recirc Line
1.001	CCF of Safety Injection System Line Check Valves to Open
1.001	CCF of HPSI/LPSI Common Line Check Valves to Open
1.001	CCF of HPSI Injection Check Valves to Open
1.001	CCF of Min Recirc Line Check Valves to Open
1.001	Failure of HPSI Pump A to Run During Recirculation
1.001	Failure of HPSI Pump B to Run During Recirculation
1.001	CCF of HPSI Pump Discharge Check Valves to Open
1.001	CCF of RWT Outlet Check Valves to Open
1.001	A RWT Outlet Out for Test or Maintenance
1.001	B RWT Outlet Out for Test or Maintenance
1.001	HPSI Min Recirc Header "A" Out for Test or Maintenance
1.001	HPSI Min Recirc Header "B" Out for Test or Maintenance
1.001	Manual Valve V3411 Transfers Closed During Standby
1.001	Manual Valve V3470 Transfers Closed During Standby
1.001	Relief Valve 18119 Spuriously Opens (1-Year Exposure)
1.001	Motor Damper D-8A Unavailable

Table 1-4 (continued)
Unit 2 Risk Reduction Worth Importance Measures

Reduction Worth	Description
1.001	Motor Damper D-8B Unavailable
1.001	Motor Damper D-7A Unavailable
1.001	Motor Damper D-7B Unavailable
1.001	Motor Damper D-12A Unavailable
1.001	Motor Damper D-12B Unavailable
1.001	Motor Damper D-5A Unavailable
1.001	Motor Damper D-5B Unavailable
1.001	Motor Damper D-6A Unavailable
1.001	Motor Damper D-6B Unavailable
1.001	CCF of LPSI Pumps to Run During Injection
1.001	Failure of LPSI Pump A to Run During Injection
1.001	Failure of LPSI Pump A to Start During Injection
1.001	Failure of LPSI Pump B to Run During Injection
1.001	Failure of LPSI Pump B to Start During Injection
1.001	Motor-operated Valve FCV-3301 Transfers Closed During Standby
1.001	Motor-operated Valve FCV-3306 Transfers Closed During Standby
1.001	Motor-operated Valve V3536 Transfers Open During Standby
1.001	Motor-operated Valve V3539 Transfers Open During Standby
1.001	Local Failures Preventing Operation of PORV Train A
1.001	Local Failures Preventing Operation of PORV Train B
1.001	Air-operated Valve 14-4B Transfers Closed (1-Year Exposure)
1.001	2A ICW PP Breaker Transfers Open (1-Year Exposure)
1.001	2B ICW PP Breaker Transfers Open (72-Hour Exposure)
1.001	Check Valve 21162 Transfers Closed (1-Year Exposure)
1.001	Check Valve 21208 Transfers Closed (72-Hour Exposure)
1.001	ICW Pump A FTS
1.001	ICW Pump B FTS
1.001	'A' ICW Pump FTR (1-Year Exposure)
1.001	'B' ICW Pump FTR (72–Hour Exposure)
1.001	Operator Fails to Diagnose Main Generator Lockout, Reset And Manually Energize S/UP
1.001	Operator Fails to Properly Switch Suction to RWT During ATWS
1.001	Operator Fails to Realign Power Supply to 125VDC Bus 2AB
1.001	'A' Block Valve Closed W/Power Available (Not per Tech Specs)
1.001	'B' Block Valve Closed W/Power Available (Not per Tech Specs)
1.001	'B' ICW PP Is Running

QUESTION 2

Risk analyses at other commercial nuclear power plants indicate that external events could be large contributors to core damage and the overall risk to the public. It is recognized that the methods used for the St. Lucie IPEEE do not provide numerical estimates of the CDF contributions from seismic and fire initiators. In view of the fact that the characteristics of the internal and external events scenarios are, in general, considerably different, please demonstrate, through sound PRA arguments and considering the uncertainties in the PSA results, that by doubling the internal events CDF, one can reliably bound the risk of core damage due to all initiators at St. Lucie.

Response to QUESTION 2:

As stated in the Applicant's Environmental Report Operating License Renewal Stage, Appendix E Section E.1.2, to evaluate the potential risks from external events, the cost of implementation of the SAMAs was compared with a benefit value that was twice that calculated. Discussions and conclusions associated with this evaluation are contained in Sections E.1.2.1 through E.1.2.7.

QUESTION 3

In Section 4.15.3, FPL indicates that the top 100 cut sets of the Level 1 PSA update were examined to identify the important contributors to plant risk. What is the total percentage contribution of the 100 cut sets to CDF?

Response to QUESTION 3:

The total percentage contributions of the top 100 cutsets to Level 1 CDFs were estimated to be 55.4% and 67.5% for Unit 1 and Unit 2, respectively.

QUESTION 4

In Section 4.15.3.2, FPL indicates that some SAMAs are more quickly evaluated by examining (through importance measures) the contribution of specific components or human actions to the CDF. Please explain how and what importance measures were utilized in the SAMA identification and elimination processes, and what SAMAs, if any, were identified or eliminated from such processes. If not explicitly used to identify SAMAs, please perform and provide the results of supplementary analyses (based on the latest version of the PSA) confirming that the set of SAMAs considered in the St. Lucie ER address all risk significant contributors identified through plant-specific importance analyses.

