ATTACHMENT C SEVERE ACCIDENT MITIGATION ALTERNATIVES (SAMAS)

ATTACHMENT C-1 BEAVER VALLEY UNIT 1 SAMA ANALYSIS

EXECUTIVE SUMMARY

This report provides an analysis of the Severe Accident Mitigation Alternatives (SAMAs) that were identified for consideration by the Beaver Valley Power Station Unit 1. This analysis was conducted on a cost/benefit basis. The benefit results are contained in Section 4 of this report. Candidate SAMAs that do not have benefit evaluations have been eliminated from further consideration for any of the following reasons:

- The cost is considered excessive compared with benefits.
- The improvement is not applicable to Beaver Valley Unit 1.
- The improvement has already been implemented at Beaver Valley Unit 1 or the intent of the improvement is met for Beaver Valley Unit 1.

After eliminating a portion of the SAMAs for the preceding reasons, the remaining SAMAs are evaluated from a cost-benefit perspective. In general, the analysis approach examines the SAMAs from a bounding analysis approach to determine whether the expected cost would exceed a conservative approximation of the actual expected benefit. In most cases, therefore, a detailed risk evaluation in which a specific modification/procedure change is evaluated would indicate a smaller benefit than calculated in this evaluation.

Major insights from this benefit evaluation process included the following:

- If all core damage risk is eliminated, then the benefit in dollars over 20 years is $5,120,856.
- The largest contributors to the total benefit estimate are from offsite dose savings and offsite property costs.
- A large number of SAMAs had already been addressed by existing plant features, modifications to improve the plant, existing procedures, or procedure changes to enhance human performance.

BVPS Unit 1 Potentially Cost Beneficial SAMAs

BV1 SAMA Number	Potential Improvement	Discussion	Additional Discussion
164	Modify emergency procedures to isolate a faulted SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	
167	Increase the seismic ruggedness of the emergency 125V DC battery block walls	Reduce failure of batteries due to seismic induced failure of battery room block walls.	
168	Install fire barriers for HVAC fans in the cable spreading room	Eliminate failure of fire propagating from one fan to another.	
187	Increase seismic ruggedness of the ERF Substation batteries. This applies to the battery rack only and not the entire structure.	Increased reliability of the ERF diesel following seismic events	
189	Provide Diesel backed power for the fuel pool purification pumps and valves used for makeup to the RWST.	Increased availability of the RWST during loss of offsite power and station blackout events.	BVPS plans to implement this SAMA through alternate mitigation strategies that provide portable pumps that can be used for RWST makeup by the end of 2007.

1 INTRODUCTION

1.1 PURPOSE

The purpose of the analysis is to identify SAMA candidates at the Beaver Valley Power Station Unit 1 that have the potential to reduce severe accident risk and to determine whether implementation of the individual SAMA candidate would be cost beneficial. NRC license renewal environmental regulations require SAMA evaluation.

1.2 REQUIREMENTS

- 10 CFR 51.53(c)(3)(ii)(L)
    - The environmental report must contain a consideration of alternatives to mitigate severe accidents "…if the staff has not previously considered severe accident mitigation alternatives for the applicant's plant in an environmental impact statement or related supplement or in an environment assessment..."
- 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 76
    - "…The probability weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to ground water, and societal and economic impacts from severe accidents are small for all plants. However, alternatives to mitigate severe accidents must be considered for all plants that have not considered such alternatives…."

2 METHOD

The SAMA analysis approach applied in the Beaver Valley assessment consists of the following steps.

- **Determine Severe Accident Risk**

    Level 1 and 2 Probabilistic Risk Assessment (PRA) Model
    The Beaver Valley Unit 1 PRA model (Section 3.1 – 3.2) was used as input to the consolidated Beaver Valley Unit 1/2 Level 3 PRA analysis (Section 3.4).

    The PRA results include the risk from internal and external events. The external hazards evaluated in the PRA are internal fires and seismic events only. High winds and tornadoes, external floods, and transportation and nearby facility accidents are not included in the results since they were screened from the IPEEE submittal because their individual CDF fell below the cutoff criteria of 1.0E-06 per year.

Level 3 PRA Analysis
The Level 1 and 2 PRA output and site-specific meteorology, demographic, land use, and emergency response data was used as input for the consolidated Beaver Valley Unit 1/2 Level 3 PRA (Section 3). This combined model was used to estimate the severe accident risk i.e., off-site dose and economic impacts of a severe accident.

- **Determine Cost of Severe Accident Risk / Maximum Benefit**

The NRC regulatory analysis techniques to estimate the cost of severe accident risk were used throughout this analysis. In this step these techniques were used to estimate the maximum benefit that a SAMA could achieve if it eliminated all risk i.e., the maximum benefit (Section 4).

- **SAMA Identification**

In this step potential SAMA candidates (plant enhancements that reduce the likelihood of core damage and/or reduce releases from containment) were identified by Beaver Valley Unit 1 (BVPS-1) plant staff, from the PRA model, Individual Plant Examination (IPE) and IPE – External Events (IPEEE) recommendations, and industry documentation (Section 5). This process included consideration of the PRA importance analysis because it has been demonstrated by past SAMA analyses that SAMA candidates are not likely to prove cost-beneficial if they only mitigate the consequences of events that present a low risk to the plant.

- **Preliminary Screening (Phase I SAMA Analysis)**

Because many of the SAMA candidates identified in the previous step are from the industry, it was necessary to screen out SAMA candidates that were not applicable to the BVPS-1 design, candidates that had already been implemented or whose benefits have been achieved at the plant using other means, and candidates whose roughly estimated cost exceeded the maximum benefit. Additionally, PRA insights (specifically, importance measures) were used directly to screen SAMA candidates that did not address significant contributors to risk in this phase (Section 6).

- **Final Screening (Phase II SAMA Analysis)**

In this step of the analysis the benefit of severe accident risk reduction was estimated for each of the remaining SAMA candidates and compared to an implementation cost estimate to determine net cost-benefit (Section 7). The benefit associated with each SAMA was determined by the reduction in severe accident risk from the baseline derived by modifying the plant model to represent the plant after implementing the candidate. In general, the modeling approach used was a bounding approach to first determine a bounding value of the benefit. If this benefit was determined to be smaller that the expected cost, no further modeling detail was necessary. If the benefit was found to be greater that the estimated cost, the modeling was refined to remove conservatism in the modeling and a less conservative benefit was determined for comparison with the estimated cost.

Similarly, the initial cost estimate used in this analysis was the input from the expert panel (plant staff familiar with design, construction, operation, training and maintenance) meeting. All costs associated with a SAMA were considered, including design, engineering, safety analysis, installation, and long-term maintenance, calibrations, training, etc. If the estimated cost was found to be close to the estimated benefit, then first the benefit evaluation was refined to remove conservatism and if the estimated cost and benefit were still close, then the cost estimate was refined to assure that both the benefit calculation and the cost estimate are sufficiently accurate to justify further decision making based upon the estimates.

- **Sensitivity Analysis**

The next step in the SAMA analysis process involved evaluation on the impact of changes in SAMA analysis assumptions and uncertainties on the cost-benefit analysis (Section 8).

- **Identify Conclusions**

The final step involved summarizing the results and conclusions (Section 9).

3 SEVERE ACCIDENT RISK

The BVPS PRA models describe the results of the first two levels of the BVPS probabilistic risk assessment for the plant's two units. These levels are defined as follows: Level 1 determines CDFs based on system analyses and human reliability assessments; Level 2 evaluates the impact of severe accident phenomena on radiological releases and quantifies the condition of the containment and the characteristics of the release of fission products to the environment. The BVPS models use PRA techniques to:

- Develop an understanding of severe accident behavior;
- Understand the most likely severe accident consequences;
- Gain a quantitative understanding of the overall probabilities of core damage and fission product releases; and

- Evaluate hardware and procedure changes to assess the overall probabilities of core damage and fission product releases.

The Unit 1 and Unit 2 PRAs were initiated in response to Generic Letter 88-20, which resulted in IPE and IPE for External Events (IPEEE) analyses. The current model for each Unit (BV1REV4 for Unit 1 and BV2REV4 for Unit 2) is a consolidated Level 1 / Level 2 model including both internal and external initiating events (i.e., consolidates IPE and IPEEE studies into a single, Unit-specific PRA model) for power operation. This means that severe accident sequences have been developed from internal and external initiated events, including internal floods, internal fires, and seismic events.

The PRA models used in this analysis to calculate severe accident risk due to Unit 1 are described in this section. The Unit 1 Level 1 PRA model (internal and external), the Unit 1 Level 2 PRA model, Unit 1 PRA model review history, and the Unit 1 Level 3 PRA model, are described in Section 3.1, 3.2 and 3.4.

3.1 LEVEL 1 PRA MODEL

3.1.1 Internal Events

3.1.1.1 Description of Level 1 Internal Events PRA Model

The US Nuclear Regulatory Commission (NRC) issued Generic Letter No. 88-20, in December 1988, which requested each plant to perform an individual plant examination of internal events (IPE) to identify any vulnerabilities. In response, Duquesne Light Company (DLC) submitted an IPE report (Reference 2) using a probabilistic risk assessment (PRA) approach for Beaver Valley Power Station Unit 1 (BVPS-1) in October 1992 that examined risk from internal events, including internal flooding.

The updated PRA model, used to determine CDF, is the BV1REV4 model. This model contains the Level 1 PRA model for internal initiating events. The software used in the update process was RISKMAN. A Level 1 PRA presents the risk (that is, what can go wrong and what is the likelihood?) associated with core damage. For the updated PRA, core damage is defined as the uncovery and heatup of the reactor core to the point where prolonged cladding oxidation and severe fuel damage is anticipated. This condition is expected whenever the core exit temperatures exceed 1,200°F and the core peak nodal temperatures exceed 1,800°F.

The Beaver Valley Unit 1 internal events CDF is calculated to be <u>3.98E-06 /year</u>. The fault tree method of quantification is binary decision diagram quantification, which provides an exact solution for split fraction values. The event tree quantification was calculated using a truncation cutoff frequency of 1.0E-14, or more than 8 orders of magnitude below the baseline CDF. The results of the CDF quantification of risk from internal events is summarized in Table 3.1.1.1-1 (Initiating Event Contribution to internal core damage), Table 3.1.1.1-2 (Basic Event Importance) and Table 3.1.1.1-3 (Component Importance). Contribution to internal events CDF from ATWS and SBO is presented below for information purposes.

	Contribution to Internal CDF (/year)
ATWS	3.85E-07
SBO	2.62E-07

The original PRA model (IPE submittal) was based on the BVPS-1 plant configuration circa 1988 and was calculated using a plant specific database that included equipment failures and maintenance history from January 1, 1980 until the end of 1988. The original PRA model was then updated for the IPEEE submittal (Reference 3) based on the BVPS-1 plant configuration at the end of 1993. The results presented in this report are based on an updated PRA model (BV1REV4), which has a “freeze date” of April 20, 2006 for the plant configuration, and a “freeze date” of December 31, 2005 for component failure data and initiating event data. Equipment unavailabilities were based on Maintenance Rule availability history from November 1, 1998 to December 31, 2005. This updated PRA model was also revised to include modeling enhancements.

Table 3.1.1.1-1: BV1REV4 Dominant Initiating Event Contribution to Internal Core Damage					
Initiator	**Description**	**Initiating Event Frequency**	**Contribution to Internal CDF**	**Percent of Internal CDF***	**Cumulative Percent of Internal CDF**
AOX	Loss of Emergency 4160V AC Orange	1.78E-02	6.64E-07	17%	17%
BPX	Loss of Emergency 4160V AC Purple	1.78E-02	6.43E-07	16%	33%
WCX	Loss of All River Water Systems	1.31E-06	2.66E-07	7%	40%
ELOCA	Excessive Loss of Coolant Accident	2.66E-07	2.66E-07	7%	46%
RTRIP	Reactor Trip	7.47E-01	2.18E-07	5%	52%
DPX	Loss of Emergency 125V DC Purple	4.80E-03	1.99E-07	5%	57%
TTRIP	Turbine Trip	6.52E-01	1.91E-07	5%	62%
PLMFWA	Partial Loss of Main Feedwater - ATWS	5.00E-01	1.55E-07	4%	66%
PLMFW	Partial Loss of Main Feedwater	5.00E-01	1.50E-07	4%	70%
LOSPE	Loss of Offsite Power - Extreme Weather Related	2.24E-03	1.44E-07	4%	74%
DOX	Loss of Emergency 125V DC Orange	4.80E-03	1.10E-07	3%	76%
IMSIV	Closure of One MSIV	2.00E-01	7.94E-08	2%	78%
IMSIVA	Closure of One MSIV - ATWS	2.00E-01	6.06E-08	1%	80%
EXFW	Excessive Feedwater Flow	1.65E-01	5.14E-08	1%	81%
EXFWA	Excessive Feedwater Flow - ATWS	1.65E-01	5.13E-08	1%	82%
TLMFW	Total Loss of Main Feedwater	4.14E-02	3.71E-08	1%	83%
SLOCN	Small LOCA, Nonisolable	2.66E-03	3.66E-08	1%	84%
MLOCAA	Medium Loss of Coolant Accident in Loop A	2.02E-05	3.39E-08	1%	85%
MLOCAB	Medium Loss of Coolant Accident in Loop B	2.02E-05	3.39E-08	1%	86%
MLOCAC	Medium Loss of Coolant Accident in Loop C	2.02E-05	3.39E-08	1%	87%
LCV	Loss of Condenser Vacuum	1.16E-01	3.36E-08	1%	88%
ISI	Inadvertent Safety Injection Initiation	8.12E-02	3.23E-08	1%	88%
ISIA	Inadvertent Safety Injection Initiation - ATWS	8.12E-02	2.47E-08	1%	89%
LOPF	Loss of Primary Flow	8.10E-02	2.32E-08	1%	90%
LOSPG	Loss of Offsite Power - Grid Centered	1.34E-02	2.21E-08	1%	90%
* Percentages are rounded off the whole numbers.					

Table 3.1.1.1-2 BV1REV4 Top 10 Basic Events by Risk Reduction Worth (Internal Events)

Rank	Basic Event Name	Basic Event Description	RRW*	Associated SAMA
1	HVXCRW200	RW-200 Manual Valve Transfers Closed	1.15E+00	Cooling Water SAMAs
2	CBXO480VUS18N1	480V Breaker 480VUS-1-8N1 Transfers Open	1.10E+00	AC PWR SAMAs
3	CBXO480VUS19P1	480V Breaker 480VUS-1-9P1 Transfers Open	1.10E+00	AC PWR SAMAs
4	XXFRACTIONRODS	Fraction of RT Failures Caused by Control Rods Failing to Insert	1.08E+00	ATWS SAMAs
5	PPRPRW3	Common Header Pipe Break	1.08E+00	Cooling Water SAMAs
6	FRCTRIF05	Fraction of Time There is Insufficient Relief with 0 PORVs Blocked	1.08E+00	SAMA 156
7	DGSREEEG1	Diesel Generator EE-EG-1 Fails to Run After 1st Hour	1.06E+00	AC PWR SAMAs
8	DGSREEEG2	Diesel Generator EE-EG-2 Fails to Run After 1st Hour	1.05E+00	AC PWR SAMAs
9	BSORDCSWBD2	Failure of 125V DC Bus 2 DC-SWBD-2 During 24 hr Mission Time	1.05E+00	DC PWR SAMAs
10	BSOR480VUS18N	480V Bus 480VUS-1-8-N Fails During Operation	1.05E+00	AC PWR SAMAs

* The Risk Reduction Worth (RRW) is defined by the following Fussell-Vesley (FV) relationship:
RRW = 1 / (1 - FV)

Table 3.1.1.1-3 BV1REV4 Top 10 Components by Risk Reduction Worth (Internal Events)				
Rank	**Component Name**	**Component Description**	**RRW***	**Associated SAMA**
1	RW-200	Common River Water Header Isolation Valve	1.15E+00	Cooling Water SAMAs
2	EE-EG-1	No. 1 Emergency Diesel Generator	1.12E+00	AC PWR SAMAs
3	EE-EG-2	No. 2 Emergency Diesel Generator	1.11E+00	AC PWR SAMAs
4	480VUS-1-8N1	Incoming Supply Breaker From 4KVS-1AE-1E12	1.10E+00	AC PWR SAMAs
5	480VUS-1-9P1	Incoming Supply Breaker From 4KVS-1DF-1F12	1.10E+00	AC PWR SAMAs
6	RW-PIPE	River Water System Pipe	1.08E+00	Cooling Water SAMAs
7	DC-SWBD-2	125 VDC Switchboard #2	1.05E+00	DC PWR SAMAs
8	480VUS-1-8-N	480V Substation 1-8 Emergency Bus 1N	1.05E+00	AC PWR SAMAs
9	4KVS-1AE	4160 Emergency AC Bus 1AE	1.05E+00	AC PWR SAMAs
10	480VUS-1-9-P	480V Substation 1-9 Emergency Bus 1P	1.05E+00	AC PWR SAMAs
* The Risk Reduction Worth (RRW) is defined by the following Fussell-Vesley (FV) relationship: RRW = 1 / (1 - FV)				

3.1.1.2 Level 1 PRA Model Changes since IPE Submittal

The major Level 1 changes incorporated into each revision of the Beaver Valley Unit 1 PRA model are discussed below. The individual affect on CDF by incorporating each of these changes has not been analyzed. However, each change is listed in order of expected importance, with the top change being the most important.

BVPS-1 PRA Model History							
PRA Model	**Rev.**	**Date**	**Internal**		**Total**		**Comments**
			CDF	**LERF**	**CDF**	**LERF**	
BV1	0	10/01/92	2.14E-04	1.06E-05	-	-	IPE Model
BV1REV1	1	06/30/95	1.17E-04	5.85E-06	1.44E-04	7.11E-06	IPEEE model
BV1REV2	2	06/30/98	6.24E-05	7.06E-07	8.50E-05	9.14E-07	Integrated Level 1 and Level 2 models
BV1REV3	3	09/05/03	7.45E-06	9.98E-07	2.34E-05	9.99E-07	NEI 00-02 Peer Review A/B F&Os addressed
BV1REV4	4	06/02/06	3.98E-06	7.41E-08	1.95E-05	7.54E-08	RSG/ACC/EPU Model

<u>Beaver Valley Unit 1 Revision 0</u>

This revision represents the base case IPE quantification and resulted in a core damage frequency of <u>2.14E-04 / year</u> for internal events.

<u>Beaver Valley Unit 1 Revision 1</u>

This revision represents the updated IPE PRA model that served as the baseline risk model for the IPEEE.

Changes made include implementation of IPE vulnerability enhancements, slight changes to the top event models to reflect plant modifications performed through 1993, and plant-specific data updates of component failures and maintenance through June 1993. These changes resulted in an internal events core damage frequency of <u>1.17E-04 / year</u>.

Model changes associated with the vulnerability enhancements made to this revision consisted of the following two model modifications:

- Adding a new top event to credit the installation of the 4160V station crosstie from the Unit 2 emergency diesel generators to the 1AE emergency bus.

- Making revisions to the primary pressure relief top event for Anticipated Transient Without Scram (ATWS) events by taking full credit for the capacity of the three pressurizer PORVs to reduce the unfavorable exposure time (UET).

Beaver Valley Unit 1 Revision 2

Beaver Valley Unit 1 Revision 2 was made with the following model modifications. The changes resulted in an internal events core damage frequency of 6.24E-05 / year.

- The updated model gave credit for the operators to depressurize the RCS during small break LOCAs, so that a low head safety injection pump can provide makeup and core cooling, given the failure of the high head safety injection system. The CDF definition was also changed so that both core exit temperatures exceeded 1,200°F and the core peak nodal temperatures exceeded 1,800°F must be present.
- The revised frequency included consideration of the station cross-tie connecting the 4KV normal buses of Beaver Valley Units 1 and 2. This cross-tie capability was credited in the IPEEE submittal, but only for the 1AE emergency bus. The revised cross-tie model permitted credit for the Unit 2 emergency diesel generators, if available, to power either Unit 1 emergency AC bus 1AE or 1DF, given the failure of both Unit 1 emergency diesel generators and a loss of offsite power.
- If a loss of the AC Orange Train (assumed to be the operating train in the PRA model) is the initiating event, the 125 DC Purple bus will get a demand signal to auto start the standby components immediately. If the AC Purple Train is unavailable, the battery charger will supply the load; if the battery charger fails the battery will supply the load for the following two hours. This is considered to provide sufficient time to start standby components before the battery drains. Therefore, the model in this revision now provided credit for either the DC bus 2 charger or batteries to supply the load to start standby components, whenever a loss of AC power to the normally operating equipment is the initiating event.

Beaver Valley Unit 1 Revision 3

Beaver Valley Unit 1 Revision 3 was made with the following model modifications and incorporated the PRA Peer Review resolutions to the category A and B Facts and Observations (F&Os). The changes resulted in an internal events core damage frequency of 7.45E-06 / year.

- The updated model used the latest industry methodology for determining Reactor Coolant Pump (RCP) seal LOCAs. This methodology is based on WCAP-15603, Rev. 0 (Reference 21); however, it is slightly modified to account for the NRC's preliminary comments reviewing WCAP-15603. This modification used a number 1 seal popping-and-binding failure probability P(PB1) of 0.025 (which is the same as the Brookhaven Model) instead of 0.0125. With this new RCP seal LOCA model there is a 78-percent probability that the seal leakage will not exceed 21 gpm per RCP during the loss of all seal cooling condition, which accounts for the installed high-temperature O-rings on all three RCPs.

- The revised RCP Seal LOCA frequency also included plant specific thermal-hydraulic analyses performed with Modular Accident Analysis Program (MAAP) 4.0.4, which now accounted for sequences that do not go to core melt during a 48-hour period, given that Auxiliary Feedwater (AFW) or Dedicated AFW is available, as non-core damage sequences. These analyses were performed for both Station Blackout and loss of all river water scenarios. RCP Seal LOCA sequences that uncover the core before 48 hours, but after 30 hours, now used an electric power recovery factor based on the probability of not recovering offsite power before core damage occurs using the Plant-Centered LOSP Recovery lognormal distribution reported in NUREG/CR-5496 (Reference 8) and the median probability of not recovering at least one emergency diesel generator at times greater than 24-hours (if available for recovery).
- The High Head Safety Injection (HHSI) / charging pump ventilation support system was removed from this PRA model update based upon FENOC analysis 8700-DMC-1559, Rev. 0, "BVPS-1 Charging Pump Cubicle Heatup Following a Design Basis Accident (DBA) and Loss of Ventilation, PRA Analysis" (Reference 9). The results of this analysis show that when crediting buoyancy driven air flow from the pump cubicles and using a more realistic 1-month post DBA runout condition in place of the assumed Environmental Qualification (EQ) 6-month post DBA runout condition, the HHSI/charging pumps would continue to operate for a 24-hour period following a complete loss of all ventilation.
- The initiating events data was based on WCAP-15210 (Reference 10) to develop a generic prior and then Bayesian updated using Beaver Valley Unit 1 actual plant experience. Based on the PRA Peer Review comments, Unit 1 actual plant experience from January 1, 1980 though December 31, 2001 was used for the Bayesian update. Additionally, LOCA initiating event frequencies were now based on the interim LOCA frequencies taken from Table 4.1 of the "Technical Work to Support Possible Rulemaking for a Risk-Informed Alternative to 10CFR50.46/GDC 35" , to account for aging-related failure mechanisms.
- The Electric Power Recovery model, updated with the latest system models, credited more scenarios with recovery of the fast bus transfer breakers, emergency diesel generators, and offsite grid.
- In response to PRA Peer Review comments on the ATWS model, operator credit to perform emergency boration was now given even if earlier actions to manually trip the reactor or insert control rods fail.
- The reactor trip breaker failure rates were now based on NUREG/CR-5500 (Reference 22) and then Bayesian updated using a more detailed analysis of Beaver Valley Unit 1 actual plant experience.
- Motor operated valve failure rates were based on NUREG-1715 (Reference 23) to develop a generic prior and then Bayesian updated using Beaver Valley Unit 1 actual plant experience.
- The SSPS split fractions were now based on a CAFTA model using BVPS-2 plant specific components and Westinghouse generic failure rates. This model was

developed as part of the risk-informed application for the Unit 2 Slave Relay Surveillance Test Interval Extension. These split fraction values were considered to be a better estimate than the previous Unit 1 PRA models, which were based on the Diablo Canyon SSPS model.
- The concerns of the PRA Peer Review on the interfacing system LOCA initiating event frequency were addressed using the latest industry information from NUREG/CR-5102 and NUREG/CR-5603. Additionally, the Monte Carlo value from this revised model was used for the initiating event frequency.
- Each of the emergency diesel generators have 2.5% of unavailability associated with them based on the then current INPO/WANO industry guidelines, which provides more hours for future on-line maintenance.

<u>Beaver Valley Unit 1 Revision 4</u>

Beaver Valley Unit 1 Revision 4 was made with the following model modifications and incorporated the Extended Power Uprate (EPU) to 2900 MWth, Replacement Steam Generators (RSG), and Atmospheric Containment Conversion (ACC). The changes resulted in an internal events core damage frequency of <u>3.98E-06 / year</u>.

- The SGTR initiating event frequencies are now based on the replacement Model 54F (Alloy 690) steam generators installed during 1R17, which have a lower rupture frequency (6.96E-04 per SG per year) as opposed to the original Model 51 steam generators (1.48E-03 per SG per year). These replacement SGTR initiating event frequencies were calculated in 8700-DMC-1647,"Initiating Event Steam Generator Tube Rupture Frequency for Beaver Valley Unit 1 Usage in PRA Modeling" (Reference 11)
- The third train of station instrument air, consisting of an auto start, diesel driven station air compressor is included in the PRA model. This system also provides an air supply to the containment instrument air system.
- The emergency diesel generator unavailability is once again based on historical BVPS unavailability, since extended on-line maintenance beyond 72-hours would require the availability of an additional AC power source (i.e., spare diesel generator) capable of supplying safe shutdown loads during a station blackout, per Licensing Amendments 1A-268 & 2A-150. Therefore, it is believed that there is a low probability that the extended AOT would ever be implemented.
- The initiating events data is based on Westinghouse WCAP-15210, Revision 1, "Transient Initiated Event Operating History Database for U.S. Westinghouse NSSS Plants (1987 – 1997)" to develop a generic prior and then Bayesian updated using Beaver Valley Unit 1 actual plant experience from January 1, 1980 though December 31, 2005.
- The methodology used to calculate the human error probabilities (HEP) was changed from the Success Likelihood Index Methodology (SLIM) to the EPRI HRA Calculator. These new HEPs also used operator action timings based on plant specific MAAP thermal hydraulic analysis that included the EPU, RSG, and ACC.

- The updated model uses the latest NRC accepted methodology for determining RCP Seal LOCAs. This methodology is based on Westinghouse's WCAP-15603, Revision 1-A, (Reference 7). The use of this revision differs from the previous PRA model in that the 57 gpm RCP seal LOCA probability was reassigned to the 182 gpm seal LOCA, and now has a zero probability. This is due to the NRC review of the WCAP, which concluded that given the failure of the second stage seal the third stage seal failure probability is unity, since it is not designed to handle more than the normal operating pressure differential of a few psid. However, with this new RCP Seal LOCA model there is now a 79% probability that the seal leakage will not exceed 21 gpm per RCP during the loss of all seal cooling condition, which accounts for the installed high-temperature o-rings on all three RCPs.
- The revised RCP Seal LOCA frequency also includes plant specific thermal hydraulic analyses performed with MAAP DBA and accounts for full EPU conditions. Sequences that do not go to core melt during a 48 hour period, given that AFW or Dedicated AFW is available, are not counted as core damage sequences, since it is believed that an alternate source of power could be provided within this time frame to maintain the reactor in a safe stable state. These analyses were performed for both Station Blackout and loss of all river water scenarios.
- The loss of offsite power (LOSP) initiating event is now broken down into five separate initiators; (1) plant-centered, (2) grid-centered, (3) switchyard centered, (4) severe weather related, and (5) extreme weather related. The basis for these initiating event frequencies comes from NUREG/CR-INEEL/EXT-04-02326, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1986 – 2003 (Draft)," (Reference 12) that were Bayesian updated with BVPS-1 plant specific data.
- The offsite power restoration probability curves used in the electric power recovery analyses are also based on NUREG/CR-INEEL/EXT-04-02326 potential bus restoration data using a composite curve. The composite curve is a frequency-weighted average of the four individual LOSP category curves (it excluded the extreme weather related data), which was Bayesian updated with plant-specific LOSP frequencies. The electric power recovery factors are not credited for extreme weather related LOSP initiators.
- The consequential loss of offsite power probability following reactor trips was updated based on more recent industry and expert opinion data sources.

3.1.2 External Events

For external events, the development of a list of possible scenarios is similar to that for internal events. Because of this, the models for external events can take advantage of much of the work completed for internal events. Rather than develop new event trees for external events, use is made of the most appropriate event trees developed earlier for internal events. Only the changes needed to account for the unique aspects of the external events are required.

3.1.2.1 Internal Fires

The fire analysis employs a scenario-based approach that meets the intent of NUREG-1407 to systematically identify fire and smoke hazards and their associated risk impact to BVPS-1. The analysis was divided into two phases: (1) a spatial interactions analysis phase and (2) a detailed analysis phase. In the spatial interactions analysis phase, one or more fire and smoke hazard scenarios were developed for each plant location that can potentially initiate a plant transient or affect the ability of the plant to mitigate an accident. The scenarios developed in this phase are called location scenarios. Conservative assumptions were made in the assessment of scenario impacts to screen out location scenarios that have a relatively insignificant impact on plant safety.

In the detailed analysis phase, detailed scenarios were developed for the location scenarios that survived the spatial interactions analysis screening. One or several frequency reduction factors (geometry factor, severity factor, fire nonsuppression factor, and nonrecovery factor) were assessed for each detailed scenario. As each frequency reduction factor was assessed, conservatism introduced in the earlier phase was reduced and the complexity of the analysis progressively increased. Whenever one or more reduction factors led to the conclusion that the risk associated with a detailed scenario was relatively insignificant, the analysis for that detailed scenario would be halted. Each detailed scenario was evaluated iteratively until the scenario was considered to be relatively risk insignificant or all frequency reduction factors were assessed. The plant vulnerabilities to fire and smoke hazards were assessed by aggregating the risk impact of the subscenarios. The frequency of fire and smoke hazard-initiated core damage sequences was used as a measure of the potential for plant vulnerabilities.

The containment performance in response to fire threats, Fire Risk Scoping Study (FRSS) issues, and other special safety issues were also evaluated. Risk management options could then be identified to reduce the risk impact associated with these scenarios.

The major steps of the Beaver Valley Fire Individual Plant Examination for External Events (IPEEE) are summarized as follows:

- Phase 1: Spatial Interactions Analysis

  1. Information Gathering and Data Collection
  2. Preliminary Screening and Identification of Important Locations

3. Development of Location Scenarios
4. Quantitative Screening

- Phase 2: Detailed Analysis

5. Development and Analysis of Detailed Scenarios
6. Sensitivity/Uncertainty Analysis
7. Containment Performance Evaluation
8. Resolution of the FRSS and Other Safety Issues

The BVPS-1 Fire PRA has not been explicitly updated since the IPEEE. However, as the Fire sequences are dependent on internal events modeling, the Fire sequences have implicitly been partially updated with updates to the internal events models. Additionally, screened-out detailed scenarios that were considered to be relatively risk insignificant in the IPEEE, but close to the threshold (1.17E-07/yr at Unit 1), were reanalyzed and included in subsequent PRA model revisions. Results of the Fire PRA for BVPS-1 are provided in the following Table 3.1.2.1-1

Table 3.1.2.1-1: Fire PRA Results

	BVPS-1 PRA Model
Current Fire CDF (/year)	3.67E-06
IPEEE Fire CDF (/year)	1.75E-05

Beaver Valley Unit 1 IPEEE Information

From the IPEEE, there are no readily apparent vulnerabilities to fire events at BVPS-1. The discussion that follows highlights the most significant contributors, in terms of how the plant might be changed to reduce the already acceptable risk.

Two general areas for improvement are considered; i.e., the equipment impacts that may result from fires in key areas, and the plant response to the most risk significant postulated fires. The current controls in place at Beaver Valley are judged to be adequate to limit the frequency of fires from internal plant sources.

The extent of equipment impacted by a fire depends on the originating location and to a large extent the amount and arrangement of cables within the rooms affected. For many of the key fire subscenarios identified, the equipment impacts are limited. For example, both trains of river water may be disabled by the fire, but there may be no other plant impacts. For such scenarios, repositioning of equipment or the rerouting of selected cables may be effective at reducing the risks of core damage.

Possible changes that might affect the frequency of the top five fire subscenarios are presented in Table 3.1.2.1-2 (extracted from Table 7-1 of the BVPS-1 IPEEE) for BVPS-1. The frequency assessment of the key scenarios is consistent with the analysis in

Appendix R (Reference 14), in that, for the key scenarios, it accounts for operator recovery actions that may have been credited in the Appendix R analysis.

Table 3.1.2.1-2: BVPS-1 IPEEE Model/Design Enhancements

CDF Key Contributor	Model or Design Enhancement	IPEEE CDF Importance		Percent of Total CDF **	Status
		Percent of CDF	Risk Reduction Worth *		
Emergency 125V DC Battery Room Block Walls	Reevaluate block wall fragility, reinforce block walls, or shield batteries.	67.3 (Seismic)	0.5962 (Seismic)	4.2	The block walls have been evaluated and found satisfactory in accordance with both USI A-46 and IEB 80-11. This along with a low contribution to total CDF warrants no further action.
CV-3 Fire	Reroute River Water pump power cable.	24.4 (Fire)	0.7560 (Fire)	3.0	The low contribution to total CDF warrants no further action.
CS-1 Fire (SW Corner)	Refine Emergency Switchgear room heatup analysis to provide additional time margin.	15.3 (Fire)	0.8470 (Fire)	1.9	The low contribution to total CDF warrants no further action.
PA-1E Fire	Reroute CCR Pump or HHSI suction MOV cables.	13.7 (Fire)	0.9189 (Fire)	1.7	The low contribution to total CDF warrants no further action.
CS-1 Fire (NE Corner)	Reroute River Water or Auxiliary RW pump power and control cables.	11.5 (Fire)	0.8846 (Fire)	1.4	The low contribution to total CDF warrants no further action.
NS-1 Fire (South Wall)	Reroute River Water pump control cables or Auxiliary RW pump power cables.	7.9 (Fire)	0.9210 (Fire)	1.0	The low contribution to total CDF warrants no further action.

Notes: * The Risk Reduction Worth is the factor decrease in CDF that would be realized if the failure probability of the affected system were decreased to 0.0 (i.e., guaranteed success). ** Total CDF includes both internal and external events.