Response to QUESTION 4:

As discussed in Section 4.15.3.2 of the St. Lucie Environmental Report, many of the screening evaluations were done using a master PDS cutset for each unit. This was generated for each unit by creating PDSs in the model, which included all sequences. Truncation was set about the same as the sequence runs. This one cutset (one PDSs cutset for each unit) was then used to estimate the risk reduction for a given SAMA. Using the PDSs frequency reduction and the Maximum Available Benefit (MAB - the total benefit if all PDSs frequencies were eliminated) it was possible to estimate the benefits of a wide variety of SAMA items. This technique was not used for estimation for such specific cases as SGTRs and ISLOCAs. Table 4-1 provides a summary of screening evaluation for several SAMAs using PDS cutsets to estimate the maximum benefit associated with a SAMA. This approach is more versatile than using the importance measures alone, as certain SAMAs may involve a few basic events necessitating changing two or more basic event values to zero or changing one basic event to non-zero values. Table 4-2 contains a description of the events listed on Table 4-1.

Table 4-1
Summary of Screening Evaluation used for Several SAMAs using Baseline Cutset Manipulation.

#	SAMA#	Used		CDF w/o "x"		% Reduction		Estimated Cost Benefit		U1 "x"	U2 "x"
		Unit 1	Unit2	Unit 1	Unit 2	Unit 1	Unit 2	Unit 1	Unit 2		
1	4		Case	2.475E-05	1.973E-05	13.3707%	18.6392%	$184,796	$224,062	w/no seal LOCAs (SEALLOCA, SEALLOCA1, RTOP1S1RCP = F). Same as Case 2 where U1=$129,652	w/no seal LOCAs (SEALLOCA, SEALLOCA1, RTOP2S1RCP = F). Same as Case 2 where U2=$145,657
2			✓	2.605E-05	2.127E-05	8.8204%	12.2887%	$121,907	$147,723	RTOP1S1RCP = F	RTOP2S1RCP = F
3			✓	2.630E-05	2.157E-05	7.9454%	11.0515%	$109,813	$132,851	RTOP1S1RCP = 10 lower	RTOP2S1RCP = 10 lower
4			✓	2.511E-05	2.013E-05	12.1106%	16.9897%	$167,381	$204,234	%ZZCCWU1 = F	%ZZCCWU2 = F
5			✓	2.605E-05	2.127E-05	8.8204%	12.2887%	$121,907	$147,723	RTOP1S1RCP = F (same as #2)	RTOP2S1RCP = F (Same as #2)
6			✓	2.596E-05	2.116E-05	9.1355%	12.7423%	$126,261	$153,175	%ZZICWU1 = F and RTOP1S1RCP = F	%ZZICWU2 = F and RTOP2S1RCP = F
7			✓	2.475E-05	1.973E-05	13.3707%	18.6392%	$184,796	$224,062	Seal LOCAs = F (as in #1)	Seal LOCAs = F (as in #1)
8	4		✓	2.474E-05	1.972E-05	13.4057%	18.6804%	$185,280	$224,558	CCW and seals falsed out (#1 plus %ZZCCWU1 = F)	CCW and seals falsed out (#1 plus %ZZCCWU2 = F)
9	55	✓		2.808E-05	2.414E-05	1.7151%	0.4536%	$23,704	$5,453	%ZZT7SIU1 and %ZZT7MSU1 = F	%ZZT7U2 (for MSIS U2) = F
10	80-83, 85, 79, 144	Case		2.762E-05	2.398E-05	3.3252%	1.1134%	$45,957	$13,384	Both SGTR (%ZZRU1A, %ZZRU1B) = F Similar to Case NOSGTR where U1=$111,279	Both SGTR (%ZZRU2A, %ZZRU2B) = F. Similar to Case NOSGTR where U2=$12,640
11	102, 113	✓		2.773E-05	2.403E-05	2.9401%	0.9072%	$40,636	$10,906	mtr pp suct vlvs, pp suct line, cst rupt, cst ck vlvs = F (APPJ18C56, ATKJ1CST, AMM1CSTCV, AMM1MPCSTV)	mtr pp suct vlvs, pp suct line, cst rupt, cst ck vlvs = F (APPJ28C56, ATKJ2CST, AXVK212497)
12		✓	✓	2.857E-05	2.425E-05	0.0000%	0.0000%	$0	$0	NLCD1RPS = F	NLCD2RPS = F
13			✓	2.854E-05	2.421E-05	0.1050%	0.1649%	$1,451	$1,983	RTOP1WBOR = F	RTOP2WBOR = F
14	145	✓		2.857E-05	2.425E-05	0.0000%	0.0000%	$0	$0	RTOP1RLTC = F	RTOP2RLTC = F
15	158	✓		2.845E-05	2.425E-05	0.4200%	0.0000%	$5,805	$0	GMM1SMVCCF & GSMP1EAST = F (no west)	GMM2SMPCCF & GSMP1WEST = F (no east)
16	163	✓		2.335E-05	2.054E-05	18.2709%	15.2990%	$252,522	$183,910	operator actions reduced by 50% (R#RESET, RTOP1[2]MTRIP, R#AFWCMP, R#DC-AB, ZZXCROSST, R#DGFO, RTOP1[2]ROTC, RTOP1[2]TOTC, RTOP1[]2]RLTC, RTOP1[2]S1RCP, RHVA1[2]ELEQ)	operator actions reduced by 50%

Table 4-1 (continued)
Summary of Screening Evaluation used for Several SAMAs using Baseline Cutset Manipulation.

#	SAMA#	Used		CDF w/o "x"		% Reduction		Estimated Cost Benefit		U1 "x"	U2 "x"
		Unit 1	Unit2	Unit 1	Unit 2	Unit 1	Unit 2	Unit 1	Unit 2		
17		✓		2.776E-05	2.385E-05	2.8351%	1.6495%	$39,184	$19,829	%ZZIAU1 = F	%ZZIAU2 = F
18		✓		2.710E-05	2.375E-05	5.1453%	2.0619%	$71,113	$24,786	%ZZDC1A & 1B = F	%ZZDC2A & 1B = F
19		✓		2.789E-05	2.383E-05	2.3801%	1.7320%	$32,896	$20,820	%ZZ4KV1A2 & 1B2	%ZZ4KV2A2 & 1B2
20		✓		2.857E-05	2.425E-05	0.0000%	0.0000%	$0	$0	%ZZ6KV1A1 & 1B1	%ZZ6KV2A1 & 1B1
21	22	✓		2.824E-05	2.419E-05	1.1551%	0.2474%	$15,964	$2,974	Many SDC module events = F	Many SDC module events = F
22	25	✓		2.841E-05	2.410E-05	0.5600%	0.6186%	$7,740	$7,436	IMM1ECCS** for dampers and ITM1ECCEXA[B] = F	IMM2ECCS** for dampers and ITM2ECCEXA[B] = F
23	23, 24, 25, 26,	✓		2.838E-05	2.407E-05	0.6650%	0.7423%	$9,191	$8,923	all the electric room vent sys and RHVA1ELEQ = F	all the electric room vent sys and RHVA2ELEQ = F
24	67	✓		2.705E-05	2.288E-05	5.3203%	5.6495%	$73,531	$67,913	ECBD and ECBR for 4kv = F (ECBD120209, ECBD120411, ECBD120302, ECBD120102, ECBR140503,ECBR140203)	ECBD and ECBR for 4kv = F
25	71, 75, 76	✓		2.393E-05	2.158E-05	16.2408%	11.0103%	$224,464	$132,355	%ZZLOG = F	%ZZLOG = F
26	101	✓		2.530E-05	2.306E-05	11.4456%	4.9072%	$158,189	$58,990	all feed trips = F (not feed line breaks) (%ZZT3AU1,C,E)	all feed trips = F (not feed line breaks)
27	140	✓		2.784E-05	2.400E-05	2.5551%	1.0309%	$35,314	$12,393	Eliminate ATWS (NLCD1RPS, RTOP1MTRIP, NMM1CEDM) = F	NLCD2RPS, RTOP2MTRIP, NMM2CEDM = F
28	148		✓	2.853E-05	2.421E-05	0.1400%	0.1649%	$1,935	$1,983	%ZZT5U1A/B and %ZZT6U1 = F (MSLBs)	%ZZT5U2A/B and %ZZT6U2 = F (MSLBs)
29	149	✓		2.723E-05	2.318E-05	4.6902%	4.4124%	$64,824	$53,041	%ZZAU1 = F	%ZZAU2 = F
30			✓	2.677E-05	2.245E-05	6.3003%	7.4227%	$87,077	$89,228	top 3 HPSI CCFs = F (GMM1FTRCFI, GMM1MPACCF, GMM1HCVCCF)	top 3 HPSI CCFs = F (GMM2FTRCFI, GMM2MPACCF, GMM2HCVCCF)
31	13, 118	✓		2.342E-05	1.936E-05	18.0259%	20.1649%	$249,136	$242,404	Eliminate all HPSI = F (all G*)	Eliminate all HPSI = F (all G*)
32	117, 126		✓	2.693E-05	2.263E-05	5.7403%	6.6804%	$79,336	$80,306	pump CCFs = F (GMM1FTRCFR, GMM1FTRCFI, GMM1MPACCF)	HPSI pump CCFs = F (GMM2FTRCFI, GMM2MPACCF, GMM2FTRCFR)
33	123	Case	.	2.175E-05	1.758E-05	23.8712%	27.5052%	$329,923	$330,641	%ZZS1U1 = F. Same as CASE 3 where U1=$225,316	%ZZS1U2 = F. Same as CASE 3 where U2=216,583
34		✓		2.428E-05	2.051E-05	15.0158%	15.4227%	$207,532	$185,397	Baseline minus cutsets with combination of (%ZZS1U1 and G*)	Baseline minus cutsets with combination of (%ZZS1U2 and G*)
35		✓		2.563E-05	2.325E-05	10.2905%	4.1237%	$142,225	$49,571	ZZBAT1A[B]DEP = F	ZZBAT2A[B]DEP = F

Table 4-1 (continued)
Summary of Screening Evaluation used for Several SAMAs using Baseline Cutset Manipulation.