3.1.2.2 Seismic Events

A PRA was performed for internal initiating events on the Beaver Valley Power Station in satisfaction of the IPE requirements. To assess the risk contribution and significance of seismic-initiated events to the total plant risk, it was determined that the PRA method would also be used for the seismic analysis to meet the requirements of the IPEEE.

Beaver Valley selected the Seismic PRA option over the seismic margins option for the following reasons:

- With the existing PRAs for internal events that were developed to support the IPE and the decision to extend the PRA for all of the external events within the IPEEE scope, all severe accident issues are addressed within the context of an integrated PRA model that consistently treats all internal and external initiating events. This model rigorously accounts for all accident sequences resulting from any combination of internal and external events. The resulting risk information provided from this integrated approach was viewed as more useful to DLC management to make decisions about allocating resources to manage the risks of severe accidents.

- With the ability to link the Level 1 and Level 2 event trees as demonstrated in the IPE, the selected PRA approach was found to provide a more rigorous examination of potential containment vulnerabilities and seismic/systems interactions impacting containment effectiveness than was possible using the seismic margins approach.

The methodology selected is consistent with PRAs performed with the procedures contained in NUREG/CR-2300. In general, the methodology used in the analysis consisted of the following main steps:

- Seismic Hazard Analysis**.** Determination of the frequency of various potential peak ground accelerations (PGA) at the site, and an assessment of the likelihood of landslides and soil liquefaction.

- Fragility Analysis**.** Determination of the conditional failure probability of risk-related plant structures and components at peak ground accelerations.

- Plant Logic Analysis. Development of logic models that evaluate the potential structure and component failure scenarios. The models include seismic-induced failures that may initiate an accident scenario and may directly disable components or systems needed to successfully terminate the scenario. The models also include potential failures and unavailabilities of components due to nonseismic causes.

- Level 1/2 Integration. The linking of Level 1 seismic event trees with the Level 2 containment event tree for an integrated Level 2 PRA of seismic events and seismic/system integrations to examine containment effectiveness.

- Assembly and Quantification. Assembly of the seismic hazard, component fragilities and nonseismic unavailabilities, and plant logic models, including model quantification to obtain point estimates for core damage, plant damage state, release category, and scenario frequencies that result from seismic-initiated events.

- Uncertainty Quantification. Calculation of probability distributions for category (Level 2 results) and core damage frequencies (Level 1 results) that can be combined with the results from other initiating events.

The BVPS-1 Seismic PRA has not been explicitly updated since the IPEEE. However, as the seismic sequences are dependent on internal events modeling, the seismic sequences have implicitly been partially updated with updates to the internal events models. Additionally, the BVPS-1 Revision 3 PRA model revised the component seismic fragilities based on the September 10, 1999 response to the Nuclear Regulatory Commission's IPEEE Request for Additional Information, dated July 8, 1999. This response noted that following a review of the analysis, the BVPS median capacities for those structures and equipment for which the seismic fragilities were directly calculated were overestimated by approximately 36%. Incorporating these new component fragilities resulted in the modeling of additional Seismic Top Events, as well as, increasing the failure probabilities. Results of the Seismic PRA for BVPS-1 are provided in the following Table 3.1.2.2-1

Table 3.1.2.2-1: Seismic PRA Results

	BVPS-1 PRA Model
Current Seismic CDF (/year)	1.19E-05
IPEEE Seismic CDF (/year)	9.07E-06 (Original) 1.29E-05 (RAI Revised)

Beaver Valley Unit 1 IPEEE Seismic Information

The IPEEE concluded that there are no readily apparent vulnerabilities to seismic events at BVPS-1. The discussion that follows highlights the most significant contributors, in terms of how the plant might be changed to reduce the already acceptable risk.

Two general areas for improvement were considered; i.e., the plant response to seismic-initiated failures and the equipment seismic fragilities.

For the top 50 highest frequency core damage sequences in the original IPEEE submittal, the conditional frequencies of core damage given the seismic initiating event and failures directly attributable to it are all 1.0. In the large majority of these sequences, either the seismic failures result in a station blackout, a loss of all DC control power, or the loss of all river water. In some of the top sequences, there may be two or more failures, which if they occurred alone, would each result in core damage. Therefore, it is concluded that options to improve the plant response to seismic events would not be effective in limiting risk. This conclusion was also reached in the IPEEE RAI response.

Although the offsite power grid and the 125V DC ERF Substation battery are assessed as having the weakest fragility curves of those modeled, the most risk significant seismic fragility is that of the 125V DC battery room block walls. Failure of these walls is assumed to result in the loss of both sets of emergency DC control power and eventual core damage. Enhancements to these block walls were considered and are presented in Table 3.1.2-1 (extracted from Table 7-1 of the BVPS-1 IPEEE) for BVPS-1.

Beaver Valley Unit 1 USI A-45 Resolution

Resolution of the external events portion of Unresolved Safety Issue A-45 was subsumed into the IPEEE requirements that allow plant-specific evaluation of the safety adequacy of decay heat removal systems.

The Beaver Valley Unit 1 PRA results provide indications of the importance of systems that directly perform the decay heat removal function. The IPEEE indicates the importance of systems that perform the decay heat removal function. Five classes of systems were considered: main feedwater, auxiliary feedwater, bleed and feed cooling, steam generator depressurization for RCS cooldown, and closed loop residual heat removal. Importance is measured by the percentage of core damage frequency attributable to sequences that involve failure of the indicated split fraction. The importance measures are not additive because more than one of the ranked split fractions may, and often do, fail in the same sequence.

Two event tree top events are used to represent the main feedwater system. Top Event “MF” represents the hardware failure modes under normal operations and Top Event “OF” represents the operator action to realign main feedwater after a plant trip, given that auxiliary feedwater fails. The most important main feedwater system failures occur in sequences for which main feedwater is lost due to the seismically caused loss of its support systems, i.e., split fraction MFF.

Top Event “AF” represents the auxiliary feedwater system. The most important auxiliary feedwater system failures are due to loss of all support systems to the motor-driven and turbine-driven pumps.

Feed and bleed cooling is modeled by four separate event tree top events: Top Event “HH” for the HHSI pumps, Top Event “HC” for the cold leg injection flow path, Top Event “VL” for the path from the RWST, and Top Event “OB” that models the bleed path via the pressurizer. Because of the credit taken for realigning the electric-driven main feedwater pumps, the Beaver Valley Unit 1 design minimizes the frequency of sequences involving failure of AFW and bleed and feed cooling, relative to other PWRs. Three of these four top events (“HC”, “HH”, and “VL”) are also used to model high head safety injection in the event of a small LOCA.

Top Event “CD” models the action to depressurize the steam generators in sequences where it is desirable to cool down and depressurize the RCS. Steam generator depressurization helps to limit RCS leakage during a station blackout or a steam generator tube rupture with a stuck-open secondary side valve. As can be seen from the percentage of contribution listed in IPEEE Table 3-17, such failures are relatively unimportant to the core damage frequency.

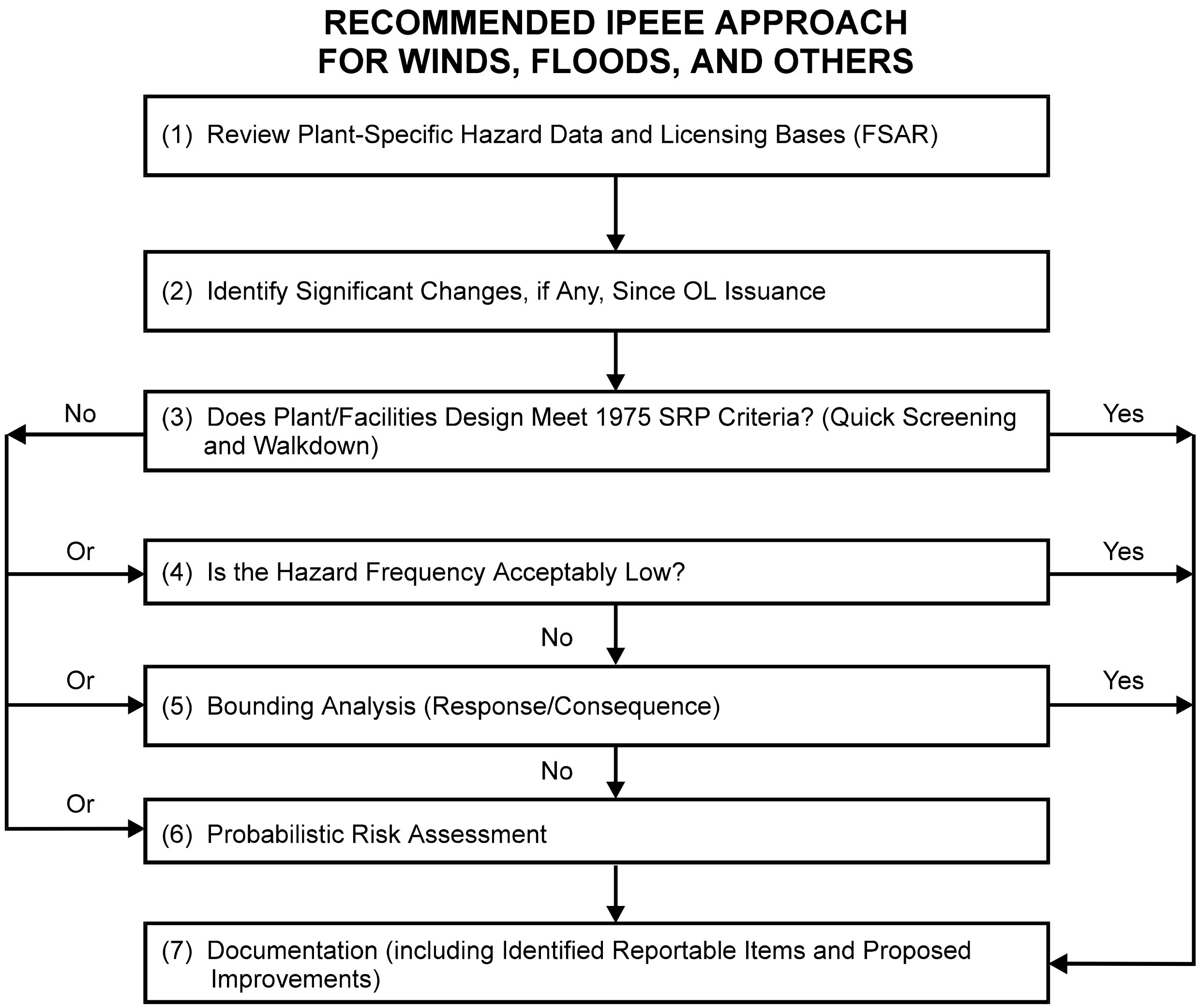
Finally, the importance of cooling via the residual heat removal system is also indicated in IPEEE Table 3-17. The RHR system plays only a minor role in the determination of the core melt frequency. By design, this system is tripped off on a Phase B containment isolation signal. No sequences greater than 7.0E-09 per year involved failure of the RHR.

In summary, no particular vulnerabilities of the Beaver Valley Unit 1 systems that are used to perform decay heat removal have been identified. The majority of the seismic core damage frequency at Beaver Valley Unit 1 comes from loss of emergency AC and DC power caused by the seismic initiating event. No discernible frequency comes from failures of decay heat removal.

3.1.2.3 Other External Events

NUREG-1407 recommends a screening type approach, as shown in Figure 3.1.2.3-1 (taken from Figure 5-1 of NUREG-1407). The general methodology used at BVPS-1 follows the approach recommended by NUREG-1407 and consists of the following steps:

- Establishing a List of Plant-Specific Other External Events
- Progressive Screening
- Walkdown
- Documentation



Note: Steps 4 through 6 are optional.

Figure 3.1.2.3-1: NUREG-1407 Screening Approach

Based on the results in the BVPS-1 IPEEE, it was concluded that the plant structures at the site are well designed to withstand the high wind associated hazards and that no potential vulnerability was identified.

Since the plant and facilities design meets the 1975 SRP criteria, and that there are no existing plant changes that could affect the plant hazard data or the licensing bases with respect to flooding, the core damage frequency due to external flooding was estimated to be less than 1.0E-06 per year for BVPS-1.

The NRC staff concluded, in the BVPS-2 IPEEE SER, that, according to GDC 4, GDC 19, and SRP Section 2.2.3, the BVPS plant is adequately protected and acceptable with respect to transportation and nearby facility hazards. This is also applicable to BVPS-1.

Based on the review of the lightning events that have occurred at the site, it was concluded that they were less severe than a complete loss of offsite power to BVPS-1. Also, according to Section 2.6 of NUREG-1407, the probability of a severe accident caused by lightning would be relatively low. Therefore, lightning is an insignificant contributor to core damage frequency for BVPS-1.

The contribution to the BVPS-1 total CDF from the other external events is less than 1.0E-06 per year, and as concluded in the BVPS-1 IPEEE, there are no vulnerabilities to the other external events at BVPS-1.

3.1.2.4 External Event Severe Accident Risk

External event severe accident risk assessment is integrated with the internal events risk; the PRA includes both internal and external. This assessment approach provides the means to evaluate SAMAs for both internal and external events impacts simultaneously without the need to separately estimate the impact of the potential improvements on external events.

3.2 LEVEL 2 PLANT SPECIFIC MODEL

The Level 2 PRA model determines release frequency, severity, and timing based on the Level 1 PRA, containment performance, and accident progression analyses.

3.2.1 Description of Level 2 PRA Model

The accident sequence analysis defines the manner in which expected plant response to each identified initiating event or initiating event category is represented and quantified. This accounts for successes and failures of safety functions and related systems, and human actions to determine whether or not core damage occurs. The result of the Level 1 accident sequence analysis is the definition of a set of event trees used to represent and quantify the accident sequences.

The Level 2 analysis extends the Level 1 analysis to investigate the release category potential for core damage end states found. A containment event tree (CET) is used to represent and quantify the release category potential when quantified with the Level 1 event trees.

The Level 2 analysis is highly interdependent with other Probabilistic Risk Assessment tasks. The accident sequence plant damage states (PDSs) define the categories of core damage sequences to be considered in the Level 2 analysis. The event tree used to represent and quantify the release category potential is linked to the event trees representing the Level 1 analysis.

Each end state of the plant model (front-end or Level 1) event trees defines an accident sequence that results from an initiating event followed by the success or failure of various plant systems and/or the success or failure of operators to respond to procedures or otherwise intervene to mitigate the accident. Each accident sequence has a unique signature due to the particular combination of top event successes and failures. Each accident sequence that results in core damage could be evaluated explicitly in terms of the accident progression and the release of radioactive materials, if any, into the environment. However, since there can be millions of such sequences, it is impractical to perform thermal-hydraulic analyses and CET split-fraction quantification for each accident sequence. Therefore, the Level 1 sequences are usually grouped into PDS (or accident class) bins, each of which collects all of those sequences for which the progression of core damage, the release of fission products from the fuel, the status of the containment and its systems, and the potential for mitigating source terms are similar. A detailed split-fraction analysis is then focused on specific sequences selected to represent risk-significant bins.

PDS bins have been used as the entry states (similar to initiating events for the plant model event trees) to the CETs. The PDS bins are characterized by thermodynamic conditions in the Reactor Coolant System (RCS) and the containment at the onset of core damage, and the availability or unavailability of both passive and active plant features that can terminate the accident or mitigate the release of radioactive materials into the environment.

However, this was not the case in the BVPS-1 PRA models, where the CET was linked directly to the Level 1 trees to generate the frequencies of the defined release categories. Although the CET was linked directly to the Level 1 trees, the concept of PDSs was retained to minimize the number of CET top event split fractions that must be calculated. Furthermore, the CET was quantified separately for a number of key PDSs to facilitate debugging of the rules used for assigning CET split fractions and binning sequences to appropriate release categories.

The PDSs are characterized in such a manner to facilitate Level 2 quantification. However, the core damage frequency need not be characterized using the same PDS bins. In fact, Level 1 results have been characterized using much broader bin definitions.

Representative accident sequences must be selected to quantify split-fraction values for the CET. If PDSs are defined, a representative accident sequence(s) is selected for each risk-significant PDS. These representative sequences are analyzed in detail with appropriate thermal-hydraulic and fission product transport codes such as the Modular Accident Analysis Program (MAAP), the Source Term Code Package (STCP), and/or the MELCOR program to characterize the timing of important events (such as the onset of severe core damage and reactor vessel melt-through) as well as the nature of the core damage, containment failure, and fission product release.

The BV1REV4 PDS groups are presented in Table 3.2.1-4.

PDS groups are evaluated in a Containment Event Tree. CET sequences are then grouped and binned in previously defined release category bins based on sequence and containment conditions as shown in Table 3.2.1-5 (Table 4.7-7 in the BVPS-1 IPE Summary Report submittal).

The IPE source term evaluation was based on radionuclide releases of 20 Beaver Valley release category bins plus an intact containment bin. However, in support of the SAMA, BVPS has elected to upgrade the source release fractions for select bounding release categories based on current plant specific MAAP-DBA analyses that account for EPU conditions. In support of SAMA evaluations it is not necessary to run a MAAP case to represent each individual IPE release class for BVPS (i.e., BV1 – BV21). The release categories identified in Table 3.2-1 are those that are applicable to the plant's Level 3 and SAMA evaluations and were re-evaluated using MAAP-DBA. The specific MAAP cases provided in the table were judged to be sufficient to represent each release category identified in the BVPS SAMA evaluation.

All MAAP-DBA cases were analyzed for 24 hours after the time of release, or demonstrated that a complete release has been produced (i.e., at least 98% of the noble gases have been released from containment).

The Level 2 quantification extends the Level 1 results of the Beaver Valley Unit 1 PRA to include the Level 2 results. This extension has been accomplished by linking the CET (discussed earlier in this section) to the Level 1 trees, and by assigning the end states of the linked Levels 1 and 2 trees to the appropriate release categories. For reporting, the release categories have been binned into four groups, as shown in Table 3.2.1-1. Basic Event Importances (Table 3.2.1-2) and Component Importances (Table 3.2.1-3) for the Large Early Release category group are provided for information.

Table 3.2.1-1: BV1REV4 Release Category Group Definition and Results			
Release Type	Description	Associated CDF (per year)	Percentage of Total CDF
I	Large, early containment failures and bypasses	7.54E-08	0.4%
II	Small, early containment failures and bypasses	8.07E-06	41.3%
III	Late containment failures	1.04E-05	53.1%
IV	Long-term contained releases (intact containment)	1.01E-06	5.2%
Total Plant CDF		1.95E-05	100%

Table 3.2.1-2: BV1REV4 Basic Event Importances for Total Plant LERF by Risk Reduction Worth				
Rank	Basic Event Name	Basic Event Description	RRW*	Associated SAMA
1	OGXXXX	Offsite Grid Fails Following Non-LOSP Initiator	4.67E+00	AC Power SAMAs
2	OPRSL3	Operator Fails to Gag Stuck Open SRV	1.52E+00	SAMA 164
3	AVFCTVMS101C	TV-MS-101C Fails to Close on Demand	1.09E+00	SGTR SAMAs
4	AVFCTVMS101B	TV-MS-101B Fails to Close on Demand	1.09E+00	SGTR SAMAs
5	AVFCTVMS101A	TV-MS-101A Fails to Close on Demand	1.09E+00	SGTR SAMAs
6	[CBFD52BYA CBFD52BYB CBFD52RTA CBFD52RTB]	Common Cause Failure on Demand of Reactor Trip Breakers	1.05E+00	ATWS SAMAs
7	CONTROLRODS	Control Rods Fail to Insert	1.04E+00	ATWS SAMAs
8	SVFCSVMS101C	SV-MS-101C Fails to Close on Demand	1.04E+00	SGTR SAMAs
9	SVFCSVMS102C	SV-MS-102C Fails to Close on Demand	1.04E+00	SGTR SAMAs
10	SVFCSVMS103C	SV-MS-103C Fails to Close on Demand	1.04E+00	SGTR SAMAs
* The Risk Reduction Worth (RRW) is defined by the following Fussell-Vesley (FV) relationship: RRW = 1 / (1 - FV)				

Table 3.2.1-3: BV1REV4 Component Importances for Total Plant LERF by Risk Reduction Worth				
Rank	**Component Name**	**Component Description**	**RRW***	**Associated SAMA**
1	TV-MS-101C	Loop 1C Main Steam Trip Valve	1.09E+00	SGTR SAMAs
2	TV-MS-101B	Loop 1B Main Steam Trip Valve	1.09E+00	SGTR SAMAs
3	TV-MS-101A	Loop 1A Main Steam Trip Valve	1.09E+00	SGTR SAMAs
4	1F/L-B10-ROD	Control Rods Fail to Insert	1.04E+00	ATWS SAMAs
5	SV-MS-101C	SV-MS-101C Fails to Close on Demand	1.04E+00	SGTR SAMAs
6	SV-MS-102C	SV-MS-102C Fails to Close on Demand	1.04E+00	SGTR SAMAs
7	SV-MS-103C	SV-MS-103C Fails to Close on Demand	1.04E+00	SGTR SAMAs
8	SV-MS-101B	SV-MS-101B Fails to Close on Demand	1.04E+00	SGTR SAMAs
9	SV-MS-102B	SV-MS-102B Fails to Close on Demand	1.04E+00	SGTR SAMAs
10	SV-MS-103B	SV-MS-103B Fails to Close on Demand	1.04E+00	SGTR SAMAs
* The Risk Reduction Worth (RRW) is defined by the following Fussell-Vesley (FV) relationship: RRW = 1 / (1 - FV)				

Table 3.2.1-4
BV1REV4 Level 1 Sequence Groupings

RCS Pressure at Core Damage	Containment Bypassed		Containment Not Isolated	Containment Isolated	
	Small (SBYP)	Large (LBYP)		With Heat Removal (WCHR)	No Heat Removal (NOHR)
Low (L)) (0-200 psia)	LOSBYP	LOLBYP	LONISO	LOWCHR	LONOHR
Medium (MD) (200-600 psia)	MDSBYP	--	MDNISO	MDWCHR	MDNOHR
High (HI) (600-2,000 psia)	HISBYP	--	HINISO	HIWCHR	HINOHR
System Setpoint (SY) (>2,000 psia)	SYSBYP	--	SYNISO	SYWCHR	SYNOHR

Table 3.2.1-5 Beaver Valley Unit 1 PRA Release Categories

Release Category	RCS Pressure			Containment Failure							Sprays?			Ex-Cont Retention*			Draft NUREG-1150 Dry PWR Cat	Major Release Type**
	High	Med	Low	Intact	Early	Late	Large	Small	Lrg Byp	Sm Byp	Yes	Partial	No	None	Mod-erate	Signif-icant		
BV1	X				X		X						X	X			1, 6, 16	I
BV2	X				X		X				X———	X		X			2, 7, 17	I
BV3		X	X		X		X						X	X			3, 5, 6, 18	I
BV4		X	X		X		X				X———	X		X			4, 7, 19	I
BV5	X———	X			X			X				X———	X		X		6	
BV6	X———	X			X			X			X				X		7	II
BV7			X		X			X				X———	X		X		6	
BV8			X		X			X			X				X		7	
BV9	X———	X				X	X						X	X			9	
BV10	X———	X				X	X				X———	X		X			8	
BV11			X			X	X						X	X			9	
BV12			X			X	X				X———	X		X			8	
BV13	X———	X				X		X				X———	X		X		10	III
BV14	X———	X				X		X			X				X		10	
BV15			X			X		X				X———	X		X		10	
BV16			X			X		X			X				X		10	
BV17	X———	X———	X			X		X			X———	X———	X			X	13, 14	
BV18	X———	X———	X						X———	X	X———	X———	X	X			12	I
BV19			X						X		X———	X———	X		X		11	
BV20	X———	X								X	X———	X———	X			X	11	II
BV21	X———	X———	X	X							X			X			15–No Failure	IV

* "None" = direct or nearly direct to atmosphere (DF < 2), "Moderate" = through large building or with limited flooding (DF = 2 to 10), "Significant" = through deep pool or isolated steam generator (DF > 10)

** I = Large, Early Release, or Bypass, S/T equal to or greater than PWR4 (WASH-1400)
II = Small, Early Release, S/T less than PWR4 (WASH-1400)
III = Late Release, very low S/T
IV = Long-Term Containment Integrity, Minimal Release
X------X Indicates that the Release Category groups together two or more different characteristics

Table 3.2.1-6: BVPS Release Categories Reanalyzed Using MAAP-DBA			
Release Category	**IPE Release Category Description**	**Representative MAAP Accident Sequence**	**Assumed Containment Failure Area**
BV1	High RCS Pressure, Early, Large, No CHR.	SBO with no AFW and no sprays available. Large containment failure.	1 ft^2
BV3	Med/Low RCS Pressure, Early, Large, No CHR.	LLOCA with no active injection and no sprays. Large containment failure.	1 ft^2
BV5	High/Med RCS Pressure, Early, Small, Partial/No CHR, Yes Aux. Building.	SBO with no AFW and no sprays available. LOCI with a small release through the aux. building.	0.1 ft^2
BV7	Low RCS Pressure, Early, Small, Partial/No CHR, Yes Aux. Building.	LLOCA with no active injection and no sprays. LOCI with a small release through the aux. building.	0.1 ft^2
BV9	High/Med RCS Pressure, Late, Large, No CHR.	SBO with no AFW and no sprays available. Large containment failure due to over-pressurization.	1 ft^2
BV10	High/Med RCS Pressure, Late, Large, Partial CHR.	TLOFW with no active injection and partial sprays available. Large containment failure from H_2 burn.	1 ft^2
BV12	Low RCS Pressure, Late, Large, Partial CHR.	LLOCA with no active injection and partial sprays available. Large containment failure from H_2 burn.	1 ft^2
BV13	High/Med RCS Pressure, Late, Small, Partial/No CHR, Yes Aux. Building.	SBO with no AFW and no sprays available. Small containment failure due to over-pressurization.	0.2 ft^2
BV15	Low RCS Pressure, Late, Small, Partial/No CHR, Yes Aux. Building.	LLOCA with no active injection and no sprays available. Small containment failure due to over-pressurization.	0.2 ft^2
BV17	High/Med/Low RCS Pressure, Late, Small, Yes/Partial/No CHR, Ground.	SBO with no AFW and no sprays available. Failure through base of containment.	1 ft^2
BV18	High/Med/Low RCS Pressure, Large/Small Bypass, Yes/Partial/No CHR, Little or No Ex-Cont Retention.	SGTR with a TLOFW, no active injection and no sprays available. Direct release through stuck open MSSVs,	Containment Bypassed (DF=1.0)
BV19	Low RCS Pressure, Large Bypass, Yes/Partial/No CHR, Moderate Ex-Cont. Retention.	Large ISLOCA through low pressure injection system, no injection and no sprays available. Aux. building release below water level (flooded building provides scrubbing).	Containment Bypassed (DF=4.3)
BV20	High/Med RCS Pressure, Small Bypass, Yes/Partial/No CHR, Significant Ex-Cont. Retention.	Small ISLOCA through low pressure injection system, no injection and no sprays available. Aux. building release below water level (flooded building provides scrubbing).	Containment Bypassed (DF=10)
BV21	High RCS Pressure, Intact Containment, CHR available.	SLOCA with a TLOFW, no injection during recirculation and sprays available. No containment failure.	2.5E-05 ft^2 (Based on 0.1% volume / day leakage)

3.2.2 Level 2 PRA Model Changes Since IPE Submittal

The major Level 2 changes incorporated into each revision of the Beaver Valley Unit 1 PRA model are discussed below. The individual affect on risk by incorporating each of these changes has not been analyzed.

Beaver Valley Unit 1 Revision 0

This revision represents the base case IPE quantification and resulted in a large early release frequency of 1.06E-05 / year for internal events.

Beaver Valley Unit 1 Revision 1

This revision represents the base case IPEEE quantification and resulted in a large early release frequency of 5.85E-06 / year for internal events. This reduction in LERF was due to Level 1 PRA model changes. There were no changes to the Level 2 PRA model.

Beaver Valley Unit 1 Revision 2

There was only 1 major Level 2 change incorporated into this updated BVPS-1 PRA model. This change was implemented due to a reevaluation of the impact of direct containment heating (DCH) on the frequency of large, early releases at Beaver Valley Units 1 and 2.

The Direct Containment Heating issue was identified in the NRC's Revised Severe Accident Research Plan as an important issue for resolution because of its potential for early containment failures. DCH was recognized to be a potential by which sensible heat energy can be transferred directly to the reactor vessel and subsequent blowdown of the molten debris and RCS fluids into the containment atmosphere. If the RCS pressure is sufficiently high, the blowdown of the RCS fluid through an opening in the bottom head of the reactor vessel can entrain molten core debris in the high-velocity blowdown gas and eject fragmented particles from the reactor cavity into the containment. This series of events is referred to as high pressure melt ejection.

The Beaver Valley IPE submittals were based on an understanding of DCH phenomena as it was portrayed in the documentation (NUREG-1150 and NUREG/CR-4551) for the NRC's probabilistic assessment of severe accidents of five plants. Since that time, the state of knowledge regarding DCH phenomena evolved as additional experiments and analyses were performed. Two subsequent reports, NUREG/CR-6109 (Reference 17) and NUREG/CR-6338 (Reference 18) were issued by the NRC that relate to the resolution of DCH for Westinghouse plants with large, dry containments, including the Beaver Valley subatmospheric containments.

The conclusion of these reports is that the intermediate compartment traps most of the debris dispersed from the reactor cavity and that the thermal-chemical interactions during this dispersal process are limited by the incoherence in the steam blowdown and melt entrainment process.

Based on these new reports, the split fraction values for determining large, early containment failures (i.e., the product of C2 and L2) have reduction factors ranging from approximately 42 to more than 30,000 when compared to the IPE submittal.

This change to the Level 2 model contributed to a large early release frequency of 7.06E-07 / year for internal events.

Beaver Valley Unit 1 Revision 3

Beaver Valley Unit 1 Revision 3 was made with the following model modifications. These changes contributed to a large early release frequency of 9.98E-07 / year for internal events.

There were four major Level 2 changes incorporated into the updated Beaver Valley Unit 1 PRA model. Three of these changes dealt with sequences involving induced SGTRs, large containment failures due to early hydrogen burns, and large containment failures due to alpha-mode (in-vessel steam explosions). Based on Westinghouse and industry state-of-the-art knowledge of these containment phenomenologies, it was then believed that the probabilities of these occurring are extremely low for large, dry containments (that is, non ice-condenser) and are not credible in large containment failures or bypasses.

The fourth change altered the way steam generator tube ruptures were accounted for in the LERF definition. In this PRA model update, only steam generator tube ruptures sequences that have a depleted RWST or have a loss of all secondary cooling were considered to be LERF contributors. It was assumed that leakage from the RCS would continue indefinitely through the faulted steam generator and the core would uncover after the RWST depletes. This is in agreement with WCAP-15955 (Reference 19), “Steam Generator Tube Rupture PRA Notebook”.

Beaver Valley Unit 1 Revision 4

There were no specific changes to the Beaver Valley Unit 1 Level 2 model in this revision. Changes to the Level 1 model resulted in a large early release frequency of 7.41E-08 / year for internal events.

Based on a review that was performed to identify the effects of the EPU and the contributors to the Large Early Release conditional probability, there were no Level 2 changes required due to the BVPS-1 containment conversion. The sub-atmospheric containment modeling in the previous BVPS-1 PRAs assumed no large pre-existing containment isolation failures, due to the inability to maintain a containment vacuum. This assumption remains valid for EPU and the slightly subatmospheric conditions now existing, as the containment vacuum pumps are not expected to maintain the slightly sub-atmospheric condition for large pre-existing containment isolation failures, as well.

However, there were two major contributors to the reduction in the Level 2 LERF incorporated into the updated BVPS-1 PRA model. These consisted of the replacement steam generators installed during 1R17, and taking credit for improved procedures for isolating LOCAs outside containment. Since the replacement steam generators have a lower tube rupture frequency, the contribution to LERF via containment bypass events initiated by SGTRs that are either faulted with the RWST depleted or with failures of auxiliary feedwater that lead to an unscrubbed release, is reduced. The other major reduction in LERF is due to taking credit for operators to isolate another type of containment bypass event, initiated by interfacing systems LOCAs outside containment. This guidance is provided in emergency operating procedure ECA-1.2 "LOCA Outside Containment", which was enhanced to have operators identify and isolate the break by closing MOV-1SI-890C, the low head safety injection (LHSI) valve to the RCS cold legs. Performing this action would terminate the most probable interfacing systems LOCA break f low, which is postulated to occur in the LHSI lines; thereby, reducing its contribution to LERF.

3.3 MODEL REVIEW SUMMARY

Regulatory Guide (RG) 1.174 (Reference 38), Section 2.2.3 states that the quality of a PRA analysis used to support an application is measured in terms of its appropriateness with respect to scope, level of detail and technical acceptability, and that these are to be commensurate with the application for which it is intended.

The PRA technical acceptability of the model used in the development of this Severe Accident Mitigation Alternatives application has been demonstrated by a peer review process. The peer review was conducted in July 2002, by the [former] Westinghouse Owner's Group, with the final documentation of the review issued in December 2002. The overall conclusions of the peer review were:

> All of the technical elements were graded as sufficient to support applications requiring the capabilities defined for grade 2. The BVPS PRA thus provides an appropriate and sufficiently robust tool to support such activities as Maintenance Rule implementation, supported as necessary by deterministic insights and plant expert panel input.
>
> All 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 but in some cases this is contingent upon implementation of recommended enhancements.

After the peer review, the preliminary Category A and B facts and observations that potentially impacted the model were entered into the BVPS Corrective Action Program, dispositioned, and incorporated into updated PRA model. Although the facts and observations (F&Os) were written for the BVPS-2 model, if applicable, the resolution was applied to the BVPS-1 model as well. All Category A and B F&Os were implemented on Unit 1. Those models have since undergone another revision, but the incorporated resolution of Category A and B F&Os were maintained in the revision. The BVPS-1 Category A facts and F&Os and dispositions are summarized in the following paragraphs.

In addition, FENOC provided summaries of the BVPS Peer Review Category A and B F&Os in the following previously docketed letters:

- Pearce/USNRC, Beaver Valley Power Station, Unit No. 2, BV-2 Docket No. 50-412, License No. NPF-73, Response to a Request for Additional Information in Support of License Amendment Requests No. 180, dated October 24, 2003, Serial L-03-160.
- Pearce/USNRC, Beaver Valley Power Station, Unit No. 1 and No. 2, BV-1 Docket No. 50-334, License No. DPR-66 and BV-2 Docket No. 50-412, License No. NPF-73, Response to a Request for Additional Information in Support of License Amendment Requests Nos. 306 and 176, dated October 29, 2004, Serial L-04-141.

<u>**Category A Observations**</u>

F&O 1
Summary: This observation was identified in the Accident Sequence Analysis Sub-element regarding the RCP seal LOCA model. It was recognized that the BVPS RCP seal LOCA model used the WOG 2000 as a basis, but in a way that is more optimistic than most other Westinghouse plants. The BV2REV3A PRA model, RCP seal LOCA success criteria was developed from best estimate MAAP runs performed specifically for BVPS-2. Since certain MAAP results did not go to core uncovery in the assumed 24-hour mission time for the smaller break seal LOCA sizes, they were binned into the success (non CDF) end state, even though electric power or service water was not restored. The peer review team felt that additional MAAP analyses should be performed to investigate the impact of varying MAAP input parameters on the resultant time to core uncovery, and extend the run time to show stable plant conditions.

Resolution: Additional MAAP uncertainty cases for BVPS-1 were performed using pessimistically biased values along with setting input parameters to their high or low limits. These cases were run out to 48-hours or until core damage occurred. The success state for the BV1REV3 PRA model was redefined as any case (including uncertainties) that did not go to core damage before 48-hours. For cases that went to core damage before 48-hours but after 24-hours, additional electric power recovery values were used, based on NUREG/CR-5496. For cases that lead to core uncovery before 24-hours, a plant specific electric power recovery model was used. If electric power recovery was successful for these cases, the sequence was also binned to the success end state.

F&O 2
Summary: This observation was identified in the Human Reliability Analysis (HRA), Post-Initiator Human Actions Sub-element. It was observed that the BVPS human error rates were developed using the Success Likelihood Index Methodology (SLIM) based on calibration curves from other plant HRAs from the mid-1980's. The peer review team recommended that these calibration curves be updated with current operator performance in the nuclear power industry.

Resolution: As a resolution to this PRA Peer Review observation all operator actions having a Risk Achievement Worth (RAW) greater than 2 (generally accepted as the risk significant threshold) were compared to similar actions for all Westinghouse plants by using the WOG/B&WOG PRA Comparison Database (Revisions 2 and 3). Additionally, a smaller subset of these plants was also looked at. These consisted of; Westinghouse 3-loop plants (since these were assumed to have similar operation action completion times based on plant power to heatup volume ratios), plants that also used the SLIM process, and Indian Point 2, which received a superior finding in their Human Reliability Analysis peer review.

The results of this comparison show that for the operator actions that were compared, the human error rates used in the BV1REV3 PRA model are all within the range of both comparison groups defined above. It is therefore believed that the basic error curves used in the calibration of the BV1REV3 HRA are not grossly out of date, and that the current human error rates used in the PRA model are acceptable as is. Moreover, as a final resolution to this observation, future BVPS PRA models will use the EPRI HRA Calculator, which uses a more current and robust methodology.

F&O 3
Summary: This observation was identified in the Human Reliability Analysis, Dependence Among Actions Sub-element. It was observed that the BVPS HRA did not have a documented process to perform a systematic search for dependent human actions credited on individual sequences and a method to adjust dependencies between multiple human error rates in the same sequence. The peer review team recommended that a robust technique be developed, documented, and used for the identification and quantification of dependent human error rates (HERs).

Resolution: In the initial development of the IPE HRA, an effort was made to eliminate the dependency between human actions by adjusting the split fraction value of the second dependent action, given that the first action failed. For example, if the operators failed to manually reestablish Main Feedwater following the failure of Auxiliary Feedwater, the human error rate for implementing Bleed and Feed cooling later in the accident progression was adjusted upwards. If the dependent actions were required to take place in the same period of time during the accident progression, the second dependent action was assigned to be a guaranteed failure. For example, if the operators failed to cooldown and depressurize the RCS by using the secondary coolant system, no credit was given to the operators to depressurize the RCS using the Pressurizer PORVs.

However, as a resolution to this PRA Peer Review observation a method was established to verify that all dependent operator actions were captured by reviewing sequences with two or more failed split fractions that have a contribution from human actions. Of the sequences reviewed, the human actions were either previously adjusted during the IPE HRA, or were determined to be independent between split fractions. This independence was based on the actions not being conducted by the same set of operators (e.g., control room Reactor Operator action vs. local Auxiliary Plant Operator action), or different procedures being used separated by sufficient time in the accident progression (e.g., actions to makeup to the RWST given SI recirculation failures, following operator actions to align a spare Service Water pump earlier in the accident sequence progression).

Human actions that are modeled in a single top event have appropriate dependencies modeled in the event tree logic and rules. Moreover, as a final resolution to this observation, future BVPS PRA models will use the EPRI HRA Calculator, which uses a more current and robust methodology to identify human action dependencies.

3.4 LEVEL 3 PRA MODEL

The BVPS-1/2 Level 3 PRA model determines off-site dose and economic impacts of severe accidents based on the Level 1 PRA results, the Level 2 PRA results, atmospheric transport, mitigating actions, dose accumulation, early and latent health effects, and economic analyses.

The MELCOR Accident Consequence Code System (MACCS2) Version 1.13.1 was used to perform the calculations of the off-site consequences of a severe accident. This code is documented in NUREG/CR-6613 (Reference 28), "Code Manual for MACCS2: Volumes 1 and 2."

Plant-specific release data included the time-dependent nuclide distribution of releases and release frequencies. The behavior of the population during a release (evacuation parameters) was based on plant and site-specific set points. These data were used in combination with site-specific meteorology to simulate the probability distribution of impact risks (both exposures and economic effects) to the surrounding 50-mile radius population as a result of the release accident sequences at Beaver Valley.

The following sections describe input data for the MACCS2 (Reference 28) analysis tool. The analyses are provided in References 32-35.

3.4.1 Population Distribution

The population surrounding the Beaver Valley Power Station site, up to a 50 mile radius, was estimated based on the most recent United States Census Bureau decennial census data. Details are provided in "Calculation Package for Population Projections – Beaver Valley Power Station" (Reference 29). The population distribution was estimated in 9 concentric bands at 0 to 1 mile, 1 to 2 miles, 2 to 5 miles, 5 to 10 miles, 10 to 15 miles, 15 to 20 miles, 20 to 30 miles, 30 to 40 miles, and 40 to 50 miles, and 16 directional sectors with each direction consisting of 22.5 degrees. The population was projected to the year 2047 by calculating an annual growth rate for each county in the 50 mile radius derived from state and national population projections. Geometric growth rates were calculated for each county in Ohio and Pennsylvania based on 2030 county projections. However, if the county population had decreased from 2000 to 2030, it was assumed there was no growth through 2030 (i.e., the 2030 population was equal to the 2000 population), and the national growth rate was applied from 2030 to 2047 to obtain an overall multiplier fore the 2047 projection. For West Virginia, projections were available through 2050. The annual growth rate was applied to obtain a 2047 multiplier, unless a negative growth rate existed, in which case no growth was assumed. The population distribution used in this analysis is provided in the following table.

Table 3.4.1-1 Population Projections Used in SAMA Analysis

From Radius	To Radius	Direction	Code	2000 Population	2047 Population
0	1	N	1	0	0
0	1	NNE	2	0	0
0	1	NE	3	93	110
0	1	ENE	4	38	45
0	1	E	5	88	104
0	1	ESE	6	0	0
0	1	SE	7	7	8
0	1	SSE	8	0	0
0	1	S	9	0	0
0	1	SSW	10	0	0
0	1	SW	11	2	2
0	1	WSW	12	0	0
0	1	W	13	0	0
0	1	WNW	14	0	0
0	1	NW	15	132	156
0	1	NNW	16	53	63
1	2	N	17	197	232
1	2	NNE	18	62	73
1	2	NE	19	4	5
1	2	ENE	20	7	8
1	2	E	21	74	87
1	2	ESE	22	64	76
1	2	SE	23	116	137
1	2	SSE	24	22	26
1	2	S	25	18	21
1	2	SSW	26	35	41
1	2	SW	27	25	30
1	2	WSW	28	73	86
1	2	W	29	141	166
1	2	WNW	30	0	0
1	2	NW	31	1,651	1,948
1	2	NNW	32	470	555
2	5	N	33	835	985
2	5	NNE	34	1,016	1,199
2	5	NE	35	1,130	1,333
2	5	ENE	36	683	806
2	5	E	37	1,039	1,226
2	5	ESE	38	713	841
2	5	SE	39	284	335
2	5	SSE	40	637	752
2	5	S	41	486	573
2	5	SSW	42	742	876
2	5	SW	43	619	730
2	5	WSW	44	217	256
2	5	W	45	723	853

Table 3.4.1-1 Population Projections Used in SAMA Analysis (Cont.)

From Radius	To Radius	Direction	Code	2000 Population	2047 Population
2	5	WNW	46	802	946
2	5	NW	47	1,753	2,069
2	5	NNW	48	573	676
5	10	N	49	2,317	2,734
5	10	NNE	50	3,875	4,573
5	10	NE	51	18,262	21,549
5	10	ENE	52	14,995	17,694
5	10	E	53	19,461	22,964
5	10	ESE	54	7,307	8,606
5	10	SE	55	1,589	1,840
5	10	SSE	56	1,777	2,090
5	10	S	57	4,734	5,586
5	10	SSW	58	1,284	1,512
5	10	SW	59	3,604	3,875
5	10	WSW	60	1,886	1,918
5	10	W	61	19,534	21,213
5	10	WNW	62	7,332	8,652
5	10	NW	63	2,156	2,544
5	10	NNW	64	1,283	1,514
10	15	N	65	4,297	5,070
10	15	NNE	66	20,102	23,720
10	15	NE	67	18,866	22,262
10	15	ENE	68	13,403	15,810
10	15	E	69	18,133	20,507
10	15	ESE	70	31,028	31,750
10	15	SE	71	5,136	5,187
10	15	SSE	72	1,105	1,132
10	15	S	73	1,064	1,099
10	15	SSW	74	5,120	5,285
10	15	SW	75	9,357	9,802
10	15	WSW	76	1,931	2,095
10	15	W	77	6,926	7,980
10	15	WNW	78	3,491	4,119
10	15	NW	79	2,716	3,205
10	15	NNW	80	1,975	2,331
15	20	N	81	2,679	3,161
15	20	NNE	82	19,651	23,188
15	20	NE	83	8,256	10,097
15	20	ENE	84	26,225	35,104
15	20	E	85	20,890	21,130
15	20	ESE	86	32,047	32,367
15	20	SE	87	20,102	20,303
15	20	SSE	88	5,210	5,342
15	20	S	89	5,479	5,643
15	20	SSW	90	23,299	23,522
15	20	SW	91	6,325	7,364
15	20	WSW	92	1,568	1,850

Table 3.4.1-1 Population Projections Used in SAMA Analysis (Cont.)

From Radius	To Radius	Direction	Code	2000 Population	2047 Population
15	20	W	93	1,535	1,811
15	20	WNW	94	3,151	3,718
15	20	NW	95	5,793	6,836
15	20	NNW	96	9,801	11,565
20	30	N	97	40,448	47,729
20	30	NNE	98	25,927	31,193
20	30	NE	99	11,544	15,668
20	30	ENE	100	26,859	36,797
20	30	E	101	73,055	77,064
20	30	ESE	102	410,196	414,298
20	30	SE	103	227,938	230,716
20	30	SSE	104	39,083	40,229
20	30	S	105	5,494	5,656
20	30	SSW	106	38,710	41,558
20	30	SW	107	20,523	24,217
20	30	WSW	108	5,090	6,155
20	30	W	109	4,182	5,480
20	30	WNW	110	10,727	12,776
20	30	NW	111	33,243	39,227
20	30	NNW	112	38,242	45,126
30	40	N	113	27,393	32,324
30	40	NNE	114	14,394	17,649
30	40	NE	115	20,468	28,041
30	40	ENE	116	52,734	72,065
30	40	E	117	88,641	97,229
30	40	ESE	118	343,130	347,829
30	40	SE	119	114,676	116,792
30	40	SSE	120	49,039	50,510
30	40	S	121	10,274	10,553
30	40	SSW	122	35,720	38,675
30	40	SW	123	10,554	12,454
30	40	WSW	124	6,314	8,164
30	40	W	125	15,333	21,441
30	40	WNW	126	25,741	30,543
30	40	NW	127	19,379	22,864
30	40	NNW	128	218,945	258,355
40	50	N	129	67,035	79,101
40	50	NNE	130	26,361	31,533
40	50	NE	131	9,705	13,035
40	50	ENE	132	31,197	37,772
40	50	E	133	43,404	48,911
40	50	ESE	134	115,071	120,818
40	50	SE	135	79,774	83,809
40	50	SSE	136	21,216	21,842
40	50	S	137	5,221	5,321
40	50	SSW	138	72,617	79,681
40	50	SW	139	12,337	14,558

Table 3.4.1-1 Population Projections Used in SAMA Analysis (Cont.)

From Radius	To Radius	Direction	Code	2000 Population	2047 Population
40	50	WSW	140	9,276	11,210
40	50	W	141	19,628	24,920
40	50	WNW	142	83,296	97,999
40	50	NW	143	26,594	30,210
40	50	NNW	144	123,093	145,250
			Total	**3,273,502**	**3,607,001**

3.4.2 Economic Data

The Environmental Protection Agency's computer program SECPOP was the basis for the economic data used in the offsite evaluations done in this analysis. This code utilized county economic factors derived from the 2000 census and various other government sources dated 1997 to 1999. For the preparation of data for the Beaver Valley model, the county data file was updated to circa 2002 for the 23 counties within 50 miles of the plant. Reference 33 provides the input data used in this analysis:

Variable	Description	BVPS 1/2 Value
DPRATE(1)	Property depreciation rate (per yr)	0.20
DSRATE(1)	Investment rate of return (per yr)	0.12
EVACST(2)	Daily cost for a person who has been evacuated ($/person-day)	$49
POPCST(2)	Population relocation cost ($/person)	$13,727
RELCST(2)	Daily cost for a person who is relocated ($/person-day)	$49
CDFRM(2)	Cost of farm decontamination for various levels of decontamination ($/hectare)	$1,169 & $2,598
CDNFRM(2)	Cost of non-farm decontamination per resident person for various levels of decontamination ($/person)	$6,236 & $16,630
DLBCST(2)	Average cost of decontamination labor ($/man-year)	$72,756
VALWF(2)	Value of farm wealth ($/hectare)	$6,957
VALWNF(2)	Value of non-farm wealth average in US ($/person)	$181,881

(1) DPRATE and DSRATE are based on MACCS2 Users Manual (Reference 28)

(2) Calc 17676-0002 "Beaver Valley Power Station - MACCS2 Input Data".

3.4.3 Nuclide Release

The equilibrium core inventory was assumed at the end of a fuel cycle with fuel from three different fuel cycles in equal proportions. It was originally developed using ORIGEN-S as described in the BVPS Containment Conversion Licensing Report (Reference 31).

The following table provides the inventory of the core at shutdown used in this analysis. This information is from Reference 30, Section 5.2.3.3

Table 3.4.3-1 Core Inventory

Nuclide	Core Inventory (Curies)
Ag-111	5.05E+6
Ag-112	2.28E+6
Am-241	1.17E+4
Am-242	7.04E+6
Am-244	1.89E+7
Ba-137m	9.35E+6
Ba-139	1.41E+8
Ba-140	1.42E+8
Br-82	3.02E+5
Br-83	9.37E+6
Ce-141	1.30E+8
Ce-143	1.21E+8
Ce-144	9.82E+7
Cm-242	2.42E+6
Cm-244	5.97E+5
Cs-134	1.57E+7
Cs-134m	3.69E+6
Cs-135m	4.39E+6
Cs-136	4.97E+6
Cs-137	9.81E+6
Cs-138	1.48E+8
Eu-156	2.29E+7
Eu-157	2.41E+6
H-3	4.36E+4
I-129	2.86E+0
I-130	2.07E+6
I-131	7.78E+7
I-132	1.14E+8
I-133	1.60E+8
I-134	1.77E+8
I-135	1.52E+8
Kr-83m	9.46E+6
Kr-85	8.27E+5
Kr-85m	1.95E+7
Kr-87	3.91E+7
Kr-88	5.43E+7
La-140	1.46E+8

Table 3.4.3-1 Core Inventory (Cont.)

Nuclide	Core Inventory (Curies)
La-141	1.29E+8
La-142	1.26E+8
La-143	1.20E+8
Mo-101	1.33E+8
Mo-99	1.45E+8
Nb-95	1.34E+8
Nb-95m	1.52E+6
Nb-97	1.27E+8
Nb-97m	1.19E+8
Nd-147	5.22E+7
Nd-149	3.02E+7
Nd-151	1.58E+7
Np-238	3.98E+7
Np-239	1.66E+9
Np-240	4.32E+6
Pd-109	3.26E+7
Pm-147	1.38E+7
Pm-148	1.41E+7
Pm-148m	2.37E+6
Pm-149	4.82E+7
Pm-151	1.60E+7
Pr-142	5.57E+6
Pr-143	1.18E+8
Pr-144	9.89E+7
Pr-144m	1.38E+6
Pr-147	5.18E+7
Pu-238	3.40E+5
Pu-239	2.86E+4
Pu-240	3.87E+4
Pu-241	1.13E+7
Pu-242	2.01E+2
Pu-243	4.23E+7
Rb-86	1.69E+5
Rb-88	5.57E+7
Rb-89	7.26E+7
Rh-103m	1.26E+8
Rh-105	8.16E+7
Rh-106	5.13E+7

Table 3.4.3-1 Core Inventory (Cont.)

Nuclide	Core Inventory (Curies)
Ru-103	1.26E+8
Ru-105	8.90E+7
Ru-106	4.63E+7
Sb-127	6.92E+6
Sb-129	2.52E+7
Sb-130	8.37E+6
Sb-131	6.09E+7
Se-83	4.42E+6
Sm-153	4.02E+7
Sm-155	3.11E+6
Sm-156	1.93E+6
Sn-127	2.78E+6
Sr-89	7.61E+7
Sr-90	7.21E+6
Sr-91	9.50E+7
Sr-92	1.01E+8
Tc-101	1.33E+8
Tc-104	1.05E+8
Tc-99m	1.29E+8
Te-127	6.81E+6
Te-127m	1.13E+6
Te-129	2.40E+7
Te-129m	4.87E+6
Te-131	6.54E+7
Te-131m	1.57E+7
Te-132	1.12E+8
Te-133	8.66E+7
Te-133m	7.12E+7
Te-134	1.41E+8
U-239	1.66E+9
Xe-131m	1.08E+6
Xe-133	1.60E+8
Xe-133m	5.05E+6
Xe-135	4.84E+7
Xe-135m	3.36E+7
Xe-138	1.36E+8

Table 3.4.3-1 Core Inventory (Cont.)

Nuclide	Core Inventory (Curies)
Y-90	7.49E+6
Y-91	9.87E+7
Y-91m	5.51E+7
Y-92	1.02E+8
Y-93	7.73E+7
Y-94	1.23E+8
Y-95	1.28E+8
Zr-95	1.33E+8
Zr-97	1.26E+8

Table 3.4.3-2 provides a description of the release characteristics evaluated in this analysis.

Table 3.4.3-2 Release Descriptions

Release Category	Representative Bins	MACCS2 Run Code	Plume Number	Energy Level (cal/sec)	Energy Level (W)	Release Height (m)	Time of Release (hr)	Duration (hr)	Alarm Delay (hr)
Variable			**NUMREL**		**PLHEAT**	**PLHITE**	**PDELAY**	**PLUDUR**	**OALARM**
INTACT	BV21	A	1	454	1.90E+03	43.7	4	4	4
INTACT	BV21	A	2	262.84	1.10E+03	43.7	8	20	4
VSEQ-ECF	BV19	B	1	3.75E+07	1.57E+08	3.2	2	0.5	1
SGTR-ECF	BV18	C	1	8.48E+07	3.55E+08	26.82	8	0.5	1
DCH-ECF	BV1, BV3	D	1	6.59E+07	2.76E+08	43.7	3	4	1
VSEQ-SECF	BV20	E	1	1.00E+06	4.19E+06	3.2	3	1	1
LOCI-SECF	BV7	F	1	2.15E+06	9.00E+06	12	1.5	0.5	1
LOCI-SECF	BV7	F	2	1.12E+06	4.69E+06	12	2	9.5	1
BV5-SECF	BV5	K	1	2.15E+06	9.00E+06	43.7	1.5	0.5	1
BV5-SECF	BV5	K	2	1.12E+06	4.69E+06	43.7	2	9.5	1
Large-Late	BV10, BV12	G	1	6.59E+07	2.76E+08	43.7	10	0.5	4
Large-Late	BV10, BV12	G	2	1.27E+07	5.32E+07	43.7	10.5	3	4
Small-Late	BV13, BV15	H	1	1.31E+07	5.49E+07	43.7	25	0.5	4
Small-Late	BV13, BV15	H	2	2.63E+06	1.10E+07	43.7	25.5	9.5	4
H2 Burn-Late	BV9	I	1	6.59E+07	2.76E+08	43.7	10	0.5	4
H2 Burn-Late	BV9	I	2	1.27E+07	5.32E+07	43.7	10.5	3.5	4
BMMT-Late	BV17	J	1	6.59E+07	2.76E+08	0	24	1	4

3.4.4 Emergency Response

A reactor scram signal begins each evaluated accident sequence. A General Emergency is declared when plant conditions degrade to the point where it is judged that there is a credible risk to the public. Therefore, the timing of the General Emergency declaration is sequence specific and alarms range from 1 to 4 hours for the release sequences evaluated.

The MACCS2 User's Guide input parameters of 95 percent of the population within 10 miles of the plant [Emergency Planning Zone (EPZ)] evacuating and 5 percent not evacuating were employed. These values have been used in similar studies (e.g., Hatch, Calvert Cliffs, (SNOC 2000) and (BGE 1998)) and are conservative relative to the NUREG-1150 study, which assumed evacuation of 99.5 percent of the population within the EPZ.

The evacuation speed was calculated by comparing the travel time estimates to the travel distances required. The Aliquippa/Hopewell area has the greatest population density in the EPZ, requires the longest evacuation time, and is only a few miles from the edge of the EPZ. It follows that the slowest and most conservative evacuation speeds would occur in this area. Based on the published evacuation routes and the population distribution in the area, a typical travel distance to the edge of the EPZ from this area is approximately 3 miles. Using the worst case evacuation time (inclement weather and persons without transportation) of 6¼ hours an average evacuation speed of 0.2 m/s was determined.

Three evacuation sensitivity cases were also performed to determine the impact of evacuation assumptions. One sensitivity case reduced the evacuation speed by a factor of four (0.05 m/sec) and the second increased the speed to 2.24 m/s (5 mph). The third sensitivity case assumed a factor of 1.5 increase in the alarm time, thus delaying the commencement of physical evacuation. The results are discussed in Section 8.

3.4.5 Meteorological Data

Each year of meteorological data consists of 8,760 weather data sets of hourly recordings of wind direction, wind speed, atmospheric stability, and accumulated precipitation. The data were from the Beaver Valley Power Station site weather facility for the years 2001, 2002, 2003, 2004, and 2005. MACCS2 does not permit missing data, so bad or missing data were filled in with National Oceanic and Atmospheric Administration (NOAA) data from the Pittsburgh International Airport (nearest most complete source of data) obtained from the NOAA Internet website. The approach used in this analysis was to perform MACCS2 analyses for each of the years for which meteorological data was gathered and combine the results after the MACCS2 analyses rather than before. Due to the consideration of five years of weather data, it is assumed that the average result from the analysis would be considered typical and representative. No one year was found to be conservative with respect to all release sequences.

3.5 SEVERE ACCIDENT RISK RESULTS

Using the MACCS2 code, the dose and economic costs associated with a severe accident at Beaver Valley were calculated for each of the years for which meteorological data was gathered. This information is provided below in Table 3.5-1 and Table 3.5-2, respectively. The average value of the yearly result for each release category was used in the remainder of the analysis to represent the dose and cost for each of the specific release categories.

Table 3.5-1 Total L-EFFECTIVE LIFE Dose in Sieverts

Release Category	MACCS2 Run Code	BVPS Composite Weather Sensitivity Results 2001	2002	2003	2004	2005	Average
INTACT	A	8	7	8	7	7	8
ECF							
VSEQ	B	50,400	47,200	51,000	53,600	40,800	48,600
SGTR	C	44,500	41,400	43,800	46,500	37,000	42,640
DCH	D	86,800	84,800	86,600	76,400	77,600	82,440
SECF							
VSEQ	E	50,500	48,000	47,800	46,900	44,800	47,600
LOCI	F	35,200	35,500	33,200	34,000	36,400	34,860
BV5	K	43,800	39,800	41,300	41,000	42,700	41,720
LATE							
Large	G	1,530	1,440	1,780	1,600	1,450	1,560
Small	H	20,200	19,200	18,800	18,600	20,500	19,460
H2 Burn	I	19,300	17,200	17,600	16,300	17,900	17,660
BMMT	J	7,680	7,250	7,200	7,990	6,990	7,422

Table 3.5-2 Total Economic Costs in Dollars

Release Category	MACCS2 Run Code	BVPS Composite Weather Sensitivity Results 2001	2002	2003	2004	2005	Average
INTACT	A	6.400E+03	5.600E+03	5.590E+03	1.000E+04	7.510E+03	7.020E+03
ECF							
VSEQ	B	3.530E+10	3.260E+10	3.100E+10	3.350E+10	3.390E+10	3.326E+10
SGTR	C	4.280E+10	3.790E+10	3.580E+10	4.080E+10	3.840E+10	3.914E+10
DCH	D	4.800E+10	5.010E+10	5.010E+10	4.400E+10	5.000E+10	4.844E+10
SECF							
SGTR	E	2.540E+10	2.560E+10	2.690E+10	2.440E+10	2.920E+10	2.630E+10
LOCI	F	2.650E+10	2.520E+10	2.570E+10	2.460E+10	2.840E+10	2.608E+10
BV5	K	1.130E+10	1.070E+10	1.190E+10	1.050E+10	1.240E+10	1.136E+10
LATE							
Large	G	1.180E+08	1.260E+08	1.430E+08	1.590E+08	1.310E+08	1.354E+08
Small	H	1.090E+10	1.010E+10	1.150E+10	1.040E+10	1.170E+10	1.092E+10
H2 Burn	I	6.670E+09	6.220E+09	6.460E+09	5.600E+09	5.900E+09	6.170E+09
BMMT	J	4.380E+09	4.360E+09	5.480E+09	4.450E+09	4.700E+09	4.674E+09

3.6 MAJOR PRA MODELING DIFFERENCES BETWEEN BVPS UNIT 1 AND UNIT 2

Listed below are some major design differences between the BVPS Units that are accounted for in the PRA models. In addition, key differences in the BVPS PRA models were also previously docketed in Attachment B of the following letter.

- Pearce/USNRC, Beaver Valley Power Station, Unit No. 1 and No. 2, BV-1 Docket No. 50-334, License No. DPR-66 and BV-2 Docket No. 50-412, License No. NPF-73, Response to a Request for Additional Information in Support of License Amendment Requests Nos. 306 and 176, dated October 29, 2004, Serial L-04-141.

1. Unit 1 has an additional feedwater pump (Dedicated AFW Pump) powered off the ERF diesel generator, which can be used during an SBO. This pump can provide secondary heat removal even if the SG are water solid, so it is not dependant on battery life. Unit 2 only has the Turbine-Driven AFW Pump, which fail if the SG goes water solid, so it is dependent on battery life during SBO conditions. Plant specific SBO MAAP analyses show that with the DAFW pump, as long as the RCP seal LOCA is initially less than 182 gpm and operators cooldown and depressurize the RCS, Unit 1 will not melt or uncover the core during a 48 hour period following the SBO. At Unit 2, this is not the case, and the core will uncover and melt during a 48 hour period following the SBO.

2. The Unit 1 Emergency DC Battery Rooms are constructed with concrete block walls, which have limited seismic capacity. At Unit 2 the Emergency DC Battery Rooms are constructed with reinforced concrete walls that have significant seismic capacity.

3. At Unit 1 the steam generators were replaced during 1RO17 and therefore have about half of the SGTR initiating event frequency of the Unit 2 value (2.09E-03 vs. 4.82E-03).

4. The Unit 2 RWST volume is about twice the size of the Unit 1 volume (~ 860,000 gal vs. ~440,000 gal).

5. At Unit 1 the atmospheric steam dump valves have a higher capacity than Unit 2 (294,400 lbs/hr vs. 235,000 lbs/hr) and therefore the RCS cooldown and depressurization using the secondary heat removal system success criteria is different. Unit 1 only requires 1 ASDV and feedwater to the associated SG, while Unit 2 requires 2 ASDVs with feedwater to both associated SGs.

6. Unit 2 normally has two Service Water pumps in service, while Unit 1 normally only has one River Water pump in service. Therefore, since the success criteria for both Units is one River Water/Service Water pump, there is a lower system failure probability at Unit 2 due to not having to start a standby pump given the failure of a running pump.

4 COST OF SEVERE ACCIDENT RISK / MAXIMUM BENEFIT

Cost/benefit evaluation of SAMAs is based upon the cost of implementation of a SAMA compared to the averted onsite and offsite costs resulting from the implementation of that SAMA. The methodology used for this evaluation was based upon the NRC's guidance for the performance of cost-benefit analyses (Reference 20). This guidance involves determining the net value for each SAMA according to the following formula:

Net Value = (APE + AOC + AOE + AOSC) – COE

where APE = present value of averted public exposure ($),
AOC = present value of averted offsite property damage costs ($),
AOE = present value of averted occupational exposure ($),
AOSC = present value of averted onsite costs ($)
COE = cost of enhancement ($).

If the net value of a SAMA is negative, the cost of implementing the SAMA is larger than the benefit associated with the SAMA and is not considered beneficial. The derivation of each of these costs is described in below.

The following specific values were used for various terms in the analyses:

Present Worth

The present worth was determined by:

$$PW = \frac{1 - e^{-rt}}{r}$$

Where:

r is the **discount rate = 7%** (assumed throughout these analyses)
t is the **duration of the license renewal = 20 years**
PW is the present worth of a string of annual payments = **10.76**

Dollars per REM

The conversion factor used for assigning a monetary value to on-site and off-site exposures was **$2,000/person-rem averted**. This is consistent with the NRC's regulatory analysis guidelines presented in and used throughout NUREG/BR-0184, Reference 20.

On-site Person REM per Accident

The occupational exposure associated with severe accidents was assumed to be **23,300 person-rem/accident.** This value includes a short-term component of 3,300 person-rem/accident and a long-term component of 20,000 person-rem/accident. These estimates are consistent with the "best estimate" values presented in Section 5.7.3 of Reference 20. In the cost/benefit analyses, the accident-related on-site exposures were calculated using the best estimate exposure components applied over the on-site cleanup period.

On-site Cleanup Period

In the cost/benefit analyses, the accident-related on-site exposures were calculated over a **10-year cleanup period**.

Present Worth On-site Cleanup Cost per Accident

The estimated cleanup cost for severe accidents was assumed to be **$1.5E+09/accident** (undiscounted). This value was derived by the NRC in Reference 20, Section 5.7.6.1, Cleanup and Decontamination. This cost is the sum of equal annual costs over a 10-year cleanup period. At a 7% discount rate, the present value of this stream of costs is **$1.1E+09**.

4.1 OFF-SITE EXPOSURE COST

Accident-Related Off-Site Dose Costs

Offsite doses were determined using the MACCS2 model developed for BVPS-1. Costs associated with these doses were calculated using the following equation:

$$APE = \left(F_S D_{P_S} - F_A D_{P_A}\right) R \frac{1 - e^{-rt_f}}{r} \qquad (1)$$

where:

APE = monetary value of accident risk avoided due to population doses, after discounting

R = monetary equivalent of unit dose, ($/person-rem)

F = accident frequency (events/yr)
D_P = population dose factor (person-rems/event)
S = status quo (current conditions)
A = after implementation of proposed action
r = real discount rate
t_f = analysis period (years).

Using the values for r, t_f, and R given above:

$$W_P = (\$2.15E + 4)\left(F_S D_{P_S} - F_A D_{P_A}\right)$$

4.2 OFF-SITE ECONOMIC COST

Accident-Related Off-Site Property Damage Costs

Offsite damage was determined using the MACCS2 model developed for BVPS-1. Costs associated with these damages were calculated using the following equation:

$$AOC = \left(F_S P_{D_S} - F_A P_{D_A}\right)\frac{1 - e^{-rt_f}}{r}$$

where:

AOC = monetary value of accident risk avoided due to offsite property damage, after discounting
F = accident frequency (events/yr)
P_D = offsite property loss factor (dollars/event)
r = real discount rate
t_f = analysis period (years).

4.3 ON-SITE EXPOSURE COST

Methods for Calculating Averted Costs Associated with Onsite Accident Dose Costs

a) **Immediate Doses** (at time of accident and for immediate management of emergency)

For the case where the plant is in operation, the equations in Reference 20 can be expressed as:

$$W_{IO} = \left(F_S D_{IO_S} - F_A D_{IO_A}\right) R \frac{1 - e^{-rt_f}}{r} \qquad (1)$$

where:

W_{IO} = monetary value of accident risk avoided due to immediate doses, after discounting
R = monetary equivalent of unit dose, ($/person-rem)
F = accident frequency (events/yr)
D_{IO} = immediate occupational dose (person-rems/event)
S = status quo (current conditions)
A = after implementation of proposed action
r = real discount rate
t_f = analysis period (years).

The values used are:

R = $2000/person rem
r = .07
D_{IO} = 3,300 person-rems /accident (best estimate)

The license extension time of 20 years is used for $t_{f.}$

For the basis discount rate, assuming F_A is zero, the best estimate of the limiting savings is

$$W_{IO} = \left(F_S D_{IO_S}\right) R \frac{1-e^{-rt_f}}{r}$$
$$= 3300 * F * \$2000 * \frac{1-e^{-.07*20}}{.07}$$
$$= F * \$6{,}600{,}000 * 10.763$$
$$= F * \$0.71E + 8, (\$).$$

b) **Long-Term Doses** (process of cleanup and refurbishment or decontamination)

For the case where the plant is in operation, the equations in Reference 20 can be expressed as:

$$W_{LTO} = \left(F_S D_{LTO_S} - F_A D_{LTO_A}\right) R * \frac{1-e^{-rt_f}}{r} * \frac{1-e^{-rm}}{rm} \tag{2}$$

where:

W_{IO} = monetary value of accident risk avoided long term doses, after discounting, \$

m = years over which long-term doses accrue.