#	SAMA#	Used		CDF w/o "x"		% Reduction		Estimated Cost Benefit		U1 "x"	U2 "x"
		Unit 1	Unit2	Unit 1	Unit 2	Unit 1	Unit 2	Unit 1	Unit 2		
36	59	✓		2.554E-05	2.325E-05	10.6055%	4.1237%	$146,579	$49,571	ZZBAT1ADEP/[b] = F and R#DC-AB = F	ZZBAT2A[B]DEP = F and R#DC-AB = F
37	146	✓		2.849E-05	2.421E-05	0.2800%	0.1649%	$3,870	$1,983	%ZZT2U1 = F	%ZZT2U2 = F
38	146	✓		2.836E-05	2.407E-05	0.7350%	0.7423%	$10,159	$8,923	OMM1PORVA[Bb] = F with %ZZT2U1=F	OMM2PORVA[B] = F with %ZZT2U2=F
39	152		✓	2.818E-05	2.372E-05	1.3651%	2.1856%	$18,867	$26,273	480 v bkrs ecbr = F (no ecbd) (ECBR140514,...)	480 v bkrs (ecbr*)
40	155	✓		2.836E-05	2.410E-05	0.7350%	0.6186%	$10,159	$7,436	Eliminate All Charging Comp. (i.e., all Ms = F)	Eliminate All Charging Comp. (i.e., all Ms = F)
41		✓		2.042E-05	1.831E-05	28.5264%	24.4948%	$394,263	$294,454	RTOP1S1RCP & ZZXCROSST = F	RTOP2S1RCP & ZZXCROSST = F
42	165	✓		2.323E-05	1.979E-05	18.6909%	18.3918%	$258,327	$221,088	RTOP1S1RCP = F, ZZXCROSST = .05 (hardware)	RTOP2S1RCP = F, ZZXCROSST = .05 (hardware)
43	48	Case		2.857E-05	2.425E-05	0.0000%	0.0000%	$0	$0	Eliminate all CS Comp. (i.e., all Ls falsed) Same as Case 1, where U1=$200,437	Eliminate all CS Comp. (i.e., all Ls falsed). Same as Case 1 where U2=$112,154
44	8, 10, 11, 12, 16		Case	2.727E-05	2.271E-05	4.5502%	6.3505%	$62,889	$76,340	SEALLOCA, SEALLOCA1 = F. Same as Case 4 where U1=$44,343	SEALLOCA, SEALLOCA1 = F. Same as Case 4 where U2=$50,090

TABLE 4-2
EVENT NAMES AND DESCRIPTIONS

EVENT NAME	DESCRIPTION
AMM1CSTCV	CCF of CST Discharge Check Valves
AMM1MPCSTV	Failure of AFW Motor Pump Common Suction Valves
APPJ1[2]8C56	Rupture of Pump Suction Line 8-C-56
ATKJ1[2]CST	CST Ruptures
AXVK212497	Manual Valve 12497 Transfers Closed
ECBD120102	4KV AC Breaker 20102 Fails on Demand – A Aux to 1A2
ECBD120209	4KV AC Breaker 20209 Fails to Open (1A3 to 1A2)
ECBD120302	4KV AC Breaker 20302 Fails to Close (B SU to 1B2)
ECBD120411	4KV AC Breaker 204119 Fails to Open (1B3 to 1B2)
ECBR140203	AC Breaker 40203 Transfers Open (1A3 4KV XF to 1A2 LC)
ECBR140503	AC Breaker 40503 Transfers Open (1B3 4KV XF to 1B2 LC)
ECBR140514	AC Breaker 40514 Transfers Open to MCC from 1B5 from LC 1B2
GMM1[2]FTRCFI	CCF of HPSI Pumps to Run During Injection
GMM1[2]HCVCCF	CCF of HPSI Injection Valves to Open
GMM1[2]MPACCF	CCF of HPSI Pumps to Start
GMM1[2]SMVCCF	CCF of Sump Motor Valves to Open
GSMP1EAST[WEST]	Containment Sump Screen Plugged
IMM[2]1ECCS**	Motor Damper Unavailable
ITM1[2]ECCEXA[B]	ECCS Exhaust Path Unavailable Due to Testing/Maintenance
NLCD1[2]RPS	Logic Circuit RPS Fails to Generator Signal (Rx Trip)
NMM1[2]CEDM	Mechanical Fault Preventing Rod Insertion
OMM1[2]PORVA[B]	Independent Failures of PORV (FTC)
RHVA1[2]ELEQ	Operator Fails to Restore Electrical Equipment Room Fans Following Loss of Power
RTOP1[2]MTRIP	Failure of Manual Reactor Trip Within 1 Minute
RTOP1[2]RLTC	Operator Fails to Implement Shutdown Cooling (SGTR)
RTOP1[2]ROTC	Operator Fails to Initiate Once-through Cooling for SGTR
RTOP1[2]TOTC	Operator Fails to do Bleed and Feed (once-through) Cooling
RTOP1[2]WBOR	Operator Fails to Borate During ATWS
RTOP1S1[2]RCP	Operator Fails to Secure RCPs Following Loss of Seal Cooling
R#AFWCMP	Operator Fails to Actuate AFW Components
R#DC-AB	Operator Fails to Realign AB DC Bus (Operator and Hardware)
R#DGFO	Operator Fails to Open DG FO Fill Valve Bypass
R#RESET	Operator Fails to Diagnose Main Generator Lockout, Reset, and Manually Energize Startup Transformer
SEALLOCA	RCP Seal LOCA Prob With Loss of Cooling – Total of 4 RCPs
SEALLOCA1	RCP Seal LOCA Prob With Loss of Cooling
ZZBAT1[2]A[B]DEP	Battery Depleted
ZZXCROSST	Blackout Crosstie Out of Service
%ZZAU1[2]	Large LOCA
%ZZCCWU1[2]	Loss of CCW
%ZZDC1[2]A[B]	Loss of DC Bus
%ZZLOG	Loss of Grid
%ZZRU1[2]A[B]	SG Tube Rupture
%ZZS1U1[2]	Small-Small LOCA
%ZZT2U1[2]	Reactor Trip (PORV Actuated)
%ZZT3A[C,E]U1	Loss of Main Feedwater, But Recoverable
%ZZT5U1[2]A[B]	Steamline Break Upstream of MSIVs
%ZZT6U1[2]	Steamline Break Downstream of MSIVs
%ZZT7MSU1	Spurious Main Steam Isolation Signal