The values used are:

R = \$2000/person rem
r = .07
D_{LTO} = 20,000 person-rem /accident (best estimate)
m = “as long as 10 years”

The license extension period of 20 years is used for $t_{f.}$

For the discount rate of 7%, assuming F_A is zero, the best estimate of the limiting savings is

$$W_{LTO} = \left(F_S D_{LTO_S}\right) R * \frac{1-e^{-rt_f}}{r} * \frac{1-e^{-rm}}{rm}$$
$$= \left(F_S 20000\right)\$2000 * \frac{1-e^{-.07*20}}{.07} * \frac{1-e^{-.07*10}}{.07*10}$$
$$= F_S * \$40{,}000{,}000 * 10.763 * 0.719$$
$$= F_S * \$3.10E + 8, (\$).$$

c) **Total Accident-Related Occupational (On-site) Exposures**

Combining equations (1) and (2) above, using delta (Δ) to signify the difference in accident frequency resulting from the proposed actions, and using the above numerical values, the long term accident related on-site (occupational) exposure avoided (AOE) is:

Best Estimate:

$$AOE = \quad W_{IO} + \quad W_{LTO} = \quad F * \$(0.71 + 3.1)E + 8 = \quad F * \$3.81E + 8 \ (\$)$$

4.4 ON-SITE ECONOMIC COST

Methods for Calculation of Averted Costs Associated with Accident-Related On-Site Property Damage

a) **Cleanup/Decontamination**

Reference 20 assumes a total cleanup/decontamination cost of \$1.5E+9 as a reasonable estimate and this same value was adopted for these analyses. Considering a 10-year cleanup period, the present value of this cost is:

$$PV_{CD} = \left(\frac{C_{CD}}{m}\right)\left(\frac{1 - e^{-rm}}{r}\right)$$

Where

PV_{CD} = Present value of the cost of cleanup/decontamination.
C_{CD} = Total cost of the cleanup/decontamination effort.
m = Cleanup period.
r = Discount rate.

Based upon the values previously assumed:

$$PV_{CD} = \left(\frac{\$1.5E + 9}{10}\right)\left(\frac{1 - e^{-.07*10}}{.07}\right)$$

$$PV_{CD} = \$1.079E + 9$$

This cost is integrated over the term of the proposed license extension as follows

$$U_{CD} = PV_{CD}\frac{1 - e^{-rt_f}}{r}$$

Based upon the values previously assumed:

$$U_{CD} = \$1.079E + 9\ [10.763]$$

$$U_{CD} = \$1.161E + 10$$

b) **Replacement Power Costs**

Replacement power costs, U_{RP}, are an additional contributor to onsite costs. These are calculated in accordance with NUREG/BR-0184, Section 5.6.7.2.[1] Since replacement power will be needed for that time period following a severe accident, for the remainder of the expected generating plant life, long-term power replacement calculations have been used. The calculations are based on the 910 MWe reference plant, and are appropriately scaled for the 984 MWe BVPS-1. The present value of replacement power is calculated as follows:

$$PV_{RP} = \left(\frac{(\$1.2E + 8)\dfrac{(Ratepwr)}{(910MWe)}}{r} \right) \left(1 - e^{-rt_f}\right)^2$$

Where

PV_{RP}	=	Present value of the cost of replacement power for a single event.
	=	
t_f	=	Analysis period (years).
r	=	Discount rate.
Ratepwr	=	Rated power of the unit

The $1.2E+8 value has no intrinsic meaning but is a substitute for a string of non-constant replacement power costs that occur over the lifetime of a "generic" reactor after an event (from Reference 20). This equation was developed per NUREG/BR-0184 for discount rates between 5% and 10% only.

For discount rates between 1% and 5%, Reference 20 indicates that a linear interpolation is appropriate between present values of $1.2E+9 at 5% and $1.6E+9 at 1%. So for discount rates in this range the following equation was used to perform this linear interpolation.

$$PV_{RP} = \left\{ (\$1.6E + 9) - \left(\frac{[(\$1.6E + 9) - (\$1.2E + 9)]}{[5\% - 1\%]} * [\, r_s - 1\%] \right) \right\} * \left\{ \frac{Ratepwr}{910MWe} \right\}$$

Where

r_s	=	Discount rate (small), between 1% and 5%.
Ratepwr	=	Rated power of the unit

[1] The section number for Section 5.6.7.2 apparently contains a typographical error. This section is a subsection of 5.7.6 and follows 5.7.6.1. However, the section number as it appears in the NUREG will be used in this document.

To account for the entire lifetime of the facility, U_{RP} was then calculated from PV_{RP}, as follows:

$$U_{RP} = \frac{PV_{RP}}{r}\left(1 - e^{-rt_f}\right)^2$$

Where
U_{RP} = Present value of the cost of replacement power over the life of the facility.

Again, this equation is only applicable in the range of discount rates from 5% to 10%. NUREG/BR-0184 states that for lower discount rates, linear interpolations for U_{RP} are recommended between \$1.9E+10 at 1% and \$1.2E+10 at 5%. The following equation was used to perform this linear interpolations:

$$U_{RP} = \left\{\left(\$1.9E+10\right) - \left(\frac{\left[\left(\$1.2E+10\right) - \left(\$1.2E+10\right)\right]}{\left[5\% - 1\%\right]} * \left[r_s - 1\%\right]\right)\right\} * \left\{\frac{Ratepwr}{910MWe}\right\}$$

Where
r_s = Discount rate (small), between 1% and 5%.
Ratepwr = Rated power of the unit

c) **Repair and Refurbishment**

It is assumed that the plant would not be repaired/refurbished; therefore, there is not contribution to averted onsite costs from this source.

d) **Total Onsite Property Damage Costs**

The net present value of averted onsite damage costs is, therefore:

$$AOSC = F * \left(U_{CD} + U_{RP}\right)$$

Where F = Annual frequency of the event.

4.5 TOTAL COST OF SEVERE ACCIDENT RISK / MAXIMUM BENEFIT

Cost/benefit evaluation of the maximum benefit is baseline risk of the plant converted dollars by summing the contributors to cost.

Maximum Benefit Value = (APE + AOC + AOE + AOSC)
where APE = present value of averted public exposure (\$),
AOC = present value of averted offsite property damage costs (\$),

AOE = present value of averted occupational exposure ($),
AOSC = present value of averted onsite costs ($)

For Beaver Valley Unit 1, this value is $5,129,572 as shown below.

Parameter	Unit 1 Present Dollar Value ($)
Averted Public Exposure	$1,246,705
Averted offsite costs	$3,483,791
Averted occupational exposure	$7,402
Averted onsite costs	$391,674
Total	$5,129,572

The costs are dominated by the early small and late small release categories. The dominant accident sequences that result in these release categories are largely the result of fire and seismic initiating events. These initiating events are explicitly modeled in the PRA.

5 SAMA IDENTIFICATION

A list of SAMA candidates was developed by reviewing the major contributors to CDF and population dose based on the plant-specific risk assessment and the standard PWR list of enhancements from Reference 24 (NEI 05-01). This section discusses the SAMA selection process and its results.

5.1 PRA IMPORTANCE

The top core damage sequences and the components/systems having the greatest potential for risk reduction were examined to determine whether additional SAMAs could be identified from these sources.

Use of Importance Measures
Risk reduction worth (RRW) of the components in the baseline model was used to identify those basic events that could have a significant potential for reducing risk. Components with risk reduction worth (RRW) >1.005 were identified as the most important components. A similar review was performed on a system basis. The components and systems were reviewed to ensure that each component and system is covered by an existing SAMA item or added to the list if not.

Use of the Top Sequences
The top sequences leading to core melt were reviewed. A key result is that no single PRA sequence makes up a large fraction of the core damage frequency. The sequences were reviewed

to ensure that initiators and failures identified in the sequences were either covered by existing SAMAs or added to the list of plant specific SAMAs.

5.2 PLANT IPE

The Beaver Valley Unit 1 PRA identified some potential vulnerabilities. Corresponding enhancements have been considered. As noted in the IPE, large fractions of the CDF were associated with RCP seal LOCA and station blackout. Other major contributors were containment bypass/isolation failure, loss of switchgear HVAC and transients without scram.

These accident categories are not always mutually exclusive. One of the top ranked sequences illustrates this clearly. A loss of offsite power will challenge the onsite emergency power system. Failure of both emergency diesels would result in a station blackout. The consequential loss of seal injection and component cooling water to the reactor coolant pumps (RCP) thermal barrier could eventually lead to a RCP seal LOCA. Station blackout and RCP seal LOCA are both conditions of this scenario that can result in core uncovery and damage.

In order to determine vulnerabilities, the major accident categories were evaluated along with the top-ranking sequences contributing to CDF.

The Beaver Valley Unit 1 potential enhancements are listed in Table 5.2-1.

Table 5.2-1. Beaver Valley Unit 1 IPE Potential Enhancements

Vulnerability	Procedure or Design Enhancement	Impact of Enhancement	CDF Importance		Status
			Percent of CDF	Risk * Reduction Worth	
AC Power Generation Capability for Station Blackout	Provide Beaver Valley Units 1 and 2 with 4,160 V Bus Crosstie Capability	Adds a success path for blackout on Unit 2 when both Unit 1 diesel generators work, and vice versa	30.4	0.8647	Intent Met . SAMAs 9 and 154
Reactor Trip breaker failure	Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	19.9	0.7949	SAMA 155, Analysis shows that actions outside the control room cannot be performed quickly enough. PRA updates have reduced the contribution from ATWS events.
Pressurizer PORV block valve alignment	Operate plant with all PORV block valves open or provide procedures to open block valves when Main Feedwater is lost.	Increased pressure relief capacity to prevent reactor vessel rupture during ATWS.	15.6	0.8900	Intent Met. SAMA 156; Normal operational alignment has all 3 block valves open. The configuration risk management program limits the amount of time the PORV block valves can remain closed.
Loss of Emergency Switchgear Room HVAC	Enhanced Loss of HVAC Procedures	Confidence that operators will prevent thermal damage to switchgear	15.5	0.8708	Intent Met. SAMA 157, further analysis shows that there is a long time for installation of temporary ventilation.
RCP Seal Cooling for Station Blackout	Potential modifications under review	Reduced frequency of RCP seal LOCA resulting from blackout	13.8	**	Intent Met, SAMA 158
Battery Capacity for steam generator level instruments for station blackout	Enhance procedures on shedding loads or using portable battery chargers. One train of the battery chargers will be powered from the site operable emergency diesel generator once the Station Blackout Unit crosstie modification is complete.	Extended operating time for steam generator level instruments for loss of all AC power scenarios	10.7	0.8933	Intent Met. SAMA 159
Pressurizer PORV sticking open after loss of offsite power	Eliminate challenge by defeating the 100% load rejection capability	Reduced frequency of pressurizer PORV sticking open	2.0	0.9808	SAMA 160, turbine trip above 30% causes reactor trip.
Fast 4,160 V Bus Transfer Failure	Explicit Procedure and Training on breaker repair or change out	Reduced frequency that breaker failures will challenge diesel generators	1.5	0.9855	Intent Met , SAMA 161

Note: * The risk reduction worth is the factor decrease in CDF that would be realized if the failure probability of the affected system were decreased to 0.0 (i.e., guaranteed success).
** Included in the AC power generation capability for station blackout risk reduction worth value.

5.3 PLANT IPEEE

Potential improvements to reduce the risk in dominant fire zones and to reduce seismic risk and risk from other external events were evaluated in the Beaver Valley Unit 1 IPEEE. The list of candidate improvements and their status is documented in the IPEEE and reproduced in Table 3.1.2-1 in this report.

5.4 INDUSTRY SAMA CANDIDATES

The generic PWR enhancement list from Table 14 of Reference 24 was included in the list of Phase I SAMA candidates to assure adequate consideration of potential enhancements identified by other industry studies.

5.5 PLANT STAFF INPUT TO SAMA CANDIDATES

The Beaver Valley plant staff provided plant specific items that were included in the evaluation. These are identified in the list of SAMA candidates by their source.

5.6 LIST OF PHASE I SAMA CANDIDATES

Table 5.6-1 provides the combined list of potential SAMA candidates considered in the Beaver Valley Unit 1 SAMA analysis. From this table it can be seen that 189 SAMA candidates were identified for consideration.

Table 5.6-1 List of SAMA Candidates

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
1	Provide additional DC battery capacity.	Extended DC power availability during an SBO.	AC/DC	1, C
2	Replace lead-acid batteries with fuel cells.	Extended DC power availability during an SBO.	AC/DC	1
3	Add additional battery charger or portable, diesel-driven battery charger to existing DC system.	Improved availability of DC power system.	AC/DC	1, C
4	Improve DC bus load shedding.	Extended DC power availability during an SBO.	AC/DC	1
5	Provide DC bus cross-ties.	Improved availability of DC power system.	AC/DC	1
6	Provide additional DC power to the 120/240V vital AC system.	Increased availability of the 120 V vital AC bus.	AC/DC	1
7	Add an automatic feature to transfer the 120V vital AC bus from normal to standby power.	Increased availability of the 120 V vital AC bus.	AC/DC	1
8	Increase training on response to loss of two 120V AC buses which causes inadvertent actuation signals.	Improved chances of successful response to loss of two 120V AC buses.	AC/DC	1
9	Provide an additional diesel generator.	Increased availability of on-site emergency AC power.	AC/DC	1
10	Revise procedure to allow bypass of diesel generator trips.	Extended diesel generator operation.	AC/DC	1
11	Improve 4.16-kV bus cross-tie ability.	Increased availability of on-site AC power.	AC/DC	1, A
12	Create AC power cross-tie capability with other unit (multi-unit site)	Increased availability of on-site AC power.	AC/DC	1, A
13	Install an additional, buried off-site power source.	Reduced probability of loss of off-site power.	AC/DC	1
14	Install a gas turbine generator.	Increased availability of on-site AC power.	AC/DC	1
15	Install tornado protection on gas turbine generator.	Increased availability of on-site AC power.	AC/DC	1
16	Improve uninterruptible power supplies.	Increased availability of power supplies supporting front-line equipment.	AC/DC	1
17	Create a cross-tie for diesel fuel oil (multi-unit site).	Increased diesel generator availability.	AC/DC	1
18	Develop procedures for replenishing diesel fuel oil.	Increased diesel generator availability.	AC/DC	1
19	Use fire water system as a backup source for diesel cooling.	Increased diesel generator availability.	AC/DC	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
20	Add a new backup source of diesel cooling.	Increased diesel generator availability.	AC/DC	1
21	Develop procedures to repair or replace failed 4 KV breakers.	Increased probability of recovery from failure of breakers that transfer 4.16 kV non-emergency buses from unit station service transformers.	AC/DC	1, A
22	In training, emphasize steps in recovery of off-site power after an SBO.	Reduced human error probability during off-site power recovery.	AC/DC	1
23	Develop a severe weather conditions procedure.	Improved off-site power recovery following external weather-related events.	AC/DC	1
24	Bury off-site power lines.	Improved off-site power reliability during severe weather.	AC/DC	1
25	Install an independent active or passive high pressure injection system.	Improved prevention of core melt sequences.	Core Cooling	1
26	Provide an additional high pressure injection pump with independent diesel.	Reduced frequency of core melt from small LOCA and SBO sequences.	Core Cooling	1
27	Revise procedure to allow operators to inhibit automatic vessel depressurization in non-ATWS scenarios.	Extended HPCI and RCIC operation.	Core Cooling	1
28	Add a diverse low pressure injection system.	Improved injection capability.	Core Cooling	1
29	Provide capability for alternate injection via diesel-driven fire pump.	Improved injection capability.	Core Cooling	1
30	Improve ECCS suction strainers.	Enhanced reliability of ECCS suction.	Core Cooling	1
31	Add the ability to manually align emergency core cooling system recirculation.	Enhanced reliability of ECCS suction.	Core Cooling	1
32	Add the ability to automatically align emergency core cooling system to recirculation mode upon refueling water storage tank depletion.	Enhanced reliability of ECCS suction.	Core Cooling	1
33	Provide hardware and procedure to refill the reactor water storage tank once it reaches a specified low level.	Extended reactor water storage tank capacity in the event of a steam generator tube rupture (or other LOCAs challenging RWST capacity) .	Core Cooling	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
34	Provide an in-containment reactor water storage tank.	Continuous source of water to the safety injection pumps during a LOCA event, since water released from a breach of the primary system collects in the in-containment reactor water storage tank, and thereby eliminates the need to realign the safety injection pumps for long-term post-LOCA recirculation.	Core Cooling	1
35	Throttle low pressure injection pumps earlier in medium or large-break LOCAs to maintain reactor water storage tank inventory.	Extended reactor water storage tank capacity.	Core Cooling	1
36	Emphasize timely recirculation alignment in operator training.	Reduced human error probability associated with recirculation failure.	Core Cooling	1
37	Upgrade the chemical and volume control system to mitigate small LOCAs.	For a plant like the Westinghouse AP600, where the chemical and volume control system cannot mitigate a small LOCA, an upgrade would decrease the frequency of core damage.	Core Cooling	1
38	Change the in-containment reactor water storage tank suction from four check valves to two check and two air-operated valves.	Reduced common mode failure of injection paths.	Core Cooling	1
39	Replace two of the four electric safety injection pumps with diesel-powered pumps.	Reduced common cause failure of the safety injection system. This SAMA was originally intended for the Westinghouse-CE System 80+, which has four trains of safety injection. However, the intent of this SAMA is to provide diversity within the high- and low-pressure safety injections systems.	Core Cooling	1
40	Provide capability for remote, manual operation of secondary side pilot-operated relief valves in a station blackout.	Improved chance of successful operation during station blackout events in which high area temperatures may be encountered (no ventilation to main steam areas).	Core Cooling	1
41	Create a reactor coolant depressurization system.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	Core Cooling	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
42	Make procedure changes for reactor coolant system depressurization.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	Core Cooling	1
43	Add redundant DC control power for SW pumps.	Increased availability of SW.	Cooling Water	1
44	Replace ECCS pump motors with air-cooled motors.	Elimination of ECCS dependency on component cooling system.	Cooling Water	1
45	Enhance procedural guidance for use of cross-tied component cooling or service water pumps.	Reduced frequency of loss of component cooling water and service water.	Cooling Water	1
46	Add a service water pump.	Increased availability of cooling water.	Cooling Water	1
47	Enhance the screen wash system.	Reduced potential for loss of SW due to clogging of screens.	Cooling Water	1
48	Cap downstream piping of normally closed component cooling water drain and vent valves.	Reduced frequency of loss of component cooling water initiating events, some of which can be attributed to catastrophic failure of one of the many single isolation valves.	Cooling Water	1
49	Enhance loss of component cooling water (or loss of service water) procedures to facilitate stopping the reactor coolant pumps.	Reduced potential for reactor coolant pump seal damage due to pump bearing failure.	Cooling Water	1
50	Enhance loss of component cooling water procedure to underscore the desirability of cooling down the reactor coolant system prior to seal LOCA.	Reduced probability of reactor coolant pump seal failure.	Cooling Water	1
51	Additional training on loss of component cooling water.	Improved success of operator actions after a loss of component cooling water.	Cooling Water	1
52	Provide hardware connections to allow another essential raw cooling water system to cool charging pump seals.	Reduced effect of loss of component cooling water by providing a means to maintain the charging pump seal injection following a loss of normal cooling water.	Cooling Water	1
53	On loss of essential raw cooling water, proceduralize shedding component cooling water loads to extend the component cooling water heat-up time.	Increased time before loss of component cooling water (and reactor coolant pump seal failure) during loss of essential raw cooling water sequences.	Cooling Water	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
54	Increase charging pump lube oil capacity.	Increased time before charging pump failure due to lube oil overheating in loss of cooling water sequences.	Cooling Water	1
55	Install an independent reactor coolant pump seal injection system, with dedicated diesel.	Reduced frequency of core damage from loss of component cooling water, service water, or station blackout.	Cooling Water	1
56	Install an independent reactor coolant pump seal injection system, without dedicated diesel.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	Cooling Water	1
57	Use existing hydro test pump for reactor coolant pump seal injection.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout, unless an alternate power source is used..	Cooling Water	1
58	Install improved reactor coolant pump seals.	Reduced likelihood of reactor coolant pump seal LOCA.	Cooling Water	1
59	Install an additional component cooling water pump.	Reduced likelihood of loss of component cooling water leading to a reactor coolant pump seal LOCA.	Cooling Water	1
60	Prevent makeup pump flow diversion through the relief valves.	Reduced frequency of loss of reactor coolant pump seal cooling if spurious high pressure injection relief valve opening creates a flow diversion large enough to prevent reactor coolant pump seal injection.	Cooling Water	1
61	Change procedures to isolate reactor coolant pump seal return flow on loss of component cooling water, and provide (or enhance) guidance on loss of injection during seal LOCA.	Reduced frequency of core damage due to loss of seal cooling.	Cooling Water	1
62	Implement procedures to stagger high pressure safety injection pump use after a loss of service water.	Extended high pressure injection prior to overheating following a loss of service water.	Cooling Water	1
63	Use fire prevention system pumps as a backup seal injection and high pressure makeup source.	Reduced frequency of reactor coolant pump seal LOCA.	Cooling Water	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
64	Implement procedure and hardware modifications to allow manual alignment of the fire water system to the component cooling water system, or install a component cooling water header cross-tie.	Improved ability to cool residual heat removal heat exchangers.	Cooling Water	1
65	Install a digital feed water upgrade.	Reduced chance of loss of main feed water following a plant trip.	Feedwater/Condensate	1
66	Create ability for emergency connection of existing or new water sources to feedwater and condensate systems.	Increased availability of feedwater.	Feedwater/Condensate	1
67	Install an independent diesel for the condensate storage tank makeup pumps.	Extended inventory in CST during an SBO.	Feedwater/Condensate	1
68	Add a motor-driven feedwater pump.	Increased availability of feedwater.	Feedwater/Condensate	1
69	Install manual isolation valves around auxiliary feedwater turbine-driven steam admission valves.	Reduced dual turbine-driven pump maintenance unavailability.	Feedwater/Condensate	1
70	Install accumulators for turbine-driven auxiliary feedwater pump flow control valves.	Eliminates the need for local manual action to align nitrogen bottles for control air following a loss of off-site power.	Feedwater/Condensate	1
71	Install a new condensate storage tank (auxiliary feedwater storage tank).	Increased availability of the auxiliary feedwater system.	Feedwater/Condensate	1
72	Modify the turbine-driven auxiliary feedwater pump to be self-cooled.	Improved success probability during a station blackout.	Feedwater/Condensate	1
73	Proceduralize local manual operation of auxiliary feedwater system when control power is lost.	Extended auxiliary feedwater availability during a station blackout. Also provides a success path should auxiliary feedwater control power be lost in non-station blackout sequences.	Feedwater/Condensate	1
74	Provide hookup for portable generators to power the turbine-driven auxiliary feedwater pump after station batteries are depleted.	Extended auxiliary feedwater availability.	Feedwater/Condensate	1
75	Use fire water system as a backup for steam generator inventory.	Increased availability of steam generator water supply.	Feedwater/Condensate	1
76	Change failure position of condenser makeup valve if the condenser makeup valve fails open on loss of air or power.	Allows greater inventory for the auxiliary feedwater pumps by preventing condensate storage tank flow diversion to the condenser.	Feedwater/Condensate	1
77	Provide a passive, secondary-side heat-rejection loop consisting of a condenser and heat sink.	Reduced potential for core damage due to loss-of-feedwater events.	Feedwater/Condensate	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
78	Modify the startup feedwater pump so that it can be used as a backup to the emergency feedwater system, including during a station blackout scenario.	Increased reliability of decay heat removal.	Feedwater/Condensate	1
79	Replace existing pilot-operated relief valves with larger ones, such that only one is required for successful feed and bleed.	Increased probability of successful feed and bleed.	Feedwater/Condensate	1
80	Provide a redundant train or means of ventilation.	Increased availability of components dependent on room cooling.	HVAC	1
81	Add a diesel building high temperature alarm or redundant louver and thermostat.	Improved diagnosis of a loss of diesel building HVAC.	HVAC	1
82	Stage backup fans in switchgear rooms.	Increased availability of ventilation in the event of a loss of switchgear ventilation.	HVAC	1
83	Add a switchgear room high temperature alarm.	Improved diagnosis of a loss of switchgear HVAC.	HVAC	1
84	Create ability to switch emergency feedwater room fan power supply to station batteries in a station blackout.	Continued fan operation in a station blackout.	HVAC	1
85	Provide cross-unit connection of uninterruptible compressed air supply.	Increased ability to vent containment using the hardened vent.	IA/Nitrogen	1
86	Modify procedure to provide ability to align diesel power to more air compressors.	Increased availability of instrument air after a LOOP.	IA/Nitrogen	1
87	Replace service and instrument air compressors with more reliable compressors which have self-contained air cooling by shaft driven fans.	Elimination of instrument air system dependence on service water cooling.	IA/Nitrogen	1
88	Install nitrogen bottles as backup gas supply for safety relief valves.	Extended SRV operation time.	IA/Nitrogen	1
89	Improve SRV and MSIV pneumatic components.	Improved availability of SRVs and MSIVs.	IA/Nitrogen	1
90	Create a reactor cavity flooding system.	Enhanced debris cool ability, reduced core concrete interaction, and increased fission product scrubbing.	Containment Phenomena	1
91	Install a passive containment spray system.	Improved containment spray capability.	Containment Phenomena	1
92	Use the fire water system as a backup source for the containment spray system.	Improved containment spray capability.	Containment Phenomena	1
93	Install an unfiltered, hardened containment vent.	Increased decay heat removal capability for non-ATWS events, without scrubbing released fission products.	Containment Phenomena	1
94	Install a filtered containment vent to remove decay heat. Option 1: Gravel Bed Filter; Option 2: Multiple Venturi Scrubber	Increased decay heat removal capability for non-ATWS events, with scrubbing of released fission products.	Containment Phenomena	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
95	Enhance fire protection system and standby gas treatment system hardware and procedures.	Improved fission product scrubbing in severe accidents.	Containment Phenomena	1
96	Provide post-accident containment inerting capability.	Reduced likelihood of hydrogen and carbon monoxide gas combustion.	Containment Phenomena	1
97	Create a large concrete crucible with heat removal potential to contain molten core debris.	Increased cooling and containment of molten core debris. Molten core debris escaping from the vessel is contained within the crucible and a water cooling mechanism cools the molten core in the crucible, preventing melt-through of the base mat.	Containment Phenomena	1
98	Create a core melt source reduction system.	Increased cooling and containment of molten core debris. Refractory material would be placed underneath the reactor vessel such that a molten core falling on the material would melt and combine with the material. Subsequent spreading and heat removal from the vitrified compound would be facilitated, and concrete attack would not occur.	Containment Phenomena	1
99	Strengthen primary/secondary containment (e.g., add ribbing to containment shell).	Reduced probability of containment over-pressurization.	Containment Phenomena	1
100	Increase depth of the concrete base mat or use an alternate concrete material to ensure melt-through does not occur.	Reduced probability of base mat melt-through.	Containment Phenomena	1
101	Provide a reactor vessel exterior cooling system.	Increased potential to cool a molten core before it causes vessel failure, by submerging the lower head in water.	Containment Phenomena	1
102	Construct a building to be connected to primary/secondary containment and maintained at a vacuum.	Reduced probability of containment over-pressurization.	Containment Phenomena	1
103	Institute simulator training for severe accident scenarios.	Improved arrest of core melt progress and prevention of containment failure.	Containment Phenomena	1
104	Improve leak detection procedures.	Increased piping surveillance to identify leaks prior to complete failure. Improved leak detection would reduce LOCA frequency.	Containment Phenomena	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
105	Delay containment spray actuation after a large LOCA.	Extended reactor water storage tank availability.	Containment Phenomena	1
106	Install automatic containment spray pump header throttle valves.	Extended time over which water remains in the reactor water storage tank, when full containment spray flow is not needed.	Containment Phenomena	1
107	Install a redundant containment spray system.	Increased containment heat removal ability.	Containment Phenomena	1
108	Install an independent power supply to the hydrogen control system using either new batteries, a non-safety grade portable generator, existing station batteries, or existing AC/DC independent power supplies, such as the security system diesel.	Reduced hydrogen detonation potential.	Containment Phenomena	1
109	Install a passive hydrogen control system.	Reduced hydrogen detonation potential.	Containment Phenomena	1
110	Erect a barrier that would provide enhanced protection of the containment walls (shell) from ejected core debris following a core melt scenario at high pressure.	Reduced probability of containment failure.	Containment Phenomena	1
111	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	Reduced ISLOCA frequency.	Containment Bypass	1
112	Add redundant and diverse limit switches to each containment isolation valve.	Reduced frequency of containment isolation failure and ISLOCAs.	Containment Bypass	1
113	Increase leak testing of valves in ISLOCA paths.	Reduced ISLOCA frequency.	Containment Bypass	1
114	Install self-actuating containment isolation valves.	Reduced frequency of isolation failure.	Containment Bypass	1
115	Locate residual heat removal (RHR) inside containment	Reduced frequency of ISLOCA outside containment.	Containment Bypass	1
116	Ensure ISLOCA releases are scrubbed. One method is to plug drains in potential break areas so that break point will be covered with water.	Scrubbed ISLOCA releases.	Containment Bypass	1
117	Revise EOPs to improve ISLOCA identification.	Increased likelihood that LOCAs outside containment are identified as such. A plant had a scenario in which an RHR ISLOCA could direct initial leakage back to the pressurizer relief tank, giving indication that the LOCA was inside containment.	Containment Bypass	1
118	Improve operator training on ISLOCA coping.	Decreased ISLOCA consequences.	Containment Bypass	1
119	Institute a maintenance practice to perform a 100% inspection of steam generator tubes during each refueling outage.	Reduced frequency of steam generator tube ruptures.	Containment Bypass	1
120	Replace steam generators with a new design.	Reduced frequency of steam generator tube ruptures.	Containment Bypass	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
121	Increase the pressure capacity of the secondary side so that a steam generator tube rupture would not cause the relief valves to lift.	Eliminates release pathway to the environment following a steam generator tube rupture.	Containment Bypass	1
122	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture	Enhanced depressurization capabilities during steam generator tube rupture.	Containment Bypass	1
123	Proceduralize use of pressurizer vent valves during steam generator tube rupture sequences.	Backup method to using pressurizer sprays to reduce primary system pressure following a steam generator tube rupture.	Containment Bypass	1
124	Provide improved instrumentation to detect steam generator tube ruptures, such as Nitrogen-16 monitors).	Improved mitigation of steam generator tube ruptures.	Containment Bypass	1
125	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.	Reduced consequences of a steam generator tube rupture.	Containment Bypass	1
126	Install a highly reliable (closed loop) steam generator shell-side heat removal system that relies on natural circulation and stored water sources	Reduced consequences of a steam generator tube rupture.	Containment Bypass	1
127	Revise emergency operating procedures to direct isolation of a faulted steam generator.	Reduced consequences of a steam generator tube rupture.	Containment Bypass	1
128	Direct steam generator flooding after a steam generator tube rupture, prior to core damage.	Improved scrubbing of steam generator tube rupture releases.	Containment Bypass	1
129	Vent main steam safety valves in containment.	Reduced consequences of a steam generator tube rupture.	Containment Bypass	1
130	Add an independent boron injection system.	Improved availability of boron injection during ATWS.	ATWS	1
131	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	Improved equipment availability after an ATWS.	ATWS	1
132	Provide an additional control system for rod insertion (e.g., AMSAC).	Improved redundancy and reduced ATWS frequency.	ATWS	1
133	Install an ATWS sized filtered containment vent to remove decay heat.	Increased ability to remove reactor heat from ATWS events.	ATWS	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
134	Revise procedure to bypass MSIV isolation in turbine trip ATWS scenarios.	Affords operators more time to perform actions. Discharge of a substantial fraction of steam to the main condenser (i.e., as opposed to into the primary containment) affords the operator more time to perform actions (e.g., SLC injection, lower water level, depressurize RPV) than if the main condenser was unavailable, resulting in lower human error probabilities.	ATWS	1
135	Revise procedure to allow override of low pressure core injection during an ATWS event.	Allows immediate control of low pressure core injection. On failure of high pressure core injection and condensate, some plants direct reactor depressurization followed by five minutes of automatic low pressure core injection.	ATWS	1
136	Install motor generator set trip breakers in control room.	Reduced frequency of core damage due to an ATWS.	ATWS	1
137	Provide capability to remove power from the bus powering the control rods.	Decreased time required to insert control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	ATWS	1
138	Improve inspection of rubber expansion joints on main condenser.	Reduced frequency of internal flooding due to failure of circulating water system expansion joints.	Internal Flooding	1
139	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment.	Prevents flood propagation.	Internal Flooding	1
140	Increase seismic ruggedness of plant components.	Increased availability of necessary plant equipment during and after seismic events.	Seismic Risk	1
141	Provide additional restraints for CO2 tanks.	Increased availability of fire protection given a seismic event.	Seismic Risk	1
142	Replace mercury switches in fire protection system.	Decreased probability of spurious fire suppression system actuation.	Fire Risk	1
143	Upgrade fire compartment barriers.	Decreased consequences of a fire.	Fire Risk	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
144	Install additional transfer and isolation switches.	Reduced number of spurious actuations during a fire.	Fire Risk	1
145	Enhance fire brigade awareness.	Decreased consequences of a fire.	Fire Risk	1
146	Enhance control of combustibles and ignition sources.	Decreased fire frequency and consequences.	Fire Risk	1
147	Install digital large break LOCA protection system.	Reduced probability of a large break LOCA (a leak before break).	Other	1
148	Enhance procedures to mitigate large break LOCA.	Reduced consequences of a large break LOCA.	Other	1
149	Install computer aided instrumentation system to assist the operator in assessing post-accident plant status.	Improved prevention of core melt sequences by making operator actions more reliable.	Other	1
150	Improve maintenance procedures.	Improved prevention of core melt sequences by increasing reliability of important equipment.	Other	1
151	Increase training and operating experience feedback to improve operator response.	Improved likelihood of success of operator actions taken in response to abnormal conditions.	Other	1
152	Develop procedures for transportation and nearby facility accidents.	Reduced consequences of transportation and nearby facility accidents.	Other	1
153	Install secondary side guard pipes up to the main steam isolation valves.	Prevents secondary side depressurization should a steam line break occur upstream of the main steam isolation valves. Also guards against or prevents consequential multiple steam generator tube ruptures following a main steam line break event.	Other	1
154	Provide Beaver Valley Units 1 and 2 with 4,160 V Bus Crosstie Capability	Adds a success path for blackout on Unit 2 when both Unit 1 diesel generators work, and vice versa	AC/DC	A
155	Reactor Trip breaker failure , Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	ATWS	A