TABLE 4-2 (continued)
EVENT NAMES AND DESCRIPTIONS

EVENT NAME	DESCRIPTION
%ZZT7SIU1	Spurious Safety Injection Signal
%ZZT7U2	Spurious Main Steam Isolation Signal
%ZZ4KV1[2]A[B]2	Loss of 4KV Bus
%ZZ6KV1[2]A[B]1	Loss of 6.9KV Bus

QUESTION 5

In Appendix E.2, FPL states that for the SECPOP90 code, the county data file was updated to circa 1999 for the nine Florida counties within 50 miles of the plant. Please provide a brief explanation as to how higher economic areas such as resort areas are reflected in the analysis.

Response to QUESTION 5:

The question is addressed in the input to Melcor Accident Consequence Code System MACCS2 (regional economics related) as follows:

> The SECPOP90 code has an included data base of county economic factors derived from the 1990 census and various other government sources dated 1992 to 1994. For the preparation of data for this St. Lucie model the county data file was updated to circa 1999 for the nine Florida counties within 50 miles of the plant. By this means, the site file prepared for St Lucie contained updated values for each county including contributions from resort areas.

QUESTION 6

Based on a review of the SAMAs considered by FPL, the staff requires the following additional information regarding specific SAMAs:

a. SAMA 59 – Provide justification that other alternatives to fuel cells were also considered (such as additional batteries, or backup diesel- or gas-powered generators). Please indicate what the cost estimates and benefits are for such alternatives.

b. SAMA 90 – Provide a description of which penetrations constitute the dominant contributors to ISLOCA risk, and whether some subset of these lines can be tested at an increased frequency without the need for significant hardware modifications, thereby deriving some of the benefit without the large cost of adding or modifying test lines and instrumentation.

c. SAMA 108 – Provide an explanation of the following:

   i. how AFW is controlled manually given a loss of DC power, i.e., without instrumentation.
   ii. how operator action is represented in the PSA, including human error probability values.
   iii. the extent that AFW performance could be improved by this SAMA.

d. SAMAs 71, 75, 76 – FPL states that the CDF contribution of a loss of grid is 16.2%, giving an estimated benefit of $224K. Please describe the accident sequence for a loss of grid, and whether there are lower cost alternatives that could provide a comparable reduction in CDF.

e. SAMA 85 - Provide an explanation of why Unit 1, which has new design steam generators, yields a greater benefit than Unit 2 for the NoSGTR case, especially when FPL indicates that there is not a need for 100% inspection of the Unit 1 tubes.

f. SAMA 118 – FPL indicates that failures of High Pressure Safety Injection (HPSI) contribute 18% to CDF and a total benefit of $249K for elimination of all HPSI failures (see Table 4.15-2, page 4.15-23). Earlier in the same table (see page 4.15-16) for SAMA 13, the estimated benefit from eliminating all HPSI failures is $279K. Details for this particular case (elimination of HPSI) have not been provided. Due to the apparent inconsistency, please provide details (averted costs) commensurate with those provided in Tables E.4-3 and E.4-4.

g. SAMA 145 – Based on the description, no benefit was predicted for RCS depressurization. Please explain the modeling assumptions for this SAMA. If this is due to the fact that depressurization was not modeled in the PSA, please provide an estimate of the benefit if depressurization was modeled.

h. SAMA 160 – The calculated benefit is estimated to be approximately $490K. However, the estimated cost has not been provided. Please provide an estimated cost for this SAMA, and the net value when considering a 7% (basecase) and 3% (sensitivity) discount rate.