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
156	Operate plant with all PORV block valves open or provide procedures to open block valves when Main Feedwater is lost.	Increased pressure relief capacity to prevent reactor vessel rupture during ATWS.	ATWS	A
157	Loss of Emergency Switchgear Room HVAC , Enhanced Loss of HVAC Procedures	Confidence that operators will prevent thermal damage to switchgear	HVAC	A
158	RCP Seal Cooling for Station Blackout, Potential modifications under review	Reduced frequency of RCP seal LOCA resulting from blackout	Cooling Water	A
159	Battery Capacity for steam generator level instruments for station blackout, Enhance procedures on shedding loads or using portable battery chargers. One train of the battery chargers will be powered from the site operable emergency diesel generator once the SBO unit cross-tie modification is complete.	Extended operating time for steam generator level instruments for less of all AC power scenarios	AC/DC	A
160	Pressurizer PORV sticking open after loss of offsite power, Eliminate challenge by defeating the 100% load rejection capability.	Reduced frequency of pressurizer PORV sticking open	Core Cooling	A
161	Fast 4,160 V Bus Transfer Failure, Explicit Procedure and Training on breaker repair or change out	Reduced frequency that breaker failures will challenge diesel generators	AC/DC	A
162	Provide a dedicated diesel driven fire water pump with supply tank to provide an additional source of water for SG tube coverage during SGTR events.	This would eliminate the LERF category and reduce all SGTR events to Small Early Releases.	Containment Bypass	C
163	Modify Loss of DC AOP to proceduralize the use of backup battery chargers.	Provide better reliability of the DC busses.	AC/DC	C
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	Containment Bypass	C
165	Install an independent RCP Seal Injection system.	Reduce frequency of RCP seal failure.	Cooling Water	C
166	Provide additional emergency 125V DC battery capability.	Better coping for long term station blackouts	AC/DC	C
167	Increase the seismic ruggedness of the emergency 125V DC battery block walls	Reduce failure of batteries due to seismic induced failure of battery room block walls.	Seismic Risk	C
168	Install fire barriers for HVAC fans in the cable spreading room	Eliminate failure of fire propagating from one fan to another.	Fire Risk	C
169	Improve operator performance. Operator starts Aux RW pump given offsite power is available.	One of top 10 operator actions, OPRWA1	Human Reliability	D

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
170	Improve operator performance. Operator starts portable fans & open doors in emergency switchgear room	One of top 10 operator actions, OPRWBV3	Human Reliability	D
171	Improve operator performance. Operator initiates Safety Injection	One of top 10 operator actions, OPROS6	Human Reliability	D
172	Improve operator performance. Operator initiates bleed and feed cooling given failure of prior actions to restore feedwater systems.	One of top 10 operator actions, OPROB2	Human Reliability	D
173	Improve operator performance. Operator initiates makeup of RWST	One of top 10 operator actions, OPRWM1	Human Reliability	D
174	Improve operator performance. Operator trips RCPs during loss of CCR.	One of top 10 operator actions, OPROC1	Human Reliability	D
175	Improve operator performance. Operator initiates depressurization of RCS given a general transient initiating event.	One of top 10 operator actions, OPROD2	Human Reliability	D
176	Improve operator performance. Operator initiates depressurization of RCS given a SGTR event.	One of top 10 operator actions, OPROD1	Human Reliability	D
177	Improve operator performance. Operator initiates cooldown and depressurization of RCS given a Small LOCA and failure of HHSI.	One of top 10 operator actions, OPRCD6	Human Reliability	D
178	Improve operator performance. Operator aligns hot leg recirculation.	One of top 10 operator actions, OPRLR1	Human Reliability	D
179	Emergency 125V DC battery room block walls Seismic concern from IPEEE.	Reevaluate block wall fragility, reinforce block walls, or shield batteries.	Seismic Risk	B
180	Reroute River Water pump power cable	IPEEE issue with CV-3 fire.	Fire Risk	B
181	Refine Emergency Switchgear room heatup analysis to provide additional time margin.	IPEEE fire issue for CS-1 fire, SW corner.	Fire Risk	B
182	Reroute CCR pump or HHSI suction MOV cables.	IPEEE fire issue for PA-1 fire.	Fire Risk	B
183	Reroute river water or auxiliary river water pump power and control cables	IPEEE fire issue for CS-1 fire, NE corner.	Fire Risk	B
184	Reroute river water or auxiliary river water pump power and control cables	IPEEE fire issue for NS-1 fire, south wall.	Fire Risk	B
185	Install Westinghouse RCP Shutdown seals to work with high temperature O-Rings.	Reduced seal LOCA probability	Cooling Water	F
186	Add guidance to the SAMG to consider post-accident cross-tie of the two unit containments through the gaseous waste system.	Reduce or prevent the release of radionuclides as a result of containment failure.	Containment	E
187	Increase seismic ruggedness of the ERF Substation batteries. This applies to the battery rack only and not the entire structure.	Increased reliability of the ERF diesel following seismic events	Seismic Risk	F

Table 5.6-1 List of SAMA Candidates (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
188	Install a cross-tie between the Unit 1 and Unit 2 RWST.	Increased availability of the RWST for injection.	Core Cooling	E
189	Provide Diesel backed power for the fuel pool purification pumps and valves used for makeup to the RWST.	Increased availability of the RWST during loss of offsite power and station blackout events.	Core Cooling	E

Note 1: The source references are:

1 NEI 05-01 (Reference 24)
A IPE (Reference 2)
B IPEEE (Reference 3)
C Beaver Valley Power Station ELT 2004 Strategic Action Plan - Safe Plant Operations. (Reference 39)
D BV1REV4 PRA (Reference 27)
E NISYS-1092-C006 (Reference 37).
F Undocumented conversations/Interviews with site personnel.

6 PHASE I ANALYSIS

A preliminary screening of the complete list of SAMA candidates was performed to limit the number of SAMAs for which detailed analysis in Phase II was necessary. The screening criteria used in the Phase I analysis are described below.

- ***Screening Criterion A - Not Applicable***: If a SAMA candidate did not apply to the Beaver Valley Unit 1 plant design, it was not retained.
- ***Screening Criterion B - Already Implemented or Intent Met***: If a SAMA candidate had already been implemented at the Beaver Valley Unit 1 or the intent of the candidate is met, it was not retained.
- ***Screening Criterion C - Combined***: If a SAMA candidate was similar in nature and could be combined with another SAMA candidate to develop a more comprehensive or plant-specific SAMA candidate, only the combined SAMA candidate was retained.
- ***Screening Criterion D - Excessive Implementation Cost***: If a SAMA required extensive changes that will obviously exceed the maximum benefit (Section 4.5), even without an implementation cost estimate, it was not retained.
- ***Screening Criterion E - Very Low Benefit***: If a SAMA from an industry document was related to a non-risk significant system for which change in reliability is known to have negligible impact on the risk profile, it was not retained. (No SAMAs were screened using this criterion.)

Table 6-1 presents the list of Phase I SAMA candidates and provides the disposition of each candidate along with the applicable screening criterion associated with each candidate. Those candidates that have not been screened by application of these criteria are evaluated further in the Phase II analysis (Section 7). It can be seen from this table that 126 SAMAs were screened from the analysis during Phase 1 and that 63 SAMAs passed into the next phase of the analysis.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
15	Install tornado protection on gas turbine generator.	Increased availability of on-site AC power.	Yes	A - Not Applicable	Not applicable. Plant does not have gas turbine generator.
27	Revise procedure to allow operators to inhibit automatic vessel depressurization in non-ATWS scenarios.	Extended HPCI and RCIC operation.	Yes	A - Not Applicable	Not applicable. Description of HPCI and RCIC use implies BWR item.
35	Throttle low pressure injection pumps earlier in medium or large-break LOCAs to maintain reactor water storage tank inventory.	Extended reactor water storage tank capacity.	Yes	A - Not Applicable	Per Expert Panel: LHI only used in LBLOCA sequences, throttling not considered. Long-term cooling is sump recirc.
38	Change the in-containment reactor water storage tank suction from four check valves to two check and two air-operated valves.	Reduced common mode failure of injection paths.	Yes	A - Not Applicable	Not Applicable. Beaver Valley suction of different design.
52	Provide hardware connections to allow another essential raw cooling water system to cool charging pump seals.	Reduced effect of loss of component cooling water by providing a means to maintain the charging pump seal injection following a loss of normal cooling water.	Yes	A - Not Applicable	Not Applicable per Expert Panel - Charging pumps seals do not require cooling.
57	Use existing hydro test pump for reactor coolant pump seal injection.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout, unless an alternate power source is used..	Yes	A - Not Applicable	Cannot be implemented due to design limitations. The pressure pulses from the positive displacement pump will damage the seal, leading to seal failure.
60	Prevent makeup pump flow diversion through the relief valves.	Reduced frequency of loss of reactor coolant pump seal cooling if spurious high pressure injection relief valve opening creates a flow diversion large enough to prevent reactor coolant pump seal injection.	Yes	A - Not Applicable	Expert Panel: No relief valves on applicable section of piping.
62	Implement procedures to stagger high pressure safety injection pump use after a loss of service water.	Extended high pressure injection prior to overheating following a loss of service water.	Yes	A - Not Applicable	Due to the estimated time of 12 minutes for pump failure following loss of lube oil cooling and the restricted start duty times of 45 minutes between starts this is not considered a viable option.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
63	Use fire prevention system pumps as a backup seal injection and high pressure makeup source.	Reduced frequency of reactor coolant pump seal LOCA.	Yes	A - Not Applicable	Not applicable. Fire pumps do not have sufficient discharge pressure for high pressure makeup source.
69	Install manual isolation valves around auxiliary feedwater turbine-driven steam admission valves.	Reduced dual turbine-driven pump maintenance unavailability.	Yes	A - Not Applicable	Not Applicable. Beaver Valley does not have dual turbine design.
76	Change failure position of condenser makeup valve if the condenser makeup valve fails open on loss of air or power.	Allows greater inventory for the auxiliary feedwater pumps by preventing condensate storage tank flow diversion to the condenser.	Yes	A - Not Applicable	Not applicable. Condenser makeup valve fails closed.
84	Create ability to switch emergency feedwater room fan power supply to station batteries in a station blackout.	Continued fan operation in a station blackout.	Yes	A - Not Applicable	TDAFW pump rated for high temp. No backup ventilation is needed.
105	Delay containment spray actuation after a large LOCA.	Extended reactor water storage tank availability.	Yes	A - Not Applicable	Delaying the containment spray actuation following a large LOCA, would potentially result in exceeding containment design pressure and/or temperature.
108	Install an independent power supply to the hydrogen control system using either new batteries, a non-safety grade portable generator, existing station batteries, or existing AC/DC independent power supplies, such as the security system diesel.	Reduced hydrogen detonation potential.	Yes	A - Not Applicable	Hydrogen recombiners previously abandoned in-place.
109	Install a passive hydrogen control system.	Reduced hydrogen detonation potential.	Yes	A - Not Applicable	Hydrogen recombiners previously abandoned in-place.
134	Revise procedure to bypass MSIV isolation in turbine trip ATWS scenarios.	Affords operators more time to perform actions. Discharge of a substantial fraction of steam to the main condenser (i.e., as opposed to into the primary containment) affords the operator more time to perform actions (e.g., SLC injection, lower water level, depressurize RPV) than if the main condenser was unavailable, resulting in lower human error probabilities.	Yes	A - Not Applicable	Expert Panel - Determined this is a BWR issue. Additionally, MSIVs cannot be opened once closed.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
135	Revise procedure to allow override of low pressure core injection during an ATWS event.	Allows immediate control of low pressure core injection. On failure of high pressure core injection and condensate, some plants direct reactor depressurization followed by five minutes of automatic low pressure core injection.	Yes	A - Not Applicable	Not applicable. This should be limited to BWR ATWS response.
139	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment.	Prevents flood propagation.	Yes	A - Not Applicable	No internal flooding sources of any risk significance identified.
140	Increase seismic ruggedness of plant components.	Increased availability of necessary plant equipment during and after seismic events.	Yes	A - Not Applicable	Specific identified items addressed in other SAMAs
141	Provide additional restraints for CO2 tanks.	Increased availability of fire protection given a seismic event.	Yes	A - Not Applicable	Seismic PRA and walkdowns did not identify this as a contributor.
160	Pressurizer PORV sticking open after loss of offsite power, Eliminate challenge by defeating the 100% load rejection capability.	Reduced frequency of pressurizer PORV sticking open	Yes	A - Not Applicable	Turbine trip above 49% power results in a direct reactor trip. BV does not have 100% load reject capability.
162	Provide a dedicated diesel driven fire water pump with supply tank to provide an additional source of water for SG tube coverage during SGTR events.	This would eliminate the LERF category and reduce all SGTR events to Small Early Releases.	Yes	A - Not Applicable	Not applicable. 2004 Strategic Action Plan identified this SAMA as only applicable to Unit 2.
185	Install Westinghouse RCP Shutdown seals to work with high temperature O-Rings.	Reduced seal LOCA probability	Yes	A - Not Applicable	Not applicable. This seal modification is not available.
3	Add additional battery charger or portable, diesel-driven battery charger to existing DC system.	Improved availability of DC power system.	Yes	B - Intent Met	Intent Met, Battery Chargers are dual charger units with only one side normally in operation.
7	Add an automatic feature to transfer the 120V vital AC bus from normal to standby power.	Increased availability of the 120 V vital AC bus.	Yes	B - Intent Met	Intent met, part of the UPS design.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
8	Increase training on response to loss of two 120V AC buses which causes inadvertent actuation signals.	Improved chances of successful response to loss of two 120V AC buses.	Yes	B - Intent Met	Loss of a single 120 VAC bus will induce transient. Procedures and training exist for operator response to loss of vital bus. If loss of two buses occurs, operators will implement both procedures.
10	Revise procedure to allow bypass of diesel generator trips.	Extended diesel generator operation.	Yes	B - Intent Met	Intent met. All non-essential EDG trips are bypassed upon emergency start.
11	Improve 4.16-kV bus cross-tie ability.	Increased availability of on-site AC power.	Yes	B - Intent Met	Intent met. Modifications installed.
12	Create AC power cross-tie capability with other unit (multi-unit site)	Increased availability of on-site AC power.	Yes	B - Intent Met	Intent met. Modifications installed.
16	Improve uninterruptible power supplies.	Increased availability of power supplies supporting front-line equipment.	Yes	B - Intent Met	Intent met. Inverters upgraded.
17	Create a cross-tie for diesel fuel oil (multi-unit site).	Increased diesel generator availability.	Yes	B - Intent Met	Intent Met. A fuel oil cross-tie does not exist between the units. Unit 1 does have redundant fuel oil transfer pumps in each train and a cross-tie between the Unit 1 trains. Unit 1 also has a fuel oil receiving tank capable of transferring fuel to either train.
18	Develop procedures for replenishing diesel fuel oil.	Increased diesel generator availability.	Yes	B - Intent Met	Intent met. Procedure exists.
19	Use fire water system as a backup source for diesel cooling.	Increased diesel generator availability.	Yes	B - Intent Met	Intent met. Procedure exists.
20	Add a new backup source of diesel cooling.	Increased diesel generator availability.	Yes	B - Intent Met	Intent met. Cross-connections and backups available.
21	Develop procedures to repair or replace failed 4 KV breakers.	Increased probability of recovery from failure of breakers that transfer 4.16 kV non-emergency buses from unit station service transformers.	Yes	B - Intent Met	Intent met - Existing procedures implement replacement. Spare breaker internals are available near the required locations.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
22	In training, emphasize steps in recovery of off-site power after an SBO.	Reduced human error probability during off-site power recovery.	Yes	B - Intent Met	Intent met. Included in training.
23	Develop a severe weather conditions procedure.	Improved off-site power recovery following external weather-related events.	Yes	B - Intent Met	Intent met. Procedure exists.
30	Improve ECCS suction strainers.	Enhanced reliability of ECCS suction.	Yes	B - Intent Met	Sump improvements being installed with a phased implementation process IAW GL 2004-02.
31	Add the ability to manually align emergency core cooling system recirculation.	Enhanced reliability of ECCS suction.	Yes	B - Intent Met	Intent met. Automatic with procedural manual backup,
32	Add the ability to automatically align emergency core cooling system to recirculation mode upon refueling water storage tank depletion.	Enhanced reliability of ECCS suction.	Yes	B - Intent Met	Intent met. Automatic with procedural manual backup,
33	Provide hardware and procedure to refill the reactor water storage tank once it reaches a specified low level.	Extended reactor water storage tank capacity in the event of a steam generator tube rupture (or other LOCAs challenging RWST capacity) .	Yes	B - Intent Met	Intent met. Procedure and connections exist.
36	Emphasize timely recirculation alignment in operator training.	Reduced human error probability associated with recirculation failure.	Yes	B - Intent Met	Intent met. Included in training.
40	Provide capability for remote, manual operation of secondary side pilot-operated relief valves in a station blackout.	Improved chance of successful operation during station blackout events in which high area temperatures may be encountered (no ventilation to main steam areas).	Yes	B - Intent Met	Intent met. Procedure exists and valves can be operated with hydraulic operator.
42	Make procedure changes for reactor coolant system depressurization.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	Yes	B - Intent Met	Intent met. Procedure exists.
43	Add redundant DC control power for SW pumps.	Increased availability of SW.	Yes	B - Intent Met	Swing Pump fulfills this function. Alternate river water pumps can be aligned to either header.
44	Replace ECCS pump motors with air-cooled motors.	Elimination of ECCS dependency on component cooling system.	Yes	B - Intent Met	Intent met. Per Expert Panel ECCS pump motors are air cooled.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
45	Enhance procedural guidance for use of cross-tied component cooling or service water pumps.	Reduced frequency of loss of component cooling water and service water.	Yes	B - Intent Met	Intent met. Procedures exist.
46	Add a service water pump.	Increased availability of cooling water.	Yes	B - Intent Met	Intent met. The alternate intake facility fulfills this function. An installed spare service water pump that can be aligned to either bus on either loop.
47	Enhance the screen wash system.	Reduced potential for loss of SW due to clogging of screens.	Yes	B - Intent Met	Intent met. Alternate Intake Facility. Alternate intake facility provides redundancy, there is a PM and monitoring program in place for the screens and screen wash system.
49	Enhance loss of component cooling water (or loss of service water) procedures to facilitate stopping the reactor coolant pumps.	Reduced potential for reactor coolant pump seal damage due to pump bearing failure.	Yes	B - Intent Met	Intent met. EOPs also direct operators to stop RCPs on loss of seal cooling.
50	Enhance loss of component cooling water procedure to underscore the desirability of cooling down the reactor coolant system prior to seal LOCA.	Reduced probability of reactor coolant pump seal failure.	Yes	B - Intent Met	Intent met. Procedures exist.
51	Additional training on loss of component cooling water.	Improved success of operator actions after a loss of component cooling water.	Yes	B - Intent Met	Intent met. Loss of component cooling water already included in the training program.
53	On loss of essential raw cooling water, proceduralize shedding component cooling water loads to extend the component cooling water heat-up time.	Increased time before loss of component cooling water (and reactor coolant pump seal failure) during loss of essential raw cooling water sequences.	Yes	B - Intent Met	Intent met. Procedure exists.
58	Install improved reactor coolant pump seals.	Reduced likelihood of reactor coolant pump seal LOCA.	Yes	B - Intent Met	Intent met. New design RCP seals installed. See also SAMAs 158 & 185.
59	Install an additional component cooling water pump.	Reduced likelihood of loss of component cooling water leading to a reactor coolant pump seal LOCA.	Yes	B - Intent Met	Installed spare CCR pump can be run off either bus.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
61	Change procedures to isolate reactor coolant pump seal return flow on loss of component cooling water, and provide (or enhance) guidance on loss of injection during seal LOCA.	Reduced frequency of core damage due to loss of seal cooling.	Yes	B - Intent Met	Intent met. Procedure exists.
66	Create ability for emergency connection of existing or new water sources to feedwater and condensate systems.	Increased availability of feedwater.	Yes	B - Intent Met	Intent met. Per Expert Panel - AFW has backup from river water, dedicated AFW pump has suction from two separate demin water tanks.
67	Install an independent diesel for the condensate storage tank makeup pumps.	Extended inventory in CST during an SBO.	Yes	B - Intent Met	Intent met. Per Expert Panel - Dedicated AFW pump is backed by ERF diesel generator and has suction from two separate demin water tanks.
68	Add a motor-driven feedwater pump.	Increased availability of feedwater.	Yes	B - Intent Met	Intent met. Per Expert Panel - Unit has dedicated motor driven AFW pump with power backup from ERF diesel generator. Feedwater pumps are motor driven.
70	Install accumulators for turbine-driven auxiliary feedwater pump flow control valves.	Eliminates the need for local manual action to align nitrogen bottles for control air following a loss of off-site power.	Yes	B - Intent Met	Implemented - TDAFW has no flow control valve. The min-flow valve is air-operated and the supply air is diesel backed. The motor driven trains have MOVs that can be manually manipulated.
71	Install a new condensate storage tank (auxiliary feedwater storage tank).	Increased availability of the auxiliary feedwater system.	Yes	B - Intent Met	Intent met. Per Expert Panel - Dedicated AFW pump is backed by ERF diesel generator and has suction from separate demin water tanks.
72	Modify the turbine-driven auxiliary feedwater pump to be self-cooled.	Improved success probability during a station blackout.	Yes	B - Intent Met	Intent met. Per Expert Panel - TDAFW is self cooled.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
73	Proceduralize local manual operation of auxiliary feedwater system when control power is lost.	Extended auxiliary feedwater availability during a station blackout. Also provides a success path should auxiliary feedwater control power be lost in non-station blackout sequences.	Yes	B - Intent Met	Intent met. During an SBO, no manual actions are needed for TDAFW operation.
74	Provide hookup for portable generators to power the turbine-driven auxiliary feedwater pump after station batteries are depleted.	Extended auxiliary feedwater availability.	Yes	B - Intent Met	ERF diesel generator can supply U1 dedicated AFW pump. TDAFW pump does not require DC power.
75	Use fire water system as a backup for steam generator inventory.	Increased availability of steam generator water supply.	Yes	B - Intent Met	Intent met. Service Water and River Water systems can be used as backup water source to AFW. Diesel fire water pump can be cross-tied to RW.
78	Modify the startup feedwater pump so that it can be used as a backup to the emergency feedwater system, including during a station blackout scenario.	Increased reliability of decay heat removal.	Yes	B - Intent Met	Intent met. The U1 dedicated AFW pump provides the same function; it is powered from the ERF diesel.
79	Replace existing pilot-operated relief valves with larger ones, such that only one is required for successful feed and bleed.	Increased probability of successful feed and bleed.	Yes	B - Intent Met	Beaver Valley has three pressurizer PORVs, only one is required for successful feed and bleed.
80	Provide a redundant train or means of ventilation.	Increased availability of components dependent on room cooling.	Yes	B - Intent Met	Switchgear room cooling system. Portable fans are available (not staged in switchgear room, but are nearby) as a backup and operators are trained on implementing the temporary ventilation system. Same for EDG Building HVAC.
81	Add a diesel building high temperature alarm or redundant louver and thermostat.	Improved diagnosis of a loss of diesel building HVAC.	Yes	B - Intent Met	No high temperature alarm, but alarm does exist for HVAC system trouble/trip. Portable fans are available for backup.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
82	Stage backup fans in switchgear rooms.	Increased availability of ventilation in the event of a loss of switchgear ventilation.	Yes	B - Intent Met	Intent met. Fans are not staged in switchgear room, but are nearby.
83	Add a switchgear room high temperature alarm.	Improved diagnosis of a loss of switchgear HVAC.	Yes	B - Intent Met	No high temperature alarm, but multiple alarms for fan trips. Backup fans are staged and a procedure exists for implementing temporary ventilation. Analysis shows long time available to implement temporary ventilation. Operators are trained on the procedure for temporary ventilation.
85	Provide cross-unit connection of uninterruptible compressed air supply.	Increased ability to vent containment using the hardened vent.	Yes	B - Intent Met	BV1 has a third train of station air supplied from diesel air compressor although the containment vent is not air operated.
86	Modify procedure to provide ability to align diesel power to more air compressors.	Increased availability of instrument air after a LOOP.	Yes	B - Intent Met	Intent met. Diesel powered air compressor installed.
87	Replace service and instrument air compressors with more reliable compressors which have self-contained air cooling by shaft driven fans.	Elimination of instrument air system dependence on service water cooling.	Yes	B - Intent Met	Third train of station air supplied from diesel air compressor; this compressor is self cooled.
88	Install nitrogen bottles as backup gas supply for safety relief valves.	Extended SRV operation time.	Yes	B - Intent Met	Implemented for the PORVs (accumulators), steam generators ADV's have manual operation capability; pressurizer and steam generator Safety Valves do not require air.
90	Create a reactor cavity flooding system.	Enhanced debris cool ability, reduced core concrete interaction, and increased fission product scrubbing.	Yes	B - Intent Met	This is being implemented at BV1 using existing systems as directed by SAMGs.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
92	Use the fire water system as a backup source for the containment spray system.	Improved containment spray capability.	Yes	B - Intent Met	Intent met. Procedures exist.
93	Install an unfiltered, hardened containment vent.	Increased decay heat removal capability for non-ATWS events, without scrubbing released fission products.	Yes	B - Intent Met	SAMG guidance contains guidance for a number of containment venting paths. Although not a dedicated hardened vent, redundant and separate venting paths exist.
95	Enhance fire protection system and standby gas treatment system hardware and procedures.	Improved fission product scrubbing in severe accidents.	Yes	B - Intent Met	Intent met. Included in SAMG.
103	Institute simulator training for severe accident scenarios.	Improved arrest of core melt progress and prevention of containment failure.	Yes	B - Intent Met	Intent met. Already included in the training program.
106	Install automatic containment spray pump header throttle valves.	Extended time over which water remains in the reactor water storage tank, when full containment spray flow is not needed.	Yes	B - Intent Met	Implemented IAW EOPs, not automatic, but manual as directed by procedures.
114	Install self-actuating containment isolation valves.	Reduced frequency of isolation failure.	Yes	B - Intent Met	Intent met. AOV, MOV and CV containment isolation valves; those that are required to close are AOVs and fail closed on loss-of-air, or are administratively controlled closed.
115	Locate residual heat removal (RHR) inside containment	Reduced frequency of ISLOCA outside containment.	Yes	B - Intent Met	Intent met. RHR pumps are located inside containment.
116	Ensure ISLOCA releases are scrubbed. One method is to plug drains in potential break areas so that break point will be covered with water.	Scrubbed ISLOCA releases.	Yes	B - Intent Met	Break flow is expected to submerge the break location; in addition, the fission product releases would pass through building ventilation which is filtered through the supplemental leak collection and release system.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
117	Revise EOPs to improve ISLOCA identification.	Increased likelihood that LOCAs outside containment are identified as such. A plant had a scenario in which an RHR ISLOCA could direct initial leakage back to the pressurizer relief tank, giving indication that the LOCA was inside containment.	Yes	B - Intent Met	Intent met. EOPs provide guidance to eliminate other routes.
120	Replace steam generators with a new design.	Reduced frequency of steam generator tube ruptures.	Yes	B - Intent Met	Intent met. Steam Generators replaced with updated design with orifice on discharge to limit steam line rupture. Upgraded tube and tubesheet design.
123	Proceduralize use of pressurizer vent valves during steam generator tube rupture sequences.	Backup method to using pressurizer sprays to reduce primary system pressure following a steam generator tube rupture.	Yes	B - Intent Met	Intent met. Procedure exists.
124	Provide improved instrumentation to detect steam generator tube ruptures, such as Nitrogen-16 monitors).	Improved mitigation of steam generator tube ruptures.	Yes	B - Intent Met	Intent met. N-16 monitors installed.
127	Revise emergency operating procedures to direct isolation of a faulted steam generator.	Reduced consequences of a steam generator tube rupture.	Yes	B - Intent Met	Intent met by alternate means. Procedure EOP E-2 directs operators to isolate faulted SGs by closing all actuated or manual valves associated with the affected SG. SAMA 164 will enhance procedures to provide steps to isolate any stuck-open safety valves on a ruptured SG.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
128	Direct steam generator flooding after a steam generator tube rupture, prior to core damage.	Improved scrubbing of steam generator tube rupture releases.	Yes	B - Intent Met	Intent met by alternate means. Procedure EOP E-3 directs operators to feed ruptured SGs if the narrow range level is below 12%. SAMA 164, will enhance procedures to provide steps to; consider feeding a faulted-ruptured SG to provide continuous scrubbing (by maintaining ~12% to 50% narrow range SG level by throttling AFW flow to the ruptured SG), isolate any stuck-open safety valves on a ruptured SG, or close the RCS Loop Stop Valves on the ruptured SG to terminate or minimize the release.
132	Provide an additional control system for rod insertion (e.g., AMSAC).	Improved redundancy and reduced ATWS frequency.	Yes	B - Intent Met	Intent met. AMSAC installed.
138	Improve inspection of rubber expansion joints on main condenser.	Reduced frequency of internal flooding due to failure of circulating water system expansion joints.	Yes	B - Intent Met	Implemented - Program exists to inspect and replace expansion joints in the turbine building. No internal flooding sources of any risk significance identified.
142	Replace mercury switches in fire protection system.	Decreased probability of spurious fire suppression system actuation.	Yes	B - Intent Met	Intent met. Remaining mercury switches will not cause spurious suppression system actuations affecting plant equipment.
144	Install additional transfer and isolation switches.	Reduced number of spurious actuations during a fire.	Yes	B - Intent Met	Current fire protection safe shutdown procedures intentionally de-energize circuits to reduce the number of spurious actuations.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
145	Enhance fire brigade awareness.	Decreased consequences of a fire.	Yes	B - Intent Met	Fire brigade training and procedures meet current industry practices.
146	Enhance control of combustibles and ignition sources.	Decreased fire frequency and consequences.	Yes	B - Intent Met	Intent met. Procedure exists.
148	Enhance procedures to mitigate large break LOCA.	Reduced consequences of a large break LOCA.	Yes	B - Intent Met	Intent met. Owner's Group recommendations implemented.
149	Install computer aided instrumentation system to assist the operator in assessing post-accident plant status.	Improved prevention of core melt sequences by making operator actions more reliable.	Yes	B - Intent Met	Safety Parameter Display System installed.
150	Improve maintenance procedures.	Improved prevention of core melt sequences by increasing reliability of important equipment.	Yes	B - Intent Met	Intent met. Maintenance procedures are written IAW current industry standards and guidance.
151	Increase training and operating experience feedback to improve operator response.	Improved likelihood of success of operator actions taken in response to abnormal conditions.	Yes	B - Intent Met	Training and operator experience feedback meets current industry standards and practices.
152	Develop procedures for transportation and nearby facility accidents.	Reduced consequences of transportation and nearby facility accidents.	Yes	B - Intent Met	Intent met but will be reevaluated (nearby industrial facilities) because the potential for impacts of the expanded propane storage facility being modified across the river from BV.
154	Provide Beaver Valley Units 1 and 2 with 4,160 V Bus Crosstie Capability	Adds a success path for blackout on Unit 2 when both Unit 1 diesel generators work, and vice versa	Yes	B - Intent Met	Cross-Tie installed
156	Operate plant with all PORV block valves open or provide procedures to open block valves when Main Feedwater is lost.	Increased pressure relief capacity to prevent reactor vessel rupture during ATWS.	Yes	B - Intent Met	Intent met. Normal operational alignment has all 3 block valves open. The configuration risk management program limits the amount of time the PORV block valves can remain closed..
157	Loss of Emergency Switchgear Room HVAC , Enhanced Loss of HVAC Procedures	Confidence that operators will prevent thermal damage to switchgear	Yes	B - Intent Met	Intent met. Procedure exists and equipment is staged.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
158	RCP Seal Cooling for Station Blackout, Potential modifications under review	Reduced frequency of RCP seal LOCA resulting from blackout	Yes	B - Intent Met	Intent met. High temperature seals installed.
159	Battery Capacity for steam generator level instruments for station blackout, Enhance procedures on shedding loads or using portable battery chargers. One train of the battery chargers will be powered from the site operable emergency diesel generator once the SBO unit cross-tie modification is complete.	Extended operating time for steam generator level instruments for less of all AC power scenarios	Yes	B - Intent Met	BVPS has committed to implement this SAMA using an alternate mitigation strategy using a portable generator to power the SG level instrumentation by the end of 2007.
161	Fast 4,160 V Bus Transfer Failure, Explicit Procedure and Training on breaker repair or change out	Reduced frequency that breaker failures will challenge diesel generators	Yes	B - Intent Met	Intent met - Existing procedures implement replacement. Spare breaker internals are available near the required locations.
163	Modify Loss of DC AOP to proceduralize the use of backup battery chargers.	Provide better reliability of the DC busses.	Yes	B - Intent Met	Intent met. Procedure exists.
181	Refine Emergency Switchgear room heatup analysis to provide additional time margin.	IPEEE fire issue for CS-1 fire, SW corner.	Yes	B - Intent Met	This fire impacts the switchgear ventilation fans and is already identified in SAMAs Per Expert Panel -the switchgear room heatup analysis has been performed and shows five hours available to install backup ventilation.
9	Provide an additional diesel generator.	Increased availability of on-site emergency AC power.	Yes	C - Combined	Intent met. Reference SAMA 154.
143	Upgrade fire compartment barriers.	Decreased consequences of a fire.	Yes	C - Combined	Retain for Phase II analysis. See also SAMA 168 for same item.
179	Emergency 125V DC battery room block walls Seismic concern from IPEEE.	Reevaluate block wall fragility, reinforce block walls, or shield batteries.	Yes	C - Combined	Retain for Phase II analysis. See also SAMA 167.
24	Bury off-site power lines.	Improved off-site power reliability during severe weather.	Yes	D - Excess Cost	Excessive Implementation Cost

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
34	Provide an in-containment reactor water storage tank.	Continuous source of water to the safety injection pumps during a LOCA event, since water released from a breach of the primary system collects in the in-containment reactor water storage tank, and thereby eliminates the need to realign the safety injection pumps for long-term post-LOCA recirculation.	Yes	D - Excess Cost	Excessive Implementation Cost
77	Provide a passive, secondary-side heat-rejection loop consisting of a condenser and heat sink.	Reduced potential for core damage due to loss-of-feedwater events.	Yes	D - Excess Cost	Excessive Implementation Cost
91	Install a passive containment spray system.	Improved containment spray capability.	Yes	D - Excess Cost	Excessive Implementation Cost
97	Create a large concrete crucible with heat removal potential to contain molten core debris.	Increased cooling and containment of molten core debris. Molten core debris escaping from the vessel is contained within the crucible and a water cooling mechanism cools the molten core in the crucible, preventing melt-through of the base mat.	Yes	D - Excess Cost	Excessive Implementation Cost
99	Strengthen primary/secondary containment (e.g., add ribbing to containment shell).	Reduced probability of containment over-pressurization.	Yes	D - Excess Cost	Expert Panel >MAB
100	Increase depth of the concrete base mat or use an alternate concrete material to ensure melt-through does not occur.	Reduced probability of base mat melt-through.	Yes	D - Excess Cost	Excessive Implementation Cost
101	Provide a reactor vessel exterior cooling system.	Increased potential to cool a molten core before it causes vessel failure, by submerging the lower head in water.	Yes	D - Excess Cost	Excessive Implementation Cost
102	Construct a building to be connected to primary/secondary containment and maintained at a vacuum.	Reduced probability of containment over-pressurization.	Yes	D - Excess Cost	Excessive Implementation Cost
110	Erect a barrier that would provide enhanced protection of the containment walls (shell) from ejected core debris following a core melt scenario at high pressure.	Reduced probability of containment failure.	Yes	D - Excess Cost	Excessive Implementation Cost

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
121	Increase the pressure capacity of the secondary side so that a steam generator tube rupture would not cause the relief valves to lift.	Eliminates release pathway to the environment following a steam generator tube rupture.	Yes	D - Excess Cost	Excessive Implementation Cost
125	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.	Reduced consequences of a steam generator tube rupture.	Yes	D - Excess Cost	Excessive Implementation Cost
126	Install a highly reliable (closed loop) steam generator shell-side heat removal system that relies on natural circulation and stored water sources	Reduced consequences of a steam generator tube rupture.	Yes	D - Excess Cost	Excessive Implementation Cost
129	Vent main steam safety valves in containment.	Reduced consequences of a steam generator tube rupture.	Yes	D - Excess Cost	Excessive Implementation Cost
1	Provide additional DC battery capacity.	Extended DC power availability during an SBO.	No		Retain for Phase II analysis.
2	Replace lead-acid batteries with fuel cells.	Extended DC power availability during an SBO.	No		Retain for Phase II analysis.
4	Improve DC bus load shedding.	Extended DC power availability during an SBO.	No		Retain for Phase II analysis.
5	Provide DC bus cross-ties.	Improved availability of DC power system.	No		Retain for Phase II analysis. Limited cross-tie capability exists.
6	Provide additional DC power to the 120/240V vital AC system.	Increased availability of the 120 V vital AC bus.	No		Retain for Phase II analysis.
13	Install an additional, buried off-site power source.	Reduced probability of loss of off-site power.	No		Retain for Phase II analysis.
14	Install a gas turbine generator.	Increased availability of on-site AC power.	No		ERF diesel generator has limited ability to power plant loads. Retain for Phase II analysis.
25	Install an independent active or passive high pressure injection system.	Improved prevention of core melt sequences.	No		Retain for Phase II analysis.
26	Provide an additional high pressure injection pump with independent diesel.	Reduced frequency of core melt from small LOCA and SBO sequences.	No		Retain for Phase II analysis.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
28	Add a diverse low pressure injection system.	Improved injection capability.	No		Retain for Phase II analysis.
29	Provide capability for alternate injection via diesel-driven fire pump.	Improved injection capability.	No		Retain for Phase II analysis.
37	Upgrade the chemical and volume control system to mitigate small LOCAs.	For a plant like the Westinghouse AP600, where the chemical and volume control system cannot mitigate a small LOCA, an upgrade would decrease the frequency of core damage.	No		Retain for Phase II analysis.
39	Replace two of the four electric safety injection pumps with diesel-powered pumps.	Reduced common cause failure of the safety injection system. This SAMA was originally intended for the Westinghouse-CE System 80+, which has four trains of safety injection. However, the intent of this SAMA is to provide diversity within the high- and low-pressure safety injections systems.	No		Retain for Phase II analysis.
41	Create a reactor coolant depressurization system.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	No		Retain for Phase II analysis.
48	Cap downstream piping of normally closed component cooling water drain and vent valves.	Reduced frequency of loss of component cooling water initiating events, some of which can be attributed to catastrophic failure of one of the many single isolation valves.	No		Vents and drains are capped with exceptions.
54	Increase charging pump lube oil capacity.	Increased time before charging pump failure due to lube oil overheating in loss of cooling water sequences.	No		Retain for Phase II analysis.
55	Install an independent reactor coolant pump seal injection system, with dedicated diesel.	Reduced frequency of core damage from loss of component cooling water, service water, or station blackout.	No		Retain for Phase II analysis.
56	Install an independent reactor coolant pump seal injection system, without dedicated diesel.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	No		Retain for Phase II analysis.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
64	Implement procedure and hardware modifications to allow manual alignment of the fire water system to the component cooling water system, or install a component cooling water header cross-tie.	Improved ability to cool residual heat removal heat exchangers.	No		Retain for Phase II analysis.
65	Install a digital feed water upgrade.	Reduced chance of loss of main feed water following a plant trip.	No		Retain for Phase II analysis. Digital feedwater not installed and not planned.
89	Improve SRV and MSIV pneumatic components.	Improved availability of SRVs and MSIVs.	No		Retain for Phase II analysis.
94	Install a filtered containment vent to remove decay heat. Option 1: Gravel Bed Filter; Option 2: Multiple Venturi Scrubber	Increased decay heat removal capability for non-ATWS events, with scrubbing of released fission products.	No		SAMG guidance contains guidance for a number of containment venting paths. Some of these vent paths are filtered. Retain for Phase II analysis.
96	Provide post-accident containment inerting capability.	Reduced likelihood of hydrogen and carbon monoxide gas combustion.	No		Retain for Phase II analysis.
98	Create a core melt source reduction system.	Increased cooling and containment of molten core debris. Refractory material would be placed underneath the reactor vessel such that a molten core falling on the material would melt and combine with the material. Subsequent spreading and heat removal from the vitrified compound would be facilitated, and concrete attack would not occur.	No		Retain for Phase II analysis.
104	Improve leak detection procedures.	Increased piping surveillance to identify leaks prior to complete failure. Improved leak detection would reduce LOCA frequency.	No		Retain for Phase II analysis.
107	Install a redundant containment spray system.	Increased containment heat removal ability.	No		Retain for Phase II analysis.
111	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	Reduced ISLOCA frequency.	No		Retain for Phase II analysis.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
112	Add redundant and diverse limit switches to each containment isolation valve.	Reduced frequency of containment isolation failure and ISLOCAs.	No		Retain for Phase II analysis.
113	Increase leak testing of valves in ISLOCA paths.	Reduced ISLOCA frequency.	No		Retain for Phase II analysis.
118	Improve operator training on ISLOCA coping.	Decreased ISLOCA consequences.	No		Retain for Phase II analysis.
119	Institute a maintenance practice to perform a 100% inspection of steam generator tubes during each refueling outage.	Reduced frequency of steam generator tube ruptures.	No		Retain for Phase II analysis.
122	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture	Enhanced depressurization capabilities during steam generator tube rupture.	No		Retain for Phase II analysis.
130	Add an independent boron injection system.	Improved availability of boron injection during ATWS.	No		Retain for Phase II analysis.
131	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	Improved equipment availability after an ATWS.	No		Retain for Phase II analysis.
133	Install an ATWS sized filtered containment vent to remove decay heat.	Increased ability to remove reactor heat from ATWS events.	No		Retain for Phase II analysis.
136	Install motor generator set trip breakers in control room.	Reduced frequency of core damage due to an ATWS.	No		Retain for Phase II analysis.
137	Provide capability to remove power from the bus powering the control rods.	Decreased time required to insert control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	No		Retain for Phase II analysis. Capability exists outside the control room, but action takes too long to perform.
147	Install digital large break LOCA protection system.	Reduced probability of a large break LOCA (a leak before break).	No		Retain for Phase II analysis.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
153	Install secondary side guard pipes up to the main steam isolation valves.	Prevents secondary side depressurization should a steam line break occur upstream of the main steam isolation valves. Also guards against or prevents consequential multiple steam generator tube ruptures following a main steam line break event.	No		Retain for Phase II analysis.
155	Reactor Trip breaker failure , Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	No		Retain for Phase II analysis. Capability exists outside the control room, but action takes too long to perform.
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	No		Retain for Phase II analysis.
165	Install an independent RCP Seal Injection system.	Reduce frequency of RCP seal failure.	No		Retain for Phase II analysis.
166	Provide additional emergency 125V DC battery capability.	Better coping for long term station blackouts	No		Retain for Phase II analysis.
167	Increase the seismic ruggedness of the emergency 125V DC battery block walls	Reduce failure of batteries due to seismic induced failure of battery room block walls.	No		Retain for Phase II analysis. The block walls have been evaluated and found satisfactory. See also SAMA 179.
168	Install fire barriers for HVAC fans in the cable spreading room	Eliminate failure of fire propagating from one fan to another.	No		Retain for Phase II analysis. See also SAMA 143 for same item.
169	Improve operator performance. Operator starts Aux RW pump given offsite power is available.	One of top 10 operator actions, OPRWA1	No		Retain for Phase II analysis.
170	Improve operator performance. Operator starts portable fans & open doors in emergency switchgear room	One of top 10 operator actions, OPRWBV3	No		Retain for Phase II analysis.
171	Improve operator performance. Operator initiates Safety Injection	One of top 10 operator actions, OPROS6	No		Retain for Phase II analysis.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
172	Improve operator performance. Operator initiates bleed and feed cooling given failure of prior actions to restore feedwater systems.	One of top 10 operator actions, OPROB2	No		Retain for Phase II analysis.
173	Improve operator performance. Operator initiates makeup of RWST	One of top 10 operator actions, OPRWM1	No		Retain for Phase II analysis.
174	Improve operator performance. Operator trips RCPs during loss of CCR.	One of top 10 operator actions, OPROC1	No		Retain for Phase II analysis.
175	Improve operator performance. Operator initiates depressurization of RCS given a general transient initiating event.	One of top 10 operator actions, OPROD2	No		Retain for Phase II analysis.
176	Improve operator performance. Operator initiates depressurization of RCS given a SGTR event.	One of top 10 operator actions, OPROD1	No		Retain for Phase II analysis.
177	Improve operator performance. Operator initiates cooldown and depressurization of RCS given a Small LOCA and failure of HHSI.	One of top 10 operator actions, OPRCD6	No		Retain for Phase II analysis.
178	Improve operator performance. Operator aligns hot leg recirculation.	One of top 10 operator actions, OPRLR1	No		Retain for Phase II analysis.
180	Reroute River Water pump power cable	IPEEE issue with CV-3 fire.	No		Retain for Phase II analysis.
182	Reroute CCR pump or HHSI suction MOV cables.	IPEEE fire issue for PA-1 fire.	No		Retain for Phase II analysis.
183	Reroute river water or auxiliary river water pump power and control cables	IPEEE fire issue for CS-1 fire, NE corner.	No		Retain for Phase II analysis.
184	Reroute river water or auxiliary river water pump power and control cables	IPEEE fire issue for NS-1 fire, south wall.	No		Retain for Phase II analysis.
186	Add guidance to the SAMG to consider post-accident cross-tie of the two unit containments through the gaseous waste system.	Reduce or prevent the release of radionuclides as a result of containment failure.	No		Retain for Phase II analysis.

Table 6-1 BVPS Unit 1 Phase 1 SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	Screened Out Ph 1?	Screening Criterion	Phase I Disposition
187	Increase seismic ruggedness of the ERF Substation batteries. This applies to the battery rack only and not the entire structure.	Increased reliability of the ERF diesel following seismic events	No		Retain for Phase II analysis.
188	Install a cross-tie between the Unit 1 and Unit 2 RWST.	Increased availability of the RWST for injection.	No		Retain for Phase II analysis.
189	Provide Diesel backed power for the fuel pool purification pumps and valves used for makeup to the RWST.	Increased availability of the RWST during loss of offsite power and station blackout events.	No		Retain for Phase II analysis. This SAMA to provide procedure changes and temporary power jumpers.

7 PHASE II SAMA ANALYSIS

A cost-benefit analysis was performed on each of the SAMA candidates remaining after the Phase I screening. The benefit of a SAMA candidate is the difference between the baseline cost of severe accident risk (maximum benefit from Section 4.5) and the cost of severe accident risk with the SAMA implemented (Section 7.1). The cost figure used is the estimated cost to implement the specific SAMA. If the estimated cost of implementation exceeds the benefit of implementation, the SAMA is not cost-beneficial.

Since the SAMA analysis is being performed separately for each Beaver Valley unit, the costs and the benefits are provided on a per-unit basis. If a SAMA candidate is shared by the units, that information is noted in the Phase II SAMA candidate list and it is analyzed in a manner consistent with its applicability to both units.

7.1 SAMA BENEFIT

7.1.1 Severe Accident Risk with SAMA Implemented

Bounding analyses were used to determine the change in risk following implementation of SAMA candidates or groups of similar SAMA candidates. For each analysis case, the Level 1 internal events or Level 2 PRA models were altered to conservatively consider implementation of the SAMA candidate(s). Then, severe accident risk measures were calculated using the same procedure used for the baseline case described in Section 3. The changes made to the PRA models for each analysis case are described in Appendix A.

A “bounding analyses” are exemplified by the following:
LBLOCA
This analysis case was used to evaluate the change in plant risk profile that would be achieved if a digital large break LOCA protection system was installed. Although the proposed change would not completely eliminate the potential for a large break LOCA, a bounding benefit was estimated by removing the large break LOCA initiating event. This analysis case was used to model the benefit of SAMA xx.

DCPWR
This analysis case was used to evaluate plant modifications that would increase the availability of Class 1E DC power (e.g., increased battery capacity or the installation of a diesel-powered generator that would effectively increase battery capacity). Although the proposed SAMAs would not completely eliminate the potential failure, a bounding benefit was estimated by removing the

battery discharge events and battery failure events. This analysis case was used to model the benefit of SAMAs a, b, etc.

The severe accident risk measures were obtained for each analysis case by modifying the baseline model in a simple manner to capture the effect of implementation of the SAMA in a bounding manner. Bounding analyses are very conservative and result in overestimation of the benefit of the candidate analyzed. However, if this bounding assessment yields a benefit that is smaller than the cost of implementation, then the effort involved in refining the PRA modeling approach for the SAMA would be unnecessary because it would only yield a lower benefit result. If the benefit is greater than the cost when modeled in this bounding approach, it is necessary to refine the PRA model of the SAMA to remove conservatism. As a result of this modeling approach, models representing the Phase II SAMAs will not all be at the same level of detail and if any are implemented, the PRA result after implementation of the final installed design will differ from the screening-type analyses done during this evaluation.

7.1.2 Cost of Severe Accident Risk with SAMA Implemented

Using the risk measures determined as described in Section 7.1.1, severe accident impacts in four areas (offsite exposure cost, off-site economic cost, on-site exposure cost, and on-site economic cost) were calculated using the same procedure used for the baseline case described in Section 4. As in Section 4.5, the severe accident impacts were summed to estimate the total cost of severe accident risk with the SAMA implemented.

7.1.3 SAMA Benefit Calculation

The respective SAMA benefit was calculated by subtracting the total cost of severe accident risk with the SAMA implemented from the baseline cost of severe accident risk (maximum benefit from Section 4.5). The estimated benefit for each SAMA candidate is listed in Table 7-1. The calculation of the benefit is performed using an Excel spreadsheet.

7.2 COST OF SAMA IMPLEMENTATION

The final step in the evaluation of the SAMAs is estimating the cost of implementation for comparison with the benefit. For the purpose of this analysis the BVPS staff has estimated that the cost of making a change to a procedure and for conducting the necessary training on a procedure change is expected to exceed **$15,000**. Similarly, the minimum cost associated with development and implementation of an integrated hardware modification package (including post-implementation costs, e.g. training) was assumed to be **$100,000**. These values were used for comparison with the benefit of SAMAs.

The benefits resulting from the bounding estimates presented in the benefit analysis are in some cases rather low. In those cases for which the benefits are so low that it is obvious that the implementation costs would exceed the benefit, a detailed cost estimate was not warranted. Plant staff judgment is applied in assessing whether the benefit approaches the expected implementation costs in many cases.

Plant staff judgment was obtained from an independent, expert panel consisting of senior staff members from the PRA group, the design group, operations and license renewal. This panel reviewed the benefit calculation results and, based upon their experience with developing and implementing modifications at the plant, judged whether a modification could be made to the plant that would be cost beneficial in comparison with the calculated benefit. The purpose of this approach was to minimize the effort expended on detailed cost estimation. The cost estimations provided by the expert panel are included in Table 7-1 along with the conclusions reached for each SAMA evaluated for cost/benefit.

It should be noted that the results of the sensitivities of Section 8 influenced the decisions of whether a SAMA was considered to be potentially cost beneficial. If the benefits calculated in the sensitivity analyses exceeded the estimated cost of the SAMA, it was considered potentially cost beneficial.

7.3 SAMAs WITH SHARED BENEFIT OR COSTS

A number of SAMAs either benefit both BVPS-1 and BVPS-2 or the cost of implementation would be shared by both units. In this case, consideration of the costs and benefits at only one unit is not appropriate.

SAMA 14, installation of a gas turbine generator, would provide benefit for both units. The maximum combined benefit for this SAMA is $ 1.9 million ($400K in Unit 1 and $1,495K in Unit 2). The cost to implement this SAMA is greater than $7 million. Even with the combined benefit, this SAMA is not cost beneficial.

SAMA 187 (Unit 1) and 186 (Unit 2), increase the seismic ruggedness of the ERF Substation batteries, would provide benefit for both units. Currently the ERF diesel generator can provide power to the Unit 1 Dedicated AFW system, but very little equipment on Unit 2. The benefit of this SAMA to Unit 2 is $3.8K compared to the Unit 1 benefit of $525K. The estimated cost for implementing this SAMA is $300K. This SAMA is considered potentially cost beneficial for BVPS-1, but not for BVPS-2.

SAMA 186 (Unit 1) and 190 (Unit 2), provide a containment cross-tie between the units, would provide benefit to both units. However, the result of using this cross-tie to mitigate an event would result in contamination of both units. The cost of cleanup of the opposite unit is not included in the benefit calculation. Due to the high cost of implementation and the impact on the opposite unit, this SAMA is not considered cost beneficial for either unit.

Unit 1 SAMA 188 (RWST cross-tie) would provide a benefit for both units. However, since the Unit 2 RWST is significantly larger than the Unit 1 RWST, the benefit to Unit 2 would be small and was therefore not considered as a SAMA. The high cost of implementation (>$4,000K), therefore, makes this SAMA not cost beneficial (at either unit).

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
1	Provide additional DC battery capacity.	Extended DC power availability during an SBO.	0.00%	0.26%	DC01	Assumed no failure or depletion of DC power system.	$13.9K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
2	Replace lead-acid batteries with fuel cells.	Extended DC power availability during an SBO.	0.00%	0.26%	DC01	Assumed no failure or depletion of DC power system.	$13.9K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
4	Improve DC bus load shedding.	Extended DC power availability during an SBO.	0.00%	0.26%	DC01	Assumed no failure or depletion of DC power system.	$13.9K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
5	Provide DC bus cross-ties.	Improved availability of DC power system.	0.00%	0.26%	DC01	Assumed no failure or depletion of DC power system.	$13.9K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
6	Provide additional DC power to the 120/240V vital AC system.	Increased availability of the 120 V vital AC bus.	0.00%	0.26%	DC01	Assumed no failure or depletion of DC power system.	$13.9K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
13	Install an additional, buried off-site power source.	Reduced probability of loss of off-site power.	1.27%	1.27%	NOLOSP	This case was used to determine the benefit of eliminating all loss of offsite power events, both as the initiating event and subsequent to a different initiating event. This allows evaluation of various possible improvements that could reduce the risk associated with loss of offsite power events. For the purposes of the analysis, a single bounding analysis was performed which assumed that loss of offsite power events do not occur, both as an initiating event and subsequent to a different initiating event.	$73.7K	>$2,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
14	Install a gas turbine generator.	Increased availability of on-site AC power.	11.21%	7.46%	NOSBO	This case is used to determine the benefit of eliminating all Station Blackout events. This allows evaluation of possible improvements related to SBO sequences. For the purpose of the analysis, a single bounding analysis is performed that assumes the Diesel Generators do not fail.	$400K	>$7,000K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 14 in Unit 2. See report section 7.3.	Cost exceeds benefit.
25	Install an independent active or passive high pressure injection system.	Improved prevention of core melt sequences.	0.52%	0.42%	LOCA02	Assumed high pressure injection does not fail; works perfectly.	$23.7K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
26	Provide an additional high pressure injection pump with independent diesel.	Reduced frequency of core melt from small LOCA and SBO sequences.	0.52%	0.42%	LOCA02	Assumed high pressure injection does not fail; works perfectly.	$23.7K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
28	Add a diverse low pressure injection system.	Improved injection capability.	0.00%	0.02%	LOCA03	Assumed low pressure injection system does not fail.	$2.1K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
29	Provide capability for alternate injection via diesel-driven fire pump.	Improved injection capability.	0.00%	0.02%	LOCA03	Assumed low pressure injection system does not fail.	$2.1K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
37	Upgrade the chemical and volume control system to mitigate small LOCAs.	For a plant like the Westinghouse AP600, where the chemical and volume control system cannot mitigate a small LOCA, an upgrade would decrease the frequency of core damage.	1.03%	0.89%	LOCA01	Eliminated all small LOCA events.	$48.0K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
39	Replace two of the four electric safety injection pumps with diesel-powered pumps.	Reduced common cause failure of the safety injection system. This SAMA was originally intended for the Westinghouse-CE System 80+, which has four trains of safety injection. However, the intent of this SAMA is to provide diversity within the high- and low-pressure safety injections systems.	0.52%	0.42%	LOCA02	Assumed high pressure injection does not fail; works perfectly.	$23.7K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
41	Create a reactor coolant depressurization system.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	1.03%	0.89%	LOCA01	Eliminated all small LOCA events.	$48.0K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
48	Cap downstream piping of normally closed component cooling water drain and vent valves.	Reduced frequency of loss of component cooling water initiating events, some of which can be attributed to catastrophic failure of one of the many single isolation valves.	0.00%	0.01%	CCW01	Assumed CCW pumps do not fail.	<$1K	>$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
54	Increase charging pump lube oil capacity.	Increased time before charging pump failure due to lube oil overheating in loss of cooling water sequences.	0.00%	0.00%	CHG01	Remove the dependency of the charging pumps on cooling water.	<$1K	>$300K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
55	Install an independent reactor coolant pump seal injection system, with dedicated diesel.	Reduced frequency of core damage from loss of component cooling water, service water, or station blackout.	28.87%	24.74%	RCPLOCA2	This case is used to determine the benefit of eliminating all RCP seal LOCA events. This allows evaluation of various possible improvements that could reduce the risk associated with RCP seal LOCA and other small LOCA events.	$1,303K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
56	Install an independent reactor coolant pump seal injection system, without dedicated diesel.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	28.87%	24.74%	RCPLOCA2	This case is used to determine the benefit of eliminating all RCP seal LOCA events. This allows evaluation of various possible improvements that could reduce the risk associated with RCP seal LOCA and other small LOCA events.	$1,303K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
64	Implement procedure and hardware modifications to allow manual alignment of the fire water system to the component cooling water system, or install a component cooling water header cross-tie.	Improved ability to cool residual heat removal heat exchangers.	0.00%	0.01%	CCW01	Assumed CCW pumps do not fail.	<$1K	>$15K	Screening Procedure Change Value	Not Cost-Beneficial	Cost exceeds benefit.
65	Install a digital feed water upgrade.	Reduced chance of loss of main feed water following a plant trip.	1.55%	0.61%	FW01	Eliminated all loss of feedwater initiators.	$37.2K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
89	Improve SRV and MSIV pneumatic components.	Improved availability of SRVs and MSIVs.	0.00%	0.00%	INSTAIR1	This case was used to determine the benefit of replacing the air compressors. For the purposes of the analysis, a single bounding analysis was performed which assumed the service and instrument air compressors do not fail.	<$1K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
94	Install a filtered containment vent to remove decay heat. Option 1: Gravel Bed Filter; Option 2: Multiple Venturi Scrubber	Increased decay heat removal capability for non-ATWS events, with scrubbing of released fission products.	0.00%	26.57%	CONT01	Eliminated all failures of containment due to overpressure.	$1,239K	$9,000K	Industry studies (NUREG 1437 supplements), with inflation	Not Cost-Beneficial	Some venting capability currently exists but the post-accident environment could preclude venting. A different vent was considered necessary to assure continued filtering.
96	Provide post-accident containment inerting capability.	Reduced likelihood of hydrogen and carbon monoxide gas combustion.	0.00%	0.49%	H2BURN	Eliminated all Hydrogen detonation.	$30.4K	>$500K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Hydrogen recombiners previously abandoned in place.
98	Create a core melt source reduction system.	Increased cooling and containment of molten core debris. Refractory material would be placed underneath the reactor vessel such that a molten core falling on the material would melt and combine with the material. Subsequent spreading and heat removal from the vitrified compound would be facilitated, and concrete attack would not occur.	0.00%	0.49%	H2BURN	Eliminated all Hydrogen detonation.	$30.4K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Hydrogen recombiners previously abandoned in place.
104	Improve leak detection procedures.	Increased piping surveillance to identify leaks prior to complete failure. Improved leak detection would reduce LOCA frequency.	0.52%	0.16%	LOCA05	Eliminated all piping failure LOCAs.	$10.7K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Have implemented RI-ISI.
107	Install a redundant containment spray system.	Increased containment heat removal ability.	0.00%	26.57%	CONT01	Eliminated all failures of containment due to overpressure.	$1,239K	$10,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
111	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	Reduced ISLOCA frequency.	0.00%	0.17%	LOCA06	Eliminated all ISLOCA events.	$9.9K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
112	Add redundant and diverse limit switches to each containment isolation valve.	Reduced frequency of containment isolation failure and ISLOCAs.	0.00%	0.11%	CONT02	Eliminated all containment isolation failures.	$5.8K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
113	Increase leak testing of valves in ISLOCA paths.	Reduced ISLOCA frequency.	0.00%	0.17%	LOCA06	Eliminated all ISLOCA events.	$9.9K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Increased outage frequency/duration.
118	Improve operator training on ISLOCA coping.	Decreased ISLOCA consequences.	0.00%	0.17%	LOCA06	Eliminated all ISLOCA events.	$9.9K	See Note 1.	See Note 1.	Not Cost-Beneficial	The current operating procedures and training meet industry standards and include place-keeping and check-off. No cost beneficial improvements could be identified to either training or procedures that would result in a significant change the HEP. Not cost beneficial.
119	Institute a maintenance practice to perform a 100% inspection of steam generator tubes during each refueling outage.	Reduced frequency of steam generator tube ruptures.	0.00%	0.46%	NOSGTR	This case was used to determine the benefit of eliminating all SGTR events. This allows evaluation of various possible improvements that could reduce the risk associated with SGTR events. For the purposes of the analysis, a single bounding analysis was performed which assumed that SGTR events do not occur.	$31.5K	>$3,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
122	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture	Enhanced depressurization capabilities during steam generator tube rupture.	0.00%	0.46%	NOSGTR	This case was used to determine the benefit of eliminating all SGTR events. This allows evaluation of various possible improvements that could reduce the risk associated with SGTR events. For the purposes of the analysis, a single bounding analysis was performed which assumed that SGTR events do not occur.	$31.5K	>$100K	Expert Panel -Screening hardware change value.	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
130	Add an independent boron injection system.	Improved availability of boron injection during ATWS.	1.74%	0.09%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$13.3K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
131	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	Improved equipment availability after an ATWS.	1.74%	0.09%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$13.3K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
133	Install an ATWS sized filtered containment vent to remove decay heat.	Increased ability to remove reactor heat from ATWS events.	1.74%	0.09%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$13.3K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
136	Install motor generator set trip breakers in control room.	Reduced frequency of core damage due to an ATWS.	1.74%	0.09%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$13.3K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
137	Provide capability to remove power from the bus powering the control rods.	Decreased time required to insert control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	1.74%	0.09%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$13.3K	>$100K	Expert Panel - 2004 Strategic Action Plan	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
147	Install digital large break LOCA protection system.	Reduced probability of a large break LOCA (a leak before break).	0.52%	0.16%	LOCA05	Eliminated all piping failure LOCAs.	$10.7K	>$100K	Expert Panel - Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit
153	Install secondary side guard pipes up to the main steam isolation valves.	Prevents secondary side depressurization should a steam line break occur upstream of the main steam isolation valves. Also guards against or prevents consequential multiple steam generator tube ruptures following a main steam line break event.	0.00%	0.01%	NOSLB	This case was used to determine the benefit of installing secondary side guard pipes up to the MSIVs. This would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. For the purposes of the analysis, a single bounding analysis was performed which assumed that no steam line break events occur.	<$1K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
155	Reactor Trip breaker failure , Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	1.74%	0.09%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$13.3K	>$100K	Expert Panel - Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	0.00%	0.46%	NOSGTR	This case was used to determine the benefit of eliminating all SGTR events. This allows evaluation of various possible improvements that could reduce the risk associated with SGTR events. For the purposes of the analysis, a single bounding analysis was performed which assumed that SGTR events do not occur.	$31.5K	$50K	Expert Panel	Potentially Cost-Beneficial (because the upper bound sensitivity benefit exceeds the cost)	SAMA is potentially cost beneficial. Loop stop valves are also not designed to close against differential pressure and under accident conditions will not fully seat since hoses must be installed to provide pressure between the seats to fully seat the valve.

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
165	Install an independent RCP Seal Injection system.	Reduce frequency of RCP seal failure.	28.87%	24.74%	RCPLOCA2	This case is used to determine the benefit of eliminating all RCP seal LOCA events. This allows evaluation of various possible improvements that could reduce the risk associated with RCP seal LOCA and other small LOCA events.	$1,303K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
166	Provide additional emergency 125V DC battery capability.	Better coping for long term station blackouts	0.00%	0.26%	DC01	Assumed no failure or depletion of DC power system.	$13.9K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
167	Increase the seismic ruggedness of the emergency 125V DC battery block walls	Reduce failure of batteries due to seismic induced failure of battery room block walls.	15.46%	26.43%	DC02	Evaluated the impact of increasing the seismic ruggedness of the 125VDC battery room block walls.	$1,302K	$300K	Expert Panel	Potentially Cost-Beneficial	Potentially cost beneficial
168	Install fire barriers for HVAC fans in the cable spreading room	Eliminate failure of fire propagating from one fan to another.	1.55%	2.69%	FIRE01	Eliminated all fires impacting the switchgear HVAC fans.	$133K	$80K	Expert Panel	Potentially Cost-Beneficial	Potentially cost beneficial, reference SAMA 143
169	Improve operator performance. Operator starts Aux RW pump given offsite power is available.	One of top 10 operator actions, OPRWA1	0.00%	0.06%	HEP1	Reduced the probability of basic event OPRWA1 by a factor of 3.	$3.2K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
170	Improve operator performance. Operator starts portable fans & open doors in emergency switchgear room	One of top 10 operator actions, OPRWBV3	1.04%	1.89%	HEP2	Reduced the probability of basic event OPRWBV3 by a factor of 3.	$93.4K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
171	Improve operator performance. Operator initiates Safety Injection	One of top 10 operator actions, OPROS6	0.00%	0.06%	HEP3	Reduced the probability of basic event OPROS6 by a factor of 3.	$3.0K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
172	Improve operator performance. Operator initiates bleed and feed cooling given failure of prior actions to restore feedwater systems.	One of top 10 operator actions, OPROB2	2.66%	0.82%	HEP4	Reduced the probability of basic event OPROB2 by a factor of 3.	$56.7K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
173	Improve operator performance. Operator initiates makeup of RWST	One of top 10 operator actions, OPRWM1	0.00%	0.01%	HEP5	Reduced the probability of basic event OPRWM1 by a factor of 3.	<$1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
174	Improve operator performance. Operator trips RCPs during loss of CCR.	One of top 10 operator actions, OPROC1	0.00%	0.19%	HEP6	Reduced the probability of basic event OPROC1 by a factor of 3.	$9.8K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
175	Improve operator performance. Operator initiates depressurization of RCS given a general transient initiating event.	One of top 10 operator actions, OPROD2	0.00%	0.01%	HEP7	Reduced the probability of basic event OPROD2 by a factor of 3.	<$1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
176	Improve operator performance. Operator initiates depressurization of RCS given a SGTR event.	One of top 10 operator actions, OPROD1	0.00%	0.00%	HEP8	Reduced the probability of basic event OPROD1 by a factor of 3.	<$1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
177	Improve operator performance. Operator initiates cooldown and depressurization of RCS given a Small LOCA and failure of HHSI.	One of top 10 operator actions, OPRCD6	0.00%	0.01%	HEP9	Reduced the probability of basic event OPRCD6 by a factor of 3.	<$1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
178	Improve operator performance. Operator aligns hot leg recirculation.	One of top 10 operator actions, OPRLR1	0.00%	0.00%	HEP10	Reduced the probability of basic event OPRLR1 by a factor of 3.	<$1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
180	Reroute River Water pump power cable	IPEEE issue with CV-3 fire.	0.52%	0.56%	SW01	Removed the DC power dependency for the service water/river water pumps.	$30.2K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
182	Reroute CCR pump or HHSI suction MOV cables.	IPEEE fire issue for PA-1 fire.	0.00%	0.00%	FIRE02	This case eliminates the fires in zone PA-1E causing failure of component cooling water and of seal injection.	<$1K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
183	Reroute river water or auxiliary river water pump power and control cables	IPEEE fire issue for CS-1 fire, NE corner.	2.06%	3.31%	FIRE03	This case eliminates the fires in zone CS-1, northeast corner, that cause failure of both river water pumps and both auxiliary river water pumps.	$163K	>$2,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
184	Reroute river water or auxiliary river water pump power and control cables	IPEEE fire issue for NS-1 fire, south wall.	1.03%	0.93%	FIRE04	This case eliminates the fires in zone NS-1 that cause total loss of river water.	$50.0K	>$2,000	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
186	Add guidance to the SAMG to consider post-accident cross-tie of the two unit containments through the gaseous waste system.	Reduce or prevent the release of radionuclides as a result of containment failure.	0.00%	26.57%	CONT01	Eliminated all failures of containment due to overpressure.	$1,239K	>$10,000 K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 190 in Unit 2. See report section 7.3.	Cost exceeds benefit.