Response to QUESTION 6:

a. <u>SAMA 59</u> – This item was discussed with an FPL engineering expert familiar with the St. Lucie batteries. Because of the comprehensive work involved in design, construction, testing, and maintenance involved in installing a new battery, even non-safety related, the cost estimates can quickly escalate to over a half million dollars. A modification of this magnitude would not be cost beneficial.

b. SAMA 90 – The dominant risk contributors are associated with SDC suction line MOVs. These MOVs are locked closed with the handwheel chain locked. Testing at power would require installation of instruments to allow proper and safe testing. Personnel safety and potential challenges to the plant due to additional testing outweigh the risk reduction.

Practical issues preclude on-line periodic testing of the SDC suction MOVs (V3651/V3652 & V3480/V3481). To test the SDC MOVs requires the capability to open one valve at a time in each line in order for the other valve to be exposed to RCS pressure while providing a path behind the valve to a point where leakage can be quantified. The St Lucie Units 1 and 2 design bases and current licensing bases require that two MOVs in series remain closed because they are considered part of the RCS pressure boundary and isolate normal operating RCS pressure from the low pressure SDC piping. The MOVs have an open permissive interlock to prevent opening above 267 psia for Unit 1 and 275psia for Unit 2. On-line periodic testing of these MOVs would remove the double valve protection and thus increase the probability of an ISLOCA.

c. SAMA 108 –

(i.) In the event of an extended loss of offsite power with the EDGs unavailable, it is possible that the batteries would eventually deplete. This should not occur for at least 4 hours after the onset of station blackout conditions. Once DC control power for turbine-driven AFW pump 1C is lost, the turbine governor valve would fail fully open, and the mechanical overspeed trip would trip the pump.

A procedure is available for locally restarting pump 1C in the absence of DC power. Once the pump is restarted, the local operator is instructed to establish a 100 psi differential pressure between the discharge and steam generator pressure. The procedure is intended primarily for situations in which AFW flow could not be controlled from the control room; once the pump was re-started, an operator would control flow locally using MV-09-11 (for steam generator A) and MV-09-12 (for steam generator B).

For this situation, however, there may be no direct indication of AFW flow or steam generator levels. Based on input from operator training instructors and experienced operators, the expected response under these conditions would be to re-start the pump, per the procedure, and then to establish a discharge pressure of about 1200 psig (local pressure indication is available at the pump). This would ensure that the steam generators would be fed, although the flow might be greater than needed. The time it would take to overfill the steam generators to the extent that there might be sufficient water carryover to threaten operation of the AFW pump turbine should be quite long. This would afford ample time to make temporary connections for flow or level indication. There would also be input available from the Technical Support Center and others.

(ii.) Although there is no explicit procedural guidance for controlling flow to the steam generators under these conditions, there is guidance for re-establishing flow from the AFW pump, and it should be possible to control flow in the longer term. The need for this action would not occur until several hours into the event (when the batteries started to be depleted), but it is reasonable to expect that preparatory actions would be initiated well before all DC power was lost. Furthermore, at the reduced decay heat level at this point, it would take a significant period of time to boil off the steam generator inventory. Therefore, the time frame is taken to be intermediate. The need to provide for some means of controlling flow in the longer term makes the action somewhat complex. The working environment could be poor, since operators might be in the position of needing to work with flashlights or other temporary lighting. The failure probability is estimated to be 0.1. Although the importance of the event is increased from the baseline case in which 3.0E-3 is assumed, the cost associated with the SAMA is still greater than the benefit as the risk reduction worth for the operator action is 1.014.

(iii.) It is assumed that the failure probability can be reduced from 0.1 to 0.0. The risk reduction worth is 1.014. If AFW performance is such that the risk due to this scenario is eliminated, the estimated benefit is approximately $20K. It is expected that the cost of improving AFW performance under SBO scenarios involves significant training, more involved procedure changes, or possible hardware changes. This cost is expected to be significantly higher than $100k.

d. SAMAs 71, 75, 76 – The loss of grid-related scenarios are dominated by hardware failures including grid-related failures, EDG failures, or crosstie capabilities. These scenarios are related to seal LOCA scenarios. Lower cost alternatives in reducing the contribution of loss of grid can reduce the CDF slightly, but the benefit would be significantly less than $224K as demonstrated in RCP seal-related SAMAs (e.g., SAMAs 8, 10 and 11).

e. SAMA 85 – Part of the reason is the same as that provided in the response to RAI 1.d. First, Unit 2 has larger PORVs thus only one PORV is required for once-through cooling. This is the main reason why Unit 1 has a larger SGTR CDF than Unit 2. In addition, Unit 2 has a larger capacity CST than Unit 1. Thus Unit 1 has a slightly higher (but not significant) contribution from long-term decay heat removal related scenarios. Although Unit 1 steam generators were installed in 1998, the SGTR frequency used does not explicitly include this consideration.

f. SAMA 118 – For SAMA 13, due to an administrative error, the estimated benefit for eliminating all HPSI failures was incorrectly identified in the Environmental Report. The estimated benefit from eliminating all HPSI failures should be the same as SAMA 118, i.e., $249K and $242K for Unit 1 and Unit 2, respectively. As shown on Table 6-1, this is estimated from the following simple arithmetic, 18% and 20% times the MAB of $1,382,099 and $1,202,105 for Unit 1 and Unit 2, respectively.

Table 6-1
Cost Benefits of SAMAs 13 and 118 (Elimination of HPSI Failures)

	Unit 1		Unit 2	
	Base Case	Zero HPSI Failures	Base Case	Zero HPSI Failures
Offsite Annual Dose (Rems)	15.307	2.759	13.972	2.817
Offsite Annual Property Loss ($)	$42,542	$7,669	$38,571	$7,778
Reduction in CDF	100%	18.026%	100%	20.165%
Averted Onsite Dose	$11,387	$2,053	$9,309	$1,877
Averted Onsite Economic Cost	$583,333	$105,151	$476,909	$96,168
Averted Offsite Population Dose	$329,505	$59,396	$300,754	$60,647
Averted Offsite Economic Cost	$457,875	$82,536	$415,133	$83,711
Total Benefit	$1,382,099	$249,136	$1,202,105	$242,403

g. SAMA 145 – RCS depressurization is covered in the EOP for SGTR and LOCAs. The benefit of improving the RCS depressurization for SGTR as indicated in the negligible contribution of RTOP1RLTC (Operator Fails to Implement Shutdown Cooling –SGTR) CDF for the SGTR scenarios. The RCS depressurization for LOCAs is not credited in the model, as a more detailed thermal hydraulic analysis to determine the cooldown criteria may be required to ensure correct timing requirements. If RCS depressurization is modeled, the CDF contribution from LOCAs (mainly small-small LOCAs and transient-induced small-small LOCAs, e.g., SBO seal LOCAs) would become smaller. The RCS cooldown and depressurization (which are already in the EOPs), if included in the model, would also reduce the already low risk from SBO scenarios. Assuming that the RCS depressurization would fail with a probability of 0.01, any additional improvement in the RCS depressurization (assuming that failure probability would be 0) would have a maximum benefit of approximately $5K (excluding external events) or $10K (including external events).

h. SAMA 160 – In the St. Lucie Environmental Report, Tables E.3-1 and 4.15-2 describe SAMA 160, which deals with the removal of fission products following an ISLOCA. No credit is assumed in the PSA model for mitigation of ISLOCAs outside containment. A plant-specific detailed estimate of cost is not necessary as features similar to those described for this SAMA (i.e., charcoal filters) already exist at St. Lucie. The St. Lucie Units 1 and 2 License Renewal Application, Subsection 2.3.3.15 provides a description of the plant ventilation systems, including ECCS areas and Shield Building Ventilation.

QUESTION 7

NUREG/CR-0184 states that the impact of a three-percent (3%) discount rate should be assessed as a sensitivity analysis. FPL indicates that this was done, but that no SAMAs became cost-beneficial as a result. Please provide the results of the sensitivity analysis for each of the 6 cost cases evaluated in Appendix E.4.

Response to QUESTION 7:

A 3% discount rate was used to estimate the MAB (see Tables 7-1 and 7-2). The description of the cases cited in Tables 7-1 and 7-2 are included in the Environmental Report Appendix E Section E-4. The following conservatisms not included in the model are expected to reduce the benefits by a factor of two or more so that the increase due to a 3% discount will not change the conclusions:

- Severe Accident Mitigation Guidelines (SAMGs) are not explicitly included in the model
- RCS depressurization is not fully credited in the model
- Level 2 and 3 operator actions having a longer time to complete but not credited in the model.

Table 7-1
Impact of 3% Discount Rate on SAMA Results for Unit 1

	BaseLine	NoISLOCA	NoSGTR	Case1-CS	Case2-seal	Case3 - SSL	Case4
Offsite Annual Dose (Rems)	15.307	11.363	13.244	11.947	14.357	13.643	14.982
Offsite Annual Property Loss ($)	$42,542	$32,421	$38,535	$30,771	$39,870	$37,834	$41,628
Reduction in CDF	100%	9.69%	3.99%	0.24%	13.52%	23.34%	4.62%
Averted Onsite Dose	$18,516	$1,795	$739	$44	$2,504	$4,322	$856
Averted Onsite Economic Cost	$748,295	$72,545	$29,855	$1,759	$101,194	$174,673	$34,608
Averted Offsite Population Dose	$460,436	$118,632	$62,070	$101,091	$28,601	$50,055	$9,783
Averted Offsite Economic Cost	$639,815	$152,216	$60,270	$177,038	$40,185	$70,805	$13,745
Total Benefit	**$1,867,062**	**$345,188**	**$152,934**	**$279,931**	**$172,484**	**$299,856**	**$58,993**