Table 7-1 BVPS Unit 1 Phase II SAMA Analysis (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
187	Increase seismic ruggedness of the ERF Substation batteries. This applies to the battery rack only and not the entire structure.	Increased reliability of the ERF diesel following seismic events	14.95%	9.82%	SEISMIC1	This case assumes a seismic ruggedness for the ERF Substation battery that is the same as that for the station batteries.	$525K	$300K	Expert Panel	Potentially Cost-Beneficial. This SAMA affects both units; see SAMA 186 in Unit 2. See report section 7.3.	Potentially Cost-Beneficial
188	Install a cross-tie between the Unit 1 and Unit 2 RWST.	Increased availability of the RWST for injection.	17.01%	13.77%	LOCA04	Assumed RWST does not run out of water.	$729K	>$4,000K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; the Unit 2 affect is too small to be identified as a SAMA. See report section 7.3.	Cost will exceed benefit. BVPS plans to implement this SAMA by using an alternate mitigation strategy that will provide portable pumps that can be used for RWST makeup by the end of 2007.
189	Provide Diesel backed power for the fuel pool purification pumps and valves used for makeup to the RWST.	Increased availability of the RWST during loss of offsite power and station blackout events.	17.01%	13.77%	LOCA04	Assumed RWST does not run out of water.	$729K	$200K	Expert panel	Potentially Cost-Beneficial	Potentially cost beneficial. BVPS plans to implement this SAMA by using an alternate mitigation strategy that will provide portable pumps that can be used for RWST makeup by the end of 2007.

Note 1 – The current plant procedures and training meet current industry standards. The benefit calculation results provided in this table are based upon an arbitrary reduction in HEP of a factor of 3 and are provided solely to demonstrate the sensitivity of the model to change in the HEP. There are no additional specific procedure improvements that could be identified that would affect the result of the HEP calculations to this level of reduction. Therefore, it is expected that the idealistic benefits presented in the table are not achievable with procedure improvements only and would require additional hardware modifications. In all cases the costs of hardware and procedure changes would exceed the idealistic benefits presented in the table. These SAMAs are, therefore, screened as Not Cost Beneficial.

8 SENSITIVITY ANALYSES

The purpose of performing sensitivity analyses is to examine the impact of analysis assumptions on the results of the SAMA evaluation. This section identifies several sensitivities that can be performed during SAMA (Reference 24, NEI 05-01) and discusses the sensitivity as is applies to Beaver Valley Unit 1 and the impact of the sensitivity on the results of the Phase II SAMA analysis at BVPS-1.

Unless it was otherwise noted, it is assumed in these sensitivity analyses that sufficient margin existed in the maximum benefit estimation that the Phase I screening would not have to be repeated in the sensitivity analyses.

8.1 PLANT MODIFICATIONS

There are no plant modifications that are currently pending that would be expected to impact the results of this SAMA evaluation.

8.2 UNCERTAINTY

Since the inputs to PRA cannot be known with complete certainty, there is possibility that the actual plant risk is greater than the mean values used in the evaluation of the SAMA described in the previous sections. To consider this uncertainty, a sensitivity analysis was performed in which an uncertainty factor was applied to the frequencies calculated by the PRA and the subsequent benefits were calculated based upon the mean risk values multiplied by this uncertainty factor. The uncertainty factor applied is the ratio of the 95th percentile value of the CDF from the PRA uncertainty analysis to the mean value of the CDF. For Unit 1 the 95th percentile value of the CDF is 3.96E-5/yr; therefore, uncertainty factor is 2.04. Table 8-1 provides the benefit results from each of the sensitivities for each of the SAMA cases evaluated.

8.3 PEER REVIEW FACTS/OBSERVATIONS

The model used in this SAMA analysis includes the resolution of the Facts-and-Observations (F&Os) identified during the PRA Peer Review. Therefore, no specific sensitivities were performed related to this issue.

8.4 EVACUATION SPEED

Three evacuation sensitivity cases were performed to determine the impact of evacuation assumptions. One sensitivity case reduced the evacuation speed by a factor of four (0.05 m/sec) and the second increased the speed to 2.24 m/s. The third sensitivity case assumed a factor of 1.5 increase in the alarm time, thus delaying the commencement of physical evacuation.

The base evacuation speed was derived in a conservative manner assuming inclement weather and persons without transportation an average evacuation speed of 0.2 m/s was determined. A decrease in the evacuation speed by a factor of four to 0.05 m/s would have the impact of taking over 2 days to evacuate. Runs with an increase to 2.24 m/s (approximately 5 mph) were also performed to assess the slope and relative sensitivity of the dose to evacuation speed.

The third sensitivity case performed was a delay in the alarm time to simulate problems in communication that might be experienced during the night or severe weather. The alarm delay was multiplied by a factor of 1.5 for this case.

The results of the evacuation sensitivity runs indicated that Mean Total Economic Costs are very insensitive to evacuations speeds. Decreasing the evacuation speed had a maximum impact of 10 percent on total dose. Total dose was not sensitive to a delay on the alarm time. The Mean Population Exceeding 0.05 Sv showed some sensitivity to evacuation speed for the late containment failures. The tables below provide a summary of the evacuation sensitivity results.

Table 8.4-1 Evacuation Speed Sensitivity Results

Release Category	Base Note 1	Evacuation Speed				Alarm Delay	
		Slower (0.11 mph	Percent Change	Faster (5 mph)	Percent Change	1.5 x OALARM	Percent Change
Mean L-EFFECTIVE TOT LIF Dose (Sv)							
INTACT	8	8	1	8	-3	8	0
ECF							
VSEQ	50,400	53,700	7	42,700	-15	50,100	-1
SGTR	44,500	47,400	7	40,500	-9	44,700	0
DCH	86,800	88,900	2	81,500	-6	86,800	0
SECF							
SGTR	50,500	55,500	10	29,000	-43	50,500	0
LOCI	35,200	37,200	6	31,700	-10	35,300	0
BV5	43,800	46,400	6	34,600	-21	44,200	1
LATE							
Large	1,530	1,540	1	1,470	-4	1,540	1
Small	20,200	21,400	6	20,200	0	20,300	0
H2 Burn	19,300	19,900	3	18,700	-3	19,400	1
BMMT	7,680	7,850	2	7,670	0	7,680	0
Mean Population Exceeding 0.05 Sv							
INTACT	0	0	0	0	0	0	0
ECF							
VSEQ	143,000	143,000	0	138,000	-3	143,000	0
SGTR	154,000	154,000	0	147,000	-5	154,000	0
DCH	274,000	275,000	0	266,000	-3	274,000	0
SECF							
SGTR	80,200	80,700	1	72,400	-10	80,200	0
LOCI	37,600	38,400	2	28,300	-25	37,400	-1
BV5	86,700	87,200	1	80,100	-8	86,900	0
LATE							
Large	2	27	1,499	2	-8	3	62
Small	7,170	12,900	80	7,150	0	7,240	1
H2 Burn	21,700	24,700	14	18,500	-15	23,000	6
BMMT	2,210	2,730	24	2,200	0	2,240	1
Mean Total Economic Costs ($)							
INTACT	6.400E+03	6.400E+03	0	6.400E+03	0	6.400E+03	0
ECF							
VSEQ	3.530E+10	3.530E+10	0	3.530E+10	0	3.530E+10	0
SGTR	4.280E+10	4.280E+10	0	4.280E+10	0	4.280E+10	0
DCH	4.800E+10	4.800E+10	0	4.800E+10	0	4.800E+10	0
SECF							
SGTR	2.540E+10	2.540E+10	0	2.540E+10	0	2.540E+10	0
LOCI	2.650E+10	2.650E+10	0	2.650E+10	0	2.650E+10	0
BV5	1.130E+10	1.130E+10	0	1.130E+10	0	1.130E+10	0
LATE							
Large	1.180E+08	1.180E+08	0	1.180E+08	0	1.180E+08	0
Small	1.090E+10	1.090E+10	0	1.090E+10	0	1.090E+10	0
H2 Burn	6.670E+09	6.670E+09	0	6.670E+09	0	6.670E+09	0
BMMT	4.380E+09	4.380E+09	0	4.380E+09	0	4.380E+09	0

Note 1 Current Economic data, 2047 population data, and 2001 met data

8.5 REAL DISCOUNT RATE

Calculation of severe accident impacts in the BVPS-1 SAMA analysis was performed using a "real discount rate" of 7% (0.07/year) as recommended in Reference 20, NUREG/BR-0184. Use of both a 7% and 3% real discount rate in regulatory analysis is specified in Office of Management Budget (OMB) guidance (Reference 25) and in NUREG/BR-0058 (Reference 26). Therefore, a sensitivity analysis was performed using a 3% real discount rate.

In this sensitivity analysis, the real discount rate in the Level 3 PRA model was changed to 3% from 7% and the Phase II analysis was re-performed with the lower interest rate.

The results of this sensitivity analysis are presented in Table 8-1. This sensitivity analysis does not challenge any decisions made regarding the SAMAs.

8.6 ANALYSIS PERIOD

As described in Section 4, calculation of severe accident impacts involves an analysis period term, t_f, which could have been defined as either the period of extended operation (20 years), or the years remaining until the end of facility life (from the time of the SAMA analysis to the end of the period of extended operation) (29 years for Unit 1).

The value used for this term was the period of extended operation (20 years). This sensitivity analysis was performed using the period from the time of the SAMA analysis to the end of the period of extended operation to determine if SAMAs would be potentially cost-beneficial if performed immediately.

In this sensitivity analysis, the analysis period in the calculation of severe accident risk was modified to 29 years and the Phase II analysis was re-performed with the revised analysis period. The cost of additional years of maintenance, surveillance, calibrations, and training were included appropriately in the cost estimates for SAMAs in this Phase II analysis.

The results of this sensitivity analysis are presented in Table 8-1. This sensitivity analysis does not challenge any decisions made regarding the SAMAs.

Table 8-1 BVPS Unit 1 Sensitivity Evaluation

BV1 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
1	Provide additional DC battery capacity.	Extended DC power availability during an SBO.	DC01	$13.9K	$20.1K	$12.4K	$16.5K	$26.7K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
2	Replace lead-acid batteries with fuel cells.	Extended DC power availability during an SBO.	DC01	$13.9K	$20.1K	$12.4K	$16.5K	$26.7K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
4	Improve DC bus load shedding.	Extended DC power availability during an SBO.	DC01	$13.9K	$20.1K	$12.4K	$16.5K	$26.7K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
5	Provide DC bus cross-ties.	Improved availability of DC power system.	DC01	$13.9K	$20.1K	$12.4K	$16.5K	$26.7K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
6	Provide additional DC power to the 120/240V vital AC system.	Increased availability of the 120 V vital AC bus.	DC01	$13.9K	$20.1K	$12.4K	$16.5K	$26.7K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
13	Install an additional, buried off-site power source.	Reduced probability of loss of off-site power.	NOLOSP	$73.7K	$105K	$66.0.K	$86.K	$144K	>$2,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
14	Install a gas turbine generator.	Increased availability of on-site AC power.	NOSBO	$400K	$577K	$357K	$473K	$768K	>$7,000K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 14 in Unit 2. See report section 7.3.	Cost exceeds benefit.
25	Install an independent active or passive high pressure injection system.	Improved prevention of core melt sequences.	LOCA02	$23.7K	$34.5K	$21.1K	$28.2K	$45.0K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
26	Provide an additional high pressure injection pump with independent diesel.	Reduced frequency of core melt from small LOCA and SBO sequences.	LOCA02	$23.7K	$34.5K	$21.1K	$28.2K	$45.0K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
28	Add a diverse low pressure injection system.	Improved injection capability.	LOCA03	$2.1K	$3.3K	$1.8K	$2.6K	$3.2K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
29	Provide capability for alternate injection via diesel-driven fire pump.	Improved injection capability.	LOCA03	$2.1K	$3.3K	$1.8K	$2.6K	$3.2K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
37	Upgrade the chemical and volume control system to mitigate small LOCAs.	For a plant like the Westinghouse AP600, where the chemical and volume control system cannot mitigate a small LOCA, an upgrade would decrease the frequency of core damage.	LOCA01	$48.0K	$69.2K	$42.8K	$56.7K	$92.0K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
39	Replace two of the four electric safety injection pumps with diesel-powered pumps.	Reduced common cause failure of the safety injection system. This SAMA was originally intended for the Westinghouse-CE System 80+, which has four trains of safety injection. However, the intent of this SAMA is to provide diversity within the high- and low-pressure safety injections systems.	LOCA02	$23.7K	$34.5K	$21.1K	$28.2K	$45.0K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
41	Create a reactor coolant depressurization system.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	LOCA01	$48.0K	$69.2K	$42.8K	$56.7K	$92.0K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
48	Cap downstream piping of normally closed component cooling water drain and vent valves.	Reduced frequency of loss of component cooling water initiating events, some of which can be attributed to catastrophic failure of one of the many single isolation valves.	CCW01	<$1K	<$1K	<$1K	<$1K	<$1K	>$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
54	Increase charging pump lube oil capacity.	Increased time before charging pump failure due to lube oil overheating in loss of cooling water sequences.	CHG01	<$1K	<$1K	<$1K	<$1K	<$1K	>$300K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
55	Install an independent reactor coolant pump seal injection system, with dedicated diesel.	Reduced frequency of core damage from loss of component cooling water, service water, or station blackout.	RCPLOCA2	$1,303K	$1,867K	$1,165K	$1,532K	$2,535K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.

Table 8-1 BVPS Unit 1 Sensitivity Evaluation (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
56	Install an independent reactor coolant pump seal injection system, without dedicated diesel.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	RCPLOCA2	$1,303K	$1,867K	$1,165K	$1,532K	$2,535K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
64	Implement procedure and hardware modifications to allow manual alignment of the fire water system to the component cooling water system, or install a component cooling water header cross-tie.	Improved ability to cool residual heat removal heat exchangers.	CCW01	<$1K	<$1K	<$1K	<$1K	<$1K	>$15K	Screening Procedure Change Value	Not Cost-Beneficial	Cost exceeds benefit.
65	Install a digital feed water upgrade.	Reduced chance of loss of main feed water following a plant trip.	FW01	$37.2K	$55.1K	$32.9K	$44.9K	$67.8K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
89	Improve SRV and MSIV pneumatic components.	Improved availability of SRVs and MSIVs.	INSTAIR1	<$1K	<$1K	<$1K	<$1K	<$1K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
94	Install a filtered containment vent to remove decay heat. Option 1: Gravel Bed Filter; Option 2: Multiple Venturi Scrubber	Increased decay heat removal capability for non-ATWS events, with scrubbing of released fission products.	CONT01	$1,239K	$1,732K	$1,118K	$1,429K	$2,526K	$9,000K	Industry studies (NUREG 1437 supplements), with inflation	Not Cost-Beneficial	Some venting capability currently exists but the post-accident environment could preclude venting. A different vent was considered necessary to assure continued filtering.
96	Provide post-accident containment inerting capability.	Reduced likelihood of hydrogen and carbon monoxide gas combustion.	H2BURN	$30.4K	$42.3K	$27.4K	$34.9K	$62.3K	>$500K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Hydrogen recombiners previously abandoned in place.
98	Create a core melt source reduction system.	Increased cooling and containment of molten core debris. Refractory material would be placed underneath the reactor vessel such that a molten core falling on the material would melt and combine with the material. Subsequent spreading and heat removal from the vitrified compound would be facilitated, and concrete attack would not occur.	H2BURN	$30.4K	$42.3K	$27.4K	$34.9K	$62.3K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Hydrogen recombiners previously abandoned in place.
104	Improve leak detection procedures.	Increased piping surveillance to identify leaks prior to complete failure. Improved leak detection would reduce LOCA frequency.	LOCA05	$10.7K	$16.2K	$9.4K	$13.2K	$18.6K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Have implemented RI-ISI.
107	Install a redundant containment spray system.	Increased containment heat removal ability.	CONT01	$1,239K	$1,732K	$1,118K	$1,429K	$2,526K	$10,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
111	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	Reduced ISLOCA frequency.	LOCA06	$9.9K	$14.0K	$8.9K	$11.5K	$19.7K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
112	Add redundant and diverse limit switches to each containment isolation valve.	Reduced frequency of containment isolation failure and ISLOCAs.	CONT02	$5.8K	$8.2K	$5.2K	$6.7K	$11.4K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
113	Increase leak testing of valves in ISLOCA paths.	Reduced ISLOCA frequency.	LOCA06	$9.9K	$14.0K	$8.9K	$11.5K	$19.7K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Increased outage frequency/duration.
118	Improve operator training on ISLOCA coping.	Decreased ISLOCA consequences.	LOCA06	$9.9K	$14.0K	$8.9K	$11.5K	$19.7K	See Note 1.	See Note 1.	Not Cost-Beneficial	The current operating procedures and training meet industry standards and include place-keeping and check-off. No cost beneficial improvements could be identified to either training or procedures that would result in a significant change the HEP. Not cost beneficial.

Table 8-1 BVPS Unit 1 Sensitivity Evaluation (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
119	Institute a maintenance practice to perform a 100% inspection of steam generator tubes during each refueling outage.	Reduced frequency of steam generator tube ruptures.	NOSGTR	$31.4K	$44.3K	$28.3K	$36.6K	$62.9K	>$3,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
122	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture	Enhanced depressurization capabilities during steam generator tube rupture.	NOSGTR	$31.4K	$44.3K	$28.3K	$36.6K	$62.9K	>$100K	Expert Panel - Screening hardware change value.	Not Cost-Beneficial	Cost exceeds benefit.
130	Add an independent boron injection system.	Improved availability of boron injection during ATWS.	NOATWS	$13.3K	$21.7K	$11.3K	$17.3K	$18.9K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
131	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	Improved equipment availability after an ATWS.	NOATWS	$13.3K	$21.7K	$11.3K	$17.3K	$18.9K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
133	Install an ATWS sized filtered containment vent to remove decay heat.	Increased ability to remove reactor heat from ATWS events.	NOATWS	$13.3K	$21.7K	$11.3K	$17.3K	$18.9K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
136	Install motor generator set trip breakers in control room.	Reduced frequency of core damage due to an ATWS.	NOATWS	$13.3K	$21.7K	$11.3K	$17.3K	$18.9K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
137	Provide capability to remove power from the bus powering the control rods.	Decreased time required to insert control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	NOATWS	$13.3K	$21.7K	$11.3K	$17.3K	$18.9K	>$100K	Expert Panel - 2004 Strategic Action Plan	Not Cost-Beneficial	Cost exceeds benefit.
147	Install digital large break LOCA protection system.	Reduced probability of a large break LOCA (a leak before break).	LOCA05	$10.7K	$16.2K	$9.4K	$13.2K	$18.6K	>$100K	Expert Panel - Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit
153	Install secondary side guard pipes up to the main steam isolation valves.	Prevents secondary side depressurization should a steam line break occur upstream of the main steam isolation valves. Also guards against or prevents consequential multiple steam generator tube ruptures following a main steam line break event.	NOSLB	<$1K	<$1K	<$1K	<$1K	$1.0K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
155	Reactor Trip breaker failure , Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	NOATWS	$13.3K	$21.7K	$11.3K	$17.3K	$18.9K	>$100K	Expert Panel - Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	NOSGTR	$31.4K	$44.3K	$28.3K	$36.6K	$62.9K	$31.4K	Expert Panel	Potentially Cost-Beneficial (because the upper bound sensitivity benefit exceeds the cost)	SAMA is potentially cost beneficial. Loop stop valves are also not designed to close against differential pressure and under accident conditions will not fully seat since hoses must be installed to provide pressure between the seats to fully seat the valve.
165	Install an independent RCP Seal Injection system.	Reduce frequency of RCP seal failure.	RCPLOCA2	$1,303K	$1,867K	$1,165K	$1,532K	$2,535K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
166	Provide additional emergency 125V DC battery capability.	Better coping for long term station blackouts	DC01	$13.9K	$20.1K	$12.4K	$16.5K	$26.7K	$50K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
167	Increase the seismic ruggedness of the emergency 125V DC battery block walls	Reduce failure of batteries due to seismic induced failure of battery room block walls.	DC02	$1,302K	$1,844K	$1,169K	$1,517K	$2,589K	$300K	Expert Panel	Potentially Cost-Beneficial	Potentially cost beneficial
168	Install fire barriers for HVAC fans in the cable spreading room	Eliminate failure of fire propagating from one fan to another.	FIRE01	$133K	$188K	$119K	$155K	$264K	$80K	Expert Panel	Potentially Cost-Beneficial	Potentially cost beneficial, reference SAMA 143
169	Improve operator performance. Operator starts Aux RW pump given offsite power is available.	One of top 10 operator actions, OPRWA1	HEP1	$3.2K	$4.7K	$2.9K	$3.8K	$6.2K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.

Table 8-1 BVPS Unit 1 Sensitivity Evaluation (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
170	Improve operator performance. Operator starts portable fans & open doors in emergency switchgear room	One of top 10 operator actions, OPRWBV3	HEP2	$93.4K	$132K	$83.8K	$109K	$185K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
171	Improve operator performance. Operator initiates Safety Injection	One of top 10 operator actions, OPROS6	HEP3	$3.0K	$4.3K	$2.7K	$3.5K	$5.9K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
172	Improve operator performance. Operator initiates bleed and feed cooling given failure of prior actions to restore feedwater systems.	One of top 10 operator actions, OPROB2	HEP4	$56.7K	$83.7K	$50.2K	$68.3K	$104K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
173	Improve operator performance. Operator initiates makeup of RWST	One of top 10 operator actions, OPRWM1	HEP5	<$1K	<$1K	<$1K	<$1K	$1.1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
174	Improve operator performance. Operator trips RCPs during loss of CCR.	One of top 10 operator actions, OPROC1	HEP6	$9.8K	$14.1K	$8.8K	$11.6K	$19.0K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
175	Improve operator performance. Operator initiates depressurization of RCS given a general transient initiating event.	One of top 10 operator actions, OPROD2	HEP7	<$1K	<$1K	<$1K	<$1K	<$1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
176	Improve operator performance. Operator initiates depressurization of RCS given a SGTR event.	One of top 10 operator actions, OPROD1	HEP8	<$1K	<$1K	<$1K	<$1K	<$1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
177	Improve operator performance. Operator initiates cooldown and depressurization of RCS given a Small LOCA and failure of HHSI.	One of top 10 operator actions, OPRCD6	HEP9	<$1K	$1.3K	<$1K	<$1K	$1.1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
178	Improve operator performance. Operator aligns hot leg recirculation.	One of top 10 operator actions, OPRLR1	HEP10	<$1K	<$1K	<$1K	<$1K	<$1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1.
180	Reroute River Water pump power cable	IPEEE issue with CV-3 fire.	SW01	$30.2K	$43.5K	$26.9K	$35.7K	$58.0K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
182	Reroute CCR pump or HHSI suction MOV cables.	IPEEE fire issue for PA-1 fire.	FIRE02	<$1K	<$1K	<$1K	<$1K	<$1K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
183	Reroute river water or auxiliary river water pump power and control cables	IPEEE fire issue for CS-1 fire, NE corner.	FIRE03	$163K	$232K	$147K	$191K	$324K	>$2,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
184	Reroute river water or auxiliary river water pump power and control cables	IPEEE fire issue for NS-1 fire, south wall.	FIRE04	$50.0K	$72.2K	$44.7K	$59.2K	$96.1K	>$2,000	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
186	Add guidance to the SAMG to consider post-accident cross-tie of the two unit containments through the gaseous waste system.	Reduce or prevent the release of radionuclides as a result of containment failure.	CONT01	$1,239K	$1,732K	$1,118K	$1,429K	$2,526K	>$10,000 K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 190 in Unit 2. See report section 7.3.	Cost exceeds benefit.
187	Increase seismic ruggedness of the ERF Substation batteries. This applies to the battery rack only and not the entire structure.	Increased reliability of the ERF diesel following seismic events	SEISMIC1	$525K	$758K	$469K	$621K	$1,009K	$300K	Expert Panel	Potentially Cost-Beneficial. This SAMA affects both units; see SAMA 186 in Unit 2. See report section 7.3.	Potentially Cost-Beneficial
188	Install a cross-tie between the Unit 1 and Unit 2 RWST.	Increased availability of the RWST for injection.	LOCA04	$729K	$1,047K	$652K	$858K	$1,416K	>$4,000K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; the Unit 2 affect is too small to be identified as a SAMA. See report section 7.3.	Cost will exceed benefit. BVPS plans to implement this SAMA by using an alternate mitigation strategy that will provide portable pumps that can be used for RWST makeup by the end of 2007.

Table 8-1 BVPS Unit 1 Sensitivity Evaluation (Cont.)

BV1 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
189	Provide Diesel backed power for the fuel pool purification pumps and valves used for makeup to the RWST.	Increased availability of the RWST during loss of offsite power and station blackout events.	LOCA04	$729K	$1,047K	$652K	$858K	$1,416K	$200K	Expert panel	Potentially Cost-Beneficial	Potentially cost beneficial. BVPS plans to implement this SAMA by using an alternate mitigation strategy that will provide portable pumps that can be used for RWST makeup by the end of 2007.

Note 1 – The current plant procedures and training meet current industry standards. The benefit calculation results provided in this table are based upon an arbitrary reduction in HEP of a factor of 3 and are provided solely to demonstrate the sensitivity of the model to change in the HEP. There are no additional specific procedure improvements that could be identified that would affect the result of the HEP calculations to this level of reduction. Therefore, it is expected that the idealistic benefits presented in the table are not achievable with procedure improvements only and would require additional hardware modifications. In all cases the costs of hardware and procedure changes would exceed the idealistic benefits presented in the table. These SAMAs are, therefore, screened as Not Cost Beneficial.

9 CONCLUSIONS

As a result of this analysis, the SAMAs identified in Table 9-1 have been identified as potentially cost beneficial, either directly or as a result of the sensitivity analyses. These SAMA are not aging related and are therefore not required to be resolved as part of the relicensing effort. However, since these potential improvements could result in a reduction in public risk, these SAMAs will be entered into the Beaver Valley long-range plan development process for further consideration.

Implementation of SAMA 164 would involve two actions. The first is a procedural change to direct the operators to close the RCS loop stop valves to isolate a steam generator that has had a tube failure. The second involves purchase or manufacture of a gagging device that could be used to close a stuck open steam generator safety valve (i.e., faulted) on the ruptured steam generator prior to core damage in SGTR events.

Implementation of SAMA 167 would involve installation of restraints on the masonry block walls of the emergency switchgear room. This would reduce failures of those walls following seismic events and prevent damage to the four emergency batteries located in the emergency switchgear rooms.

Implementation of SAMA 168 would involve installation of a fire barrier or fire curtain between the four emergency switchgear fans located in the cable spreading room. This would reduce propagation of a fire from one fan to another.

Implementation of SAMA 187 would involve modifications to increase the seismic ruggedness of the battery racks for the ERF diesel generator to be comparable to the emergency batteries, thereby increasing the ERF diesel generator availability following seismic events.. These ERF Substation batteries are not safety related.

Implementation of SAMA 189 involves purchasing a portable pump that can be used to provide makeup to the RWST. BVPS plans to implement this SAMA through an alternate mitigation strategy by the end of 2007.

None of the SAMAs identified in Table 9-1 are aging-related.

Table 9-1 BVPS Unit 1 Potentially Cost Beneficial SAMAs

BV1 SAMA Number	Potential Improvement	Discussion	Additional Discussion
164	Modify emergency procedures to isolate a faulted SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	
167	Increase the seismic ruggedness of the emergency 125V DC battery block walls	Reduce failure of batteries due to seismic induced failure of battery room block walls.	
168	Install fire barriers for HVAC fans in the cable spreading room	Eliminate failure of fire propagating from one fan to another.	
187	Increase seismic ruggedness of the ERF Substation batteries. This applies to the battery rack only and not the entire structure.	Increased reliability of the ERF diesel following seismic events	
189	Provide Diesel backed power for the fuel pool purification pumps and valves used for makeup to the RWST.	Increased availability of the RWST during loss of offsite power and station blackout events.	BVPS plans to implement this SAMA through alternate mitigation strategies that provide portable pumps that can be used for RWST makeup by the end of 2007.

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APPENDIX A – PRA RUNS FOR SELECTED SAMA CASES

Explanation of Appendix A Contents

This appendix describes each of the SAMA evaluation cases. An evaluation case is an evaluation of plant risk using a plant PRA model that considers implementation of the evaluated SAMA. The case-specific plant configuration is defined as the plant in its baseline configuration with the model modified to represent the plant after the implementation of a particular SAMA. As indicated in the main report, these model changes were performed in a manner expected to bound the change in risk that would actually be expected if the SAMA were implemented. This approach was taken because the actual designs for the SAMAs have not been developed.

Each analysis case is described in the following pages. Each case description contains a description of the physical change that the case represents along with a description of the SAMAs that are being evaluated by this specific case.

The PDS frequencies calculated as a result of the PRA model quantification for each SAMA case is presented in Table A-8.

Case INSTAIR1

Description: This case is used to determine the benefit of replacing the air compressors. For the purposes of the analysis, a single bounding condition was performed, which assumed the station and containment instrument air systems do not fail.

Case NOATWS

Description: This case is used to determine the benefit of eliminating all Anticipated Transient Without Scram (ATWS) events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.

Case NOSGTR

Description: This case is used to determine the benefit of eliminating all Steam Generator Tube Rupture (SGTR) events. This allows evaluation of various possible improvements that could reduce the risk associated with SGTR events. For the purposes of this analysis, a single bounding analysis was performed which assumed that SGTR events do not occur.

Case RCPLOCA

Description: This case is used to determine the benefit of eliminating all Reactor Coolant Pump (RCP) seal loss of coolant accident (LOCA) events. This allows evaluation of various possible improvements that could reduce the risk associated with RCP seal LOCA and other small LOCA events.

Case NOLOSP

Description: This case is used to determine the benefit of eliminating all Loss of Offsite Power (LOSP) events, both as the initiating event and subsequent to a different initiating event. This allows evaluation of various possible improvements that could reduce the risk associated with LOSP events. For the purposes of the analysis, a single bounding analysis was performed which assumed that LOSP events do not occur, both as an initiating event and subsequent to a different initiating event.

Case NOSBO

Description: This case is used to determine the benefit of eliminating all Station Blackout (SBO) events. This allows evaluation of possible improvements related to SBO sequences. For the purpose of the analysis, a single bounding analysis is performed that assumes the emergency AC power supplies do not fail.

Case NOSLB

Description: This case is used to determine the benefit of installing secondary side guard pipes to the Main Steam Isolation Valves (MSIVs). This would prevent secondary side depressurization should a Steam Line Break (SLB) occur upstream of the MSIVs. For the purposes of the analysis, a single bounding analysis was performed which assumed that no SLB inside containment events occur.

HEP Cases

A description of the Operator Actions can be found in the Beaver Valley Unit 1 Probabilistic Risk Assessment Update Report (Reference 27).

All HEP cases are performed using the red button feature of the RISKMAN code; this implies the re-creation of a set of MFFs by the RISKMAN code.

Case HEP1

Description: The probability of basic event OPRWA1, Operator starts Aux RW pump given offsite power is available, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP2

Description: The probability of basic event OPRBV3, Operator starts portable fans & open doors in Emer. Switchgear, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP3

Description: The probability of basic event OPROS6, Operator initiates Safety Injection, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP4

Description: The probability of basic event OPROB2, Operator initiates bleed and feed cooling given failure of prior actions to restore feedwater systems, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP5

Description: The probability of basic event OPRWM1, Operator initiates makeup to RWST, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP6

Description: The probability of basic event OPROC1, Operator trips RCPs during loss of CCR, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP7

Description: The probability of basic event OPROD2, Operator initiates depressurization of RCS given a General Transient initiating event, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP8

Description: The probability of basic event OPROD1, Operator initiates depressurization of RCS given a SGTR initiating event, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP9

Description: The probability of basic event OPRCD6, Operator initiates cooldown and depressurization of RCS given a Small LOCA and failure of HHSI, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP10

Description: The probability of basic event OPRLR1, Operator aligns hot leg recirculation, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case LOCA01

Description: Assume small LOCA events do not occur. This case is used to determine the benefit of eliminating all small LOCA events.

Case LOCA02

Description: Assume the high pressure injection system does not fail. This case is used to determine the benefit of improvements to the High Pressure Injection Systems.

Case LOCA03

Description: Assume failures of the low pressure injection system do not occur. This case is used to determine the benefit of improving the Low Pressure Injection Systems.

Case LOCA04

Description: This case assumes that the RWST cannot be depleted. This case is used to determine the impact of refilling or backup of the water supply for the RWST.

Case LOCA05

Description: Assume that piping system LOCAs do not occur. This case is used to determine the benefit of eliminating all LOCA events related to piping failure (no change to non-piping failure is considered).

Case LOCA06

Description: Assume ISLOCA events do not occur. This case is used to determine the benefit of eliminating all ISLOCA events.

Case DC1

Description: Assume the DC power systems do not fail or deplete. This case is used to determine the impact of the improvement in the DC power system.

Case CHG01

Description: Assume the charging pumps are not dependent on cooling water. This case is used to determine the benefit of removing the charging pumps dependency on cooling water.

Case SW01

Description: Assume the service water pumps are not dependent on DC power. This case is used to determine the benefit of enhancing the DC control power to the service water pumps.

Case CCW01

Description: This case is used to determine the benefit of improvement to the CCW system by assuming that CCW pumps do not fail.

Case FW01

Description: Eliminate loss of feedwater initiating events. This case is used to determine the benefit of improvements to the feedwater and feedwater control systems.

Case RCPLOCA2

Description: This case is used to determine the benefit of eliminating all RCP seal LOCA events except those associated with seismic events with a PGA greater than 0.35g. This allows evaluation of various possible improvements that could reduce the risk associated with RCP seal LOCA and other small LOCA events. RCPLOCA2 (identified as RCPLOCA in the attached *Phase3SAMAMethod.doc* file) is actually an extension of the RCPLOCA case run during Phase I.

Case CONT01

Description: Assume that the containment does not fail due to overpressurization. This case is used to determine the benefit of eliminating all containment failures due to overpressurization.

Case H2BURN

Description: Assume hydrogen burns and detonations do not occur. This case is used to determine the benefit of eliminating all hydrogen ignition and burns.

Case CONT02

Description: Assume there are no failures of containment isolation. This case is used to determine the benefit of eliminating all containment isolation failures.

Case FIRE01

Description: Eliminate the cable spreading room fire that fails switchgear ventilation fans. This case is used to determine the benefit of eliminating all fires that impact the fans in the cable spreading room.

Case DC2

Description: Assume a seismic event does not cause the block wall to fail which in turn fails the batteries. This case is used to determine the benefit of eliminating the seismic failure of the 125VDC battery room block walls.

Case FIRE02

Description: This case eliminates the fires in zone PA-1E causing failure of component cooling water and of seal injection. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case FIRE03

Description: This case eliminates the fires in zone CS-1, northeast corner, that cause failure of both river water pumps and both auxiliary river water pumps. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case FIRE04

Description: This case eliminates the fires in zone NS-1 that cause total loss of river water. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case SEISMIC1

Description: This case reduces the failure of the ERF Substation batteries due to seismic events (by setting the ERF Substation battery seismic capacity equivalent to the Unit 2 125V DC Emergency battery capacity). This case is used to evaluate improvements that would strengthen the ERF Substation battery racks.

Cases SGTR2, SGTR3, and SGTR4

Description: The SG sensitivity cases were performed assuming that the operator action to close the RCS loop stop valves or to gag closed the stuck-open SG SV would only have a 50% probability of success, as opposed to the 100% success probability assumed in the NOSGTR maximum benefit case. To perform the SG sensitivity cases, the sum of SGTR release bin frequencies were divided by the single SGTR initiating event frequency (1.6059E-03) to obtain the SGTR conditional core damage probabilities for each release bin. The following describes how these SGTR release bin frequency sums and conditional release bin frequencies were applied to each sensitivity case.

For the SGTR2 case, where the operators gag a stuck-open SV, only the unscrubbed containment bypass release bin frequency (BV18) would be impacted. Since the assumed operator action to gag closed the stuck-open SG SV has a 50% probability of success, the SGTR BV18 release bin frequency was multiplied by 0.5. However, since the total CDF from SGTRs would not change from performing this action, the other 50% of the BV18 release bin frequency was added to the scrubbed small release bin frequency (BV20). The remaining SGTR release bin frequency sums remained unchanged. These new SGTR bin frequencies were then added to the NOSGTR release bin frequencies to obtain the SGTR2 sensitivity case release bin frequencies.

For the SGTR3 case, where the operators close the RCS loop stop valves, all of the SGTR release bin frequencies are impacted, since this action would essentially terminate the SGTR. Since the assumed operator action to perform this action has a 50% probability of success, the SGTR initiating event frequency was multiplied by 0.5. This new initiating event frequency (8.0295E-04) was then multiplied by each of the SGTR conditional release bin probabilities. The resultant new SGTR bin frequencies were then added to the NOSGTR release bin frequencies to obtain the SGTR3 sensitivity case release bin frequencies.

For the SGTR4 case, where the operators close the RCS loop stop valves and gag a stuck-open SV, all of the SGTR release bin frequencies are impacted, since this action would essentially terminate the SGTR. Since the assumed operator action to perform this action has a 50% probability of success, the SGTR initiating event frequency was multiplied by 0.5. This new initiating event frequency (8.0295E-04) was then multiplied by each of the SGTR conditional release bin probabilities to obtain revised SGTR bin frequencies. Additionally, the unscrubbed containment bypass release bin frequency (BV18) would be reduced by a 50% probability of success for terminating the unscrubbed containment bypass release. Therefore, the revised SGTR BV18 release bin frequency was further reduced by multiplying it by 0.5, and the other 50% of the revised BV18 release bin frequency was added to the revised scrubbed small release bin frequency (BV20). These new SGTR bin frequencies were then added to the NOSGTR release bin frequencies to obtain the SGTR4 sensitivity case release bin frequencies.

Table A-8
BVPS Unit 1 Release Category Frequency Results Obtained From SAMA Cases

BV1 RELEASE CATEGORIES	BASE	INSTAIR1	NOATWS	NOSGTR	RCPLOCA	NOLOSP	NOSBO	NOSLB	HEP1	HEP2	HEP3
Intact	1.00E-06	1.00E-06	6.51E-07	1.00E-06	9.66E-07	9.91E-07	9.82E-07	1.00E-06	1.00E-06	1.00E-06	1.00E-06
ECF-VSEQ	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	3.89E-09	2.04E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08
ECF-SGTR	5.26E-08	5.25E-08	4.52E-08	0.00E+00	5.26E-08	1.38E-08	5.29E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08
ECF-DCH	1.56E-09	1.57E-09	1.56E-09	1.56E-09	7.60E-10	1.53E-09	1.16E-09	1.56E-09	1.56E-09	1.56E-09	1.56E-09
SECF-VSEQ	7.93E-06	7.93E-06	7.93E-06	7.92E-06	8.12E-09	7.91E-06	7.91E-06	7.93E-06	7.93E-06	7.70E-06	7.93E-06
SECF-LOCI	1.27E-07	1.27E-07	1.27E-07	1.27E-07	4.21E-06	1.26E-07	1.23E-07	1.27E-07	1.27E-07	1.27E-07	1.22E-07
SECF-BV5	6.56E-09	6.56E-09	6.56E-09	6.56E-09	3.34E-06	6.50E-09	6.19E-09	6.56E-09	6.56E-09	6.56E-09	3.77E-09
LATE-LARGE	1.33E-08	1.33E-08	8.69E-09	1.33E-08	1.33E-08	1.33E-08	1.32E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08
LATE-SMALL	9.74E-06	9.75E-06	9.74E-06	9.74E-06	2.41E-06	9.54E-06	7.58E-06	9.74E-06	9.73E-06	9.74E-06	9.74E-06
LATE-H2BURN	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	0.00E+00	0.00E+00
LATE-BMMT	5.51E-07	5.51E-07	5.32E-07	5.51E-07	5.39E-07	5.46E-07	5.36E-07	5.50E-07	5.51E-07	5.51E-07	5.50E-07
CDF	1.94E-05	1.94E-05	1.91E-05	1.94E-05	1.16E-05	1.92E-05	1.72E-05	1.94E-05	1.94E-05	1.92E-05	1.94E-05

Table A-1
BVPS Unit 1 Release Category Frequency Results Obtained From SAMA Cases (Cont.)

BV1 RELEASE CATEGORIES	HEP4	HEP5	HEP6	HEP7	HEP8	HEP9	HEP10	LOCA01	LOCA02	LOCA03
Intact	8.33E-07	1.00E-06	1.00E-06	1.00E-06	1.00E-06	9.84E-07	1.00E-06	1.00E-06	9.81E-07	9.73E-07
ECF-VSEQ	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.01E-08	2.05E-08
ECF-SGTR	5.26E-08	5.16E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.18E-08	5.27E-08
ECF-DCH	1.49E-09	1.56E-09	1.56E-09	1.56E-09	1.56E-09	1.56E-09	1.56E-09	1.60E-09	1.54E-09	1.56E-09
SECF-VSEQ	7.93E-06	7.93E-06	7.92E-06	7.93E-06	7.93E-06	7.93E-06	7.93E-06	7.93E-06	7.93E-06	7.93E-06
SECF-LOCI	5.49E-08	1.27E-07	1.27E-07	1.27E-07	1.27E-07	1.27E-07	1.27E-07	1.27E-07	1.25E-07	1.27E-07
SECF-BV5	6.14E-09	6.56E-09	6.56E-09	6.56E-09	6.56E-09	6.56E-09	6.56E-09	6.52E-09	6.56E-09	6.57E-09
LATE-LARGE	1.09E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08	1.30E-08	1.30E-08
LATE-SMALL	9.74E-06	9.74E-06	9.70E-06	9.74E-06	9.74E-06	9.74E-06	9.74E-06	9.48E-06	9.64E-06	9.74E-06
LATE-H2BURN	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	0.00E+00
LATE-BMMT	2.52E-07	5.51E-07	5.50E-07	5.50E-07	5.50E-07	5.46E-07	5.50E-07	5.45E-07	5.24E-07	5.30E-07
CDF	1.89E-05	1.94E-05	1.94E-05	1.94E-05	1.94E-05	1.94E-05	1.94E-05	1.92E-05	1.93E-05	1.94E-05

Table A-1
BVPS Unit 1 Release Category Frequency Results Obtained From SAMA Cases (Cont.)

BV1 RELEASE CATEGORIES	LOCA04	LOCA05	LOCA06	DC1	CHG01	SW01	CCW01	FW01	RCPLOCA2	CONTO1
Intact	1.02E-06	9.11E-07	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	8.13E-07	9.66E-07	5.51E-06
ECF-VSEQ	2.81E-09	2.05E-08	0.00E+00	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08
ECF-SGTR	3.09E-09	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08
ECF-DCH	1.56E-09	1.56E-09	1.56E-09	1.55E-09	1.56E-09	1.52E-09	1.56E-09	1.55E-09	1.08E-09	8.87E-11
SECF-VSEQ	7.47E-06	7.93E-06	7.93E-06	7.93E-06	7.93E-06	7.93E-06	7.93E-06	7.93E-06	5.45E-06	7.93E-06
SECF-LOCI	1.26E-07	1.26E-07	1.27E-07	1.27E-07	1.27E-07	1.27E-07	1.27E-07	1.23E-07	1.30E-06	1.14E-08
SECF-BV5	6.55E-09	6.56E-09	6.56E-09	6.56E-09	6.56E-09	6.56E-09	6.56E-09	5.88E-09	8.23E-07	6.37E-09
LATE-LARGE	1.34E-08	1.20E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08	1.08E-08	1.33E-08	0.00E+00
LATE-SMALL	6.94E-06	9.71E-06	9.74E-06	9.67E-06	9.74E-06	9.58E-06	9.74E-06	9.58E-06	4.59E-06	0.00E+00
LATE-H2BURN	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	0.00E+00
LATE-BMMT	5.35E-07	5.26E-07	5.51E-07	5.51E-07	5.50E-07	5.51E-07	5.50E-07	5.30E-07	5.39E-07	5.92E-06
CDF	1.61E-05	1.93E-05	1.94E-05	1.94E-05	1.94E-05	1.93E-05	1.94E-05	1.91E-05	1.38E-05	1.94E-05

Table A-1
BVPS Unit 1 Release Category Frequency Results Obtained From SAMA Cases (Cont.)

BV1 RELEASE CATEGORIES	H2BURN	CONT02	FIRE01	DC2	FIRE02	FIRE03	FIRE04	SEISMIC1
Intact	1.01E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06	1.00E-06
ECF-VSEQ	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08	2.05E-08
ECF-SGTR	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08	5.26E-08
ECF-DCH	1.55E-09	1.55E-09	1.56E-09	1.74E-09	1.56E-09	1.56E-09	1.56E-09	9.47E-10
SECF-VSEQ	7.93E-06	7.93E-06	7.60E-06	4.60E-06	7.93E-06	7.53E-06	7.93E-06	7.91E-06
SECF-LOCI	1.25E-08	1.16E-07	1.27E-07	1.26E-07	1.27E-07	1.27E-07	1.27E-07	1.26E-07
SECF-BV5	6.62E-09	1.90E-10	6.56E-09	5.99E-09	6.56E-09	6.56E-09	6.56E-09	5.90E-09
LATE-LARGE	0.00E+00	1.33E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08	1.33E-08
LATE-SMALL	9.75E-06	9.74E-06	9.74E-06	1.00E-05	9.74E-06	9.74E-06	9.47E-06	6.87E-06
LATE-H2BURN	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
LATE-BMMT	6.74E-07	5.51E-07	5.51E-07	5.51E-07	5.50E-07	5.51E-07	5.51E-07	5.50E-07
CDF	1.94E-05	1.94E-05	1.91E-05	1.64E-05	1.94E-05	1.90E-05	1.92E-05	1.65E-05

ATTACHMENT C-2 BEAVER VALLEY UNIT 2 SAMA ANALYSIS

EXECUTIVE SUMMARY

This report provides an analysis of the Severe Accident Mitigation Alternatives (SAMAs) that were identified for consideration by the Beaver Valley Power Station Unit 2. This analysis was conducted on a cost/benefit basis. The benefit results are contained in Section 4 of this report. Candidate SAMAs that do not have benefit evaluations have been eliminated from further consideration for any of the following reasons:

- The cost is considered excessive compared with benefits.
- The improvement is not applicable to Beaver Valley Unit 2.
- The improvement has already been implemented at Beaver Valley Unit 2 or the intent of the improvement is met for Beaver Valley Unit 2.

After eliminating a portion of the SAMAs for the preceding reasons, the remaining SAMAs are evaluated from a cost-benefit perspective. In general, the analysis approach examines the SAMAs from a bounding analysis approach to determine whether the expected cost would exceed a conservative approximation of the actual expected benefit. In most cases, therefore, a detailed risk evaluation in which a specific modification/procedure change is evaluated would indicate a smaller benefit than calculated in this evaluation.

Major insights from this benefit evaluation process included the following:

If all core damage risk is eliminated, then the benefit in dollars over 20 years is $5,093,366.

- The largest contributors to the total benefit estimate are from offsite dose and offsite property damage.
- A large number of SAMAs had already been addressed by existing plant features, modifications to improve the plant, existing procedures, or procedure changes to enhance human performance.

The following SAMAs have been identified as potentially cost-beneficial.

BV2 SAMA Number	Potential Improvement	Discussion	Additional Discussion
3	Add additional battery charger or portable, diesel-driven battery charger to existing DC system.	Improved availability of DC power system.	
78	Modify the startup feedwater pump so that it can be used as a backup to the emergency feedwater system, including during a station blackout scenario.	Increased reliability of decay heat removal.	This would provide a system similar to the dedicated AFW pump present at Unit 1.
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	

1 INTRODUCTION

1.1 PURPOSE

The purpose of the analysis is to identify SAMA candidates at the Beaver Valley Power Station Unit 2 that have the potential to reduce severe accident risk and to determine whether implementation of the individual SAMA candidate would be cost beneficial. NRC license renewal environmental regulations require SAMA evaluation.

1.2 REQUIREMENTS

- 10 CFR 51.53(c)(3)(ii)(L)
    - The environmental report must contain a consideration of alternatives to mitigate severe accidents "…if the staff has not previously considered severe accident mitigation alternatives for the applicant's plant in an environmental impact statement or related supplement or in an environment assessment..."
- 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 76
    - "…The probability weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to ground water, and societal and economic impacts from severe accidents are small for all plants. However, alternatives to mitigate severe accidents must be considered for all plants that have not considered such alternatives…."

2 METHOD

The SAMA analysis approach applied in the Beaver Valley assessment consists of the following steps.

- **Determine Severe Accident Risk**

    Level 1 and 2 Probabilistic Risk Assessment (PRA) Model
    The Beaver Valley Unit 2 PRA model (Section 3.1 – 3.2) was used as input to the consolidated Beaver Valley Unit 1/2 Level 3 PRA analysis (Section 3.4).

    The PRA results include the risk from internal and external events. The external hazards evaluated in the PRA are internal fires and seismic events only. High winds and tornadoes, external floods, and transportation and nearby facility accidents are not included in the results since they were screened from the IPEEE submittal because their individual CDF fell below the cutoff criteria of 1.0E-06 per year.

Level 3 PRA Analysis
The Level 1 and 2 PRA output and site-specific meteorology, demographic, land use, and emergency response data was used as input for the consolidated Beaver Valley Unit 1/2 Level 3 PRA (Section 3)**.** This combined model was used to estimate the severe accident risk i.e., off-site dose and economic impacts of a severe accident.

- **Determine Cost of Severe Accident Risk / Maximum Benefit**

The NRC regulatory analysis techniques to estimate the cost of severe accident risk were used throughout this analysis. In this step these techniques were used to estimate the maximum benefit that a SAMA could achieve if it eliminated all risk i.e., the maximum benefit (Section 4).

- **SAMA Identification**

In this step potential SAMA candidates (plant enhancements that reduce the likelihood of core damage and/or reduce releases from containment) were identified by Beaver Valley Unit 2 (BVPS-2) plant staff, from the PRA model, Individual Plant Examination (IPE) and IPE – External Events (IPEEE) recommendations, and industry documentation (Section 5). This process included consideration of the PRA importance analysis because it has been demonstrated by past SAMA analyses that SAMA candidates are not likely to prove cost-beneficial if they only mitigate the consequences of events that present a low risk to the plant.

- **Preliminary Screening (Phase I SAMA Analysis)**

Because many of the SAMA candidates identified in the previous step are from the industry, it was necessary to screen out SAMA candidates that were not applicable to the BVPS-2 design, candidates that had already been implemented or whose benefits have been achieved at the plant using other means, and candidates whose roughly estimated cost exceeded the maximum benefit. Additionally, PRA insights (specifically, importance measures) were used directly to screen SAMA candidates that did not address significant contributors to risk in this phase (Section 6).

- **Final Screening (Phase II SAMA Analysis)**

In this step of the analysis the benefit of severe accident risk reduction was estimated for each of the remaining SAMA candidates and compared to an implementation cost estimate to determine net cost-benefit (Section 7). The benefit associated with each SAMA was determined by the reduction in severe accident risk from the baseline derived by modifying the plant model to represent the plant after implementing the candidate. In general, the modeling approach used was a bounding approach to first determine a bounding value of the benefit. If this benefit was determined to be smaller that the expected cost, no further modeling detail was necessary. If the benefit was found to be greater that the estimated cost, the modeling was refined to remove conservatism in the modeling and a less conservative benefit was determined for comparison with the estimated cost.

Similarly, the initial cost estimate used in this analysis was the input from the expert panel (plant staff familiar with design, construction, operation, training and maintenance) meeting. All costs associated with a SAMA were considered, including design, engineering, safety analysis, installation, and long-term maintenance, calibrations, training, etc. If the estimated cost was found to be close to the estimated benefit, then first the benefit evaluation was refined to remove conservatism and if the estimated cost and benefit were still close, then the cost estimate was refined to assure that both the benefit calculation and the cost estimate are sufficiently accurate to justify further decision making based upon the estimates.

- **Sensitivity Analysis**

The next step in the SAMA analysis process involved evaluation on the impact of changes in SAMA analysis assumptions and uncertainties on the cost-benefit analysis (Section 8).

- **Identify Conclusions**

The final step involved summarizing the results and conclusions (Section 9).

3 SEVERE ACCIDENT RISK

The BVPS PRA models describe the results of the first two levels of the BVPS probabilistic risk assessment for the plant’s two units. These levels are defined as follows: Level 1 determines CDFs based on system analyses and human reliability assessments; Level 2 evaluates the impact of severe accident phenomena on radiological releases and quantifies the condition of the containment and the characteristics of the release of fission products to the environment. The BVPS models use PRA techniques to:

- Develop an understanding of severe accident behavior;
- Understand the most likely severe accident consequences;

- Gain a quantitative understanding of the overall probabilities of core damage and fission product releases; and
- Evaluate hardware and procedure changes to assess the overall probabilities of core damage and fission product releases.

The Unit 1 and Unit 2 PRAs were initiated in response to Generic Letter 88-20, which resulted in IPE and IPE for External Events (IPEEE) analyses. The current model for each Unit (BV1REV4 for Unit 1 and BV2REV4 for Unit 2) is a consolidated Level 1 / Level 2 model including both internal and external initiating events (i.e., consolidates IPE and IPEEE studies into a single, Unit-specific PRA model) for power operation. This means that severe accident sequences have been developed from internal and external initiated events, including internal floods, internal fires, and seismic events.

The PRA models used in this analysis to calculate severe accident risk due to Unit 2 are described in this section. The Unit 2 Level 1 PRA model (internal and external), the Unit 2 Level 2 PRA model, Unit 2 PRA model review history, and the consolidated Unit 1/2 Level 3 PRA model, are described in Section 3.1, 3.2 and 3.4. Include results of the severe accident risk calculation as shown in Section 3.5.

3.1 LEVEL 1 PRA MODEL

3.1.1 Internal Events

3.1.1.1 Description of Level 1 Internal Events PRA Model

The US Nuclear Regulatory Commission (NRC) issued Generic Letter No. 88-20, in December 1988, which requested each plant to perform an individual plant examination of internal events (IPE) to identify any vulnerabilities. In response, Duquesne Light Company (DLC) submitted an IPE report (Reference 4) using a probabilistic risk assessment (PRA) approach for Beaver Valley Power Station Unit 2 (BVPS-2) in March 1992 that examined risk from internal events, including internal flooding.

The updated PRA model, used to determine CDF, is the BV2REV4 model. This model contains the Level 1 model for internal initiating events. The software used in the update process was RISKMAN. A Level 1 PRA presents the risk (that is, what can go wrong and what is the likelihood?) associated with core damage. For the updated PRA, core damage is defined as the uncovery and heatup of the reactor core to the point where prolonged cladding oxidation and severe fuel damage is anticipated. This condition is expected whenever the core exit temperatures exceed 1,200°F and the core peak nodal temperatures exceed 1,800°F.

The Beaver Valley Unit 2 Internal Events CDF is calculated to be 9.53E-06 /year. The fault tree method of quantification is binary decision diagram quantification, which provides an exact solution for split fraction values. The event tree quantification was calculated using a truncation cutoff frequency of 1.0E-14, or more than 8 orders of magnitude below the baseline CDF. The results of the CDF quantification of risk from internal events is summarized in Table 3.1.1.1-1 (Initiating Event Contribution to core damage) Table 3.1.1.1-2 (Basic Event Importance) and Table 3.1.1.1-3 (Component Importance). Contribution to internal events CDF from ATWS and SBO sequences is presented below for information purposes.

	Contribution to CDF (/year)
ATWS	1.57E-07
SBO	8.14E-07

The original PRA model (IPE submittal) was based on the BVPS-2 plant configuration circa 1988 and was calculated using a plant specific database that included equipment failures and maintenance history from startup until the end of 1988. During the IPEEE submittal (Reference 5), the PRA had a “freeze date” of December 31, 1996 for both plant configuration and component failure data. The results presented in this report are based on an updated PRA model (BV2REV4), which has a “freeze date” of November 13, 2006 for the plant configuration, and a “freeze date” of December 31, 2005 for component failure data and internal initiating events data. Equipment unavailabilities were based on Maintenance Rule availability history from June 1, 2000 to December 31, 2005. This updated PRA model was also revised to include modeling enhancements.

Table 3.1.1.1-1: BV2REV4 Dominant Initiating Event Contribution to Internal Core Damage					
Initiator	**Description**	**Initiating Event Frequency**	**Contribution to Internal CDF**	**Percent of Internal CDF**	**Cumulative Percent of Internal CDF**
BPX	Loss of Emergency 4160V AC Purple	1.40E-02	2.02E-06	21.2%	21.2%
AOX	Loss of Emergency 4160V AC Orange	1.43E-02	1.78E-06	18.7%	39.9%
LOSPE	Loss of Offsite Power - Extreme Weather Related	2.24E-03	6.61E-07	6.9%	46.8%
CVFLF	Cable Vault Flood from Fire Water	1.46E-04	6.07E-07	6.4%	53.2%
WCX	Loss of Service Water Trains A & B	2.61E-06	5.29E-07	5.5%	58.7%
SGFL2	Both Safeguards Area Flood, Nonisolated	4.88E-05	3.52E-07	3.7%	62.4%
ICX	Loss of Containment Instrument Air	8.59E-02	2.94E-07	3.1%	65.5%
VSX	V-Sequence Initiating Event	2.80E-07	2.80E-07	2.9%	68.5%
ELOCA	Excessive Loss of Coolant Accident	2.66E-07	2.66E-07	2.8%	71.2%
DPX	Loss of Emergency 125V DC Purple	1.03E-02	2.64E-07	2.8%	74.0%
DOX	Loss of Emergency 125V DC Orange	1.03E-02	2.53E-07	2.7%	76.7%
TTRIP	Turbine/Generator Trip	4.49E-01	2.20E-07	2.3%	79.0%
WBXX	Loss of Service Water Train B	4.72E-03	1.53E-07	1.6%	80.6%
RTRIP	Reactor Trip	2.96E-01	1.34E-07	1.4%	82.0%
WAX	Loss of Service Water Train A	4.15E-03	1.30E-07	1.3%	83.4%
SGTRC	Loop C Steam Generator Tube Rupture	1.61E-03	1.23E-07	1.3%	84.7%
SGTRA	Loop A Steam Generator Tube Rupture	1.61E-03	1.23E-07	1.3%	85.9%
SGTRB	Loop B Steam Generator Tube Rupture	1.61E-03	1.23E-07	1.3%	87.2%
PLMFW	Partial Loss of Main Feedwater	2.44E-01	1.11E-07	1.2%	88.4%
SGFL1A	S. Safeguards Train A Area Flood, Isolated	3.65E-04	1.11E-07	1.2%	89.6%
LOSPG	Loss of Offsite Power - Grid Related	1.33E-02	8.01E-08	0.8%	90.4%

Table 3.1.1.1-2 BV2REV4 Top 10 Basic Events by Risk Reduction Worth (Internal Events)				
Rank	**Basic Event Name**	**Basic Event Description**	**RRW***	**Applicable SAMA**
1	BSOR480VUS29	Bus 480VUS-2-9 Fails During Operation	1.12E+00	AC Power SAMAs
2	BSOR4KVS2DF	4160V Bus 4KVS-2DF Fails During Operation	1.12E+00	AC Power SAMAs
3	BSOR480VUS28	Bus 480VUS-2-8 Fails During Operation	1.10E+00	AC Power SAMAs
4	BSOR4KVS2AE	4160V Bus 4KVS-2AE Fails During Operation	1.10E+00	AC Power SAMAs
5	PTSR2FWEP22	Turbine Drive Pump 2FWE-P22 Fails to Run	1.10E+00	SAMA 78
6	CBFC4KVS2D2D7	SSST-2B Incoming BKR ACB-342B (4KVS-2D-2D7) Fails to Close	1.06E+00	AC Power SAMAs
7	CBFC4KVS2A2A4	SSST-2A Incoming BKR ACB-42A (4KVS-2A-2A4) Fails to Close	1.06E+00	AC Power SAMAs
8	XRORTRF29P	480VUS Transformer TRF-2-9P Fails During Operation	1.05E+00	AC Power SAMAs
9	OGXXXX	Offsite Grid Fails Following Non-LOSP Initiator	1.05E+00	AC Power SAMAs
10	[FNOR2HVWFN257A FNOR2HVWFN257B FNOR2HVWFN257C]	Common Cause Failure of Cubicle Ventilation Fans Fail to Run	1.05E+00	HVAC SAMAs
* The Risk Reduction Worth (RRW) is defined by the following Fussell-Vesley (FV) relationship: RRW = 1 / (1 - FV)				

Table 3.1.1.1-3 BV2REV4 Top 10 Components by Risk Reduction Worth w/o Common Cause (Internal Events)

Rank	Component Name	Component Description	RRW*	Applicable SAMA
1	480VUS-2-9	Emergency 480V AC Bus 480VUS-2-9	1.12E+00	AC Power SAMAs
2	4KVS-2DF	4160V AC Emergency Bus 2DF	1.12E+00	AC Power SAMAs
3	2FWE-P22	Turbine Driven Auxiliary Feedwater Pump	1.11E+00	SAMA 79
4	480VUS-2-8	Emergency 480V AC Bus 480VUS-2-8	1.11E+00	AC Power SAMAs
5	4KVS-2AE	4160V AC Emergency Bus 2AE	1.11E+00	AC Power SAMAs
6	2EGS-EG2-1	Emergency Diesel Generator 2-1	1.08E+00	AC Power SAMAs
7	2EGS-EG2-2	Emergency Diesel Generator 2-2	1.08E+00	AC Power SAMAs
8	TRF-2-9P	Transformer For Substation 2-9	1.07E+00	AC Power SAMAs
9	4KVS-2D-2D7	Incoming Supply Feed Bkr from TR-2B for Bus 2D (ACB-342B)	1.07E+00	AC Power SAMAs
10	TRF-2-8N	Transformer for Substation 2-8	1.06E+00	AC Power SAMAs

* The Risk Reduction Worth (RRW) is defined by the following Fussell-Vesley (FV) relationship:
RRW = 1 / (1 - FV)

3.1.1.2 Level 1 PRA Model Changes since IPE Submittal

The major Level 1 changes incorporated into each revision of the Beaver Valley Unit 2 PRA model are discussed below. The individual effect on CDF by incorporating each of these changes has not been analyzed. However, each change is listed in order of expected importance, with the top change being the most important.

BVPS-2 PRA Model History							
PRA Model	**Rev.**	**Date**	**Internal**		**Total**		**Comments**
			CDF	**LERF**	**CDF**	**LERF**	
BV2	0	03/17/92	1.90E-04	8.44E-06	-	-	IPE Model
BV2REV1	1	09/30/97	5.96E-05	9.05E-07	7.54E-05	1.14E-06	IPEEE model
BV2REV2	2	10/31/97	5.96E-05	9.05E-07	7.54E-05	1.14E-06	Integrated Level 1 and Level 2 models
BV2REV3A	3A	01/31/02	8.50E-06	5.10E-07	1.60E-05	5.10E-07	NEI 00-02 Peer Reviewed
BV2REV3B	3B	05/31/03	2.00E-05	1.14E-06	3.43E-05	1.14E-06	NEI 00-02 Peer Review A/B F&Os addressed
BV2REV4	4	04/02/07	9.53E-06	4.06E-07	2.40E-05	4.09E-07	ACC/EPU Model

<u>Beaver Valley Unit 2 Revision 0</u>

This revision represents the base case IPE quantification and resulted in a core damage frequency of <u>1.90E-04 / year</u> for internal events.

<u>Beaver Valley Unit 2 Revision 1</u>

Beaver Valley Unit 2 Revision 1 served as the baseline risk model for the IPEEE and included implementation of IPE vulnerability enhancements. This model was made with the following model modifications. The changes resulted in an internal events core damage frequency of <u>5.96E-05 / year</u>.

- The updated model gave credit for the operators to depressurize the RCS during small break LOCAs, so that a low head safety injection pump can provide makeup and core cooling, given the failure of the high head safety injection system. The CDF definition was also changed so that both core exit temperatures exceeded 1,200°F and the core peak nodal temperatures exceeded 1,800°F must be present.
- The revised frequency included consideration of the station cross-tie connecting the 4KV normal buses of Beaver Valley Units 1 and 2. The cross-tie model permits credit for the Unit 1 emergency diesel generators, if available, to power either Unit 2

emergency AC bus 2AE or 2DF, given the failure of both Unit 2 emergency diesel generators and a loss of offsite power.

- An analysis was performed based on actual test data to determine the room heatup rate for the Unit 2 emergency switchgear area following the loss of all ventilation. The results of this analysis concluded that the area would not heat up past the equipment qualification limit during a 24 hour period. Therefore, based on this analysis, Top Event "BV", which contributed 17.1% to the IPE CDF, was eliminated from the updated BVPS-2 model.
- The Unit 2 ATWS model was also revised to give full pressure relief capacity credit for each of the 3 PORVs to reduce the unfavorable exposure time and models all possible PORV alignments.

Beaver Valley Unit 2 Revision 2

This revision simply integrated the Beaver Valley Unit 2 Revision 1, Level 1 and Level 2 PRA models into a single PRA model. The internal events core damage frequency remained at 5.96E-05 / year.

Beaver Valley Unit 2 Revision 3A

Beaver Valley Unit 2 Revision 3A was an interim PRA model that was used in the NEI 00-02 PRA Peer Review process. This revision was made with the following model modifications. The changes resulted in an internal events core damage frequency of 8.50E-06 / year.

- The updated model used the latest industry methodology for determining reactor coolant pump (RCP) seal LOCAs. This methodology is based on Westinghouse WCAP-15603, Rev. 0 (Reference 21); however, it was slightly modified to account for the NRC's preliminary comments reviewing the WCAP. This modification used a number 1 seal popping-and-binding failure probability P(PB1) of 0.025 (which is the same as the Brookhaven Model) instead of 0.0125. With this new RCP seal LOCA model there was a 78-percent probability that the seal leakage would not exceed 21 gpm per RCP during the loss of all seal cooling condition, which accounts for the installed high-temperature O-rings on all three RCPs.
- The revised RCP seal LOCA frequency also included plant specific thermal hydraulic analyses performed with MAAP 4.0.4, which now accounts for sequences that do not go to core melt during a 24 hour period, given that AFW is available. These analyses were performed for both station blackout and loss of all service water scenarios.
- The initiating events data was based on Westinghouse WCAP-15210 (Reference 10) to develop a generic prior and then Bayesian updated using Beaver Valley Unit 2 actual plant experience.
- The Electric Power Recovery model, updated with the latest system models, credited more scenarios with recovery of the fast bus transfer breakers, emergency diesel generators, and offsite grid.
- The turbine driven auxiliary feedwater pump failure data was revisited to see if any previously counted failures could be eliminated from inclusion into the plant specific data update. Of the eight failures included in the previous PRA model for the ZTPTSR (Turbine driven auxiliary feedwater pump failure to run during operation) failure rate, four failures to

run were eliminated and one failure to run was reclassified as a failure to start. Of the four failures to run that were eliminated; one was a packing leak, one was an oil leak, one that required OST support was moved into another failure, and one had instructions revised so that the governor valve linkage is no longer painted. This reduced the ZTPTSR failure rate by nearly 56%.

- The reactor trip breaker failure rates were now based on NUREG/CR-5500 (Reference 22) and then Bayesian updated using a more detailed analysis of Beaver Valley Unit 2 actual plant experience.
- Motor operated valve failure rates were based on NUREG-1715 (Reference 23) to develop a generic prior and then Bayesian updated using Beaver Valley Unit 2 actual plant experience.
- The SSPS split fractions were based on a CAFTA model using BVPS-2 plant specific components and Westinghouse generic failure rates. This model was developed as part of the risk-informed application for the Unit 2 Slave Relay Surveillance Test Interval Extension.
- Each of the emergency diesel generators were assigned 2.5% of unavailability associated with them based on the current INPO/WANO industry guidelines, which was intended to provide more hours for future on-line maintenance.

<u>Beaver Valley Unit 2 Revision 3B</u>

Beaver Valley Unit 2 Revision 3B was made with the following model modifications and incorporated the PRA Peer Review resolutions to the category A and B F&Os. The changes resulted in an internal events core damage frequency of <u>2.00E-05 / year</u>.

- The revised RCP Seal LOCA frequency also included plant specific thermal-hydraulic analyses performed with Modular Accident Analysis Program (MAAP) 4.0.4, which accounted for sequences that do not go to core melt during a 48-hour period, given that AFW is available, as non-core damage sequences. These analyses were performed for both Station Blackout and loss of all service water scenarios. RCP Seal LOCA sequences that uncover the core before 48 hours, but after 30 hours, used an electric power recovery factor based on the probability of not recovering offsite power before core damage occurs using the Plant-Centered LOSP Recovery lognormal distribution reported in NUREG/CR-5496 and the median probability of not recovering at least one emergency diesel generator at times greater than 24-hours (if available for recovery).
- The initiating events data was based on WCAP-15210 to develop a generic prior and then Bayesian updated using Beaver Valley Unit 2 actual plant experience. Based on the PRA Peer Review comments, the first year of commercial operation was excluded from the Bayesian update data. Additionally, LOCA initiating event frequencies were based on the interim LOCA frequencies taken from Table 4.1 of the "Technical Work to Support Possible Rulemaking for a Risk-Informed Alternative to 10CFR50.46/GDC 35", to account for aging-related failure mechanisms.
- In response to PRA Peer Review comments on the ATWS model, operator credit to perform emergency boration was now given even if earlier actions to manually trip the reactor or insert control rods fail.
- Based on the PRA Peer Review comments, the success terms for the component failure data were revisited and checked against the Maintenance Rule estimated demands and operating time given by the System Engineers, for a 13.2 year period. Any discrepancies between that used in the BV2REV3A data were resolved