Table 7-2
Impact of 3% Discount Rate on SAMA Results for Unit 2

	BaseLine	NoISLOCA	NoSGTR	Case1-CS	Case2-seal	Case3 - SSL	Case4
Offsite Annual Dose (Rems)	13.972	6.329	13.806	12.094	12.902	12.370	13.603
Offsite Annual Property Loss ($)	$38,571	$18,957	$38,201	$31,999	$35,564	$34,036	$37,531
Reduction in CDF	100%	22.98%	1.05%	0.21%	18.56%	27.41%	6.37%
Averted Onsite Dose	$15,138	$3,479	$159	$31	$2,810	$4,150	$964
Averted Onsite Economic Cost	$1,103,560	$253,599	$11,579	$2,279	$204,874	$302,521	$70,259
Averted Offsite Population Dose	$420,261	$229,902	$4,978	$56,480	$32,175	$48,195	$11,105
Averted Offsite Economic Cost	$580,088	$294,984	$5,556	$98,836	$45,227	$68,198	$15,633
Total Benefit	**$1,627,264**	**$668,951**	**$17,112**	**$156,610**	**$193,787**	**$288,250**	**$66,651**

QUESTION 8:

In Appendix E.1, FPL indicates that a design change was implemented at Unit 2 that increased the calculated probability of ISLOCA while reducing the probability of pressure locking of the shutdown cooling isolation valves (which would prevent the use of shutdown cooling), and that this change was risk neutral or positive overall. In Appendix E.4, FPL develops the NoISLOCA case to determine the benefit to be obtained from reducing ISLOCAs. In Table E.4-4, the total benefit is estimated to be approximately $490K for Unit 2 (approximately twice the benefit as in Unit 1). In light of this sizeable benefit, please explain how the design change has affected this case, i.e., what is the increase in CDF and risk due to the design change, and why a further design change to reduce ISLOCA risk is not justified for Unit 2.

Response to QUESTION 8:

The main design change was aimed at improving shutdown cooling. The configuration, however, increases the number of paths of ISLOCA. It is believed that the ISLOCA estimates for Unit 2 have conservatisms and the increase is outweighed by the improvement in the shutdown cooling. The ISLOCA model is conservative in the following areas: no credit is taken for the additional valve in the flow path, no credit is taken for the pressure relief and ultimate strength of the low pressure piping and the dose reduction of the auxiliary building. These conservatisms are qualitatively considered, but not quantified.

QUESTION 9

A licensee for another CE plant identified the following six SAMAs as potentially cost beneficial. These SAMAs or equivalents were not addressed in the SAMA analyses submitted for the St. Lucie Plant.

a. Modify procedures to conserve or prolong the inventory in the refueling water storage tank during SGTRs, including procedures to refill the tank
b. Add accumulators or implement training on refueling water storage tank bubblers and recirculation valves in order to prevent a premature recirculation actuation signal and ECCS pump damage due to inadequate net positive suction head
c. Add capability for steam generator level indication during a station blackout using a portable 120V AC generator
d. Provide a 480V AC power supply to open the power-operated relief valve and reduce the potential for temperature-induced SGTR, and high pressure melt ejection
e. Add capability to flash the field on the emergency diesel generator (using a portable generator) to enhance station blackout event recovery
f. Add manual steam relief capability and associated procedures to provide an alternate cooldown path to increase the capability of the plant to cope with ISLOCAs, SGTRs, and long-term station blackouts

Please provide a brief explanation regarding the applicability/feasibility of these SAMAs for the St. Lucie plant. Also, SAMA 21 in the St. Lucie evaluation ("Create procedure and operator training enhancements in support-system failure sequences, with emphasis on anticipating problems and coping") was deemed cost beneficial at the other CE plant; however, FPL eliminated it from further consideration because the SAMA had been implemented or the intent was met. Please explain how this SAMA was implemented or how the intent of this SAMA was met.

Response to QUESTION 9:

a. The St. Lucie EOP network already addresses this scenario. Therefore this SAMA is not appropriate for St. Lucie. The procedures are: EOP–03, Loss of Coolant Accident, EOP-04, Generator Tube Rupture, with the Safety Status Check Sheet (SSCS), AP 0010120, Conduct Of Operations, and EOP-15, Functional Recovery. Use of these procedures will result in the initiation of "actions to makeup to the RWT."

b. St. Lucie RWT level indication and, therefore, the Recirculation Actuation System (RAS) does not depend on instrument air. In addition, manual actuation is a backup to the automatic actuation. This SAMA is not applicable based on the St. Lucie plant configuration and the PSA model.

c,d,e. These SAMAs are related to SBO or loss of offsite power scenarios. St. Lucie Plant has 4 EDGs and crosstie capability. These features make these scenarios less important for the St. Lucie PSA. These SAMAs are not applicable based on the St. Lucie plant configuration and PSA model.

f. One aspect of this SAMA is related to SBO or loss of offsite power scenarios. St. Lucie plant has 4 EDGs and crosstie capability. These features make these scenarios less important for St. Lucie. For ISLOCAs, and SGTRs, the St. Lucie PSA model does not indicate that additional relief capability would reduce risk. This SAMA is not cost-beneficial based on the St. Lucie PSA model.

SAMA 21 of the St. Lucie evaluation considers the training and procedures available in the plant such that the intent of the SAMA is already addressed by these features. The safety improvement evaluated at the other CE plant may be different as St. Lucie plant has certain features that are not in the other CE plant.

These features (e.g., automatic RAS and additional EDGs) may make certain procedures less onerous. Improving procedures and training is a continuing process as enhancements are identified. The PSA model does not indicate significant cost-benefit if these procedural refinements or enhancements were to be modeled in more detail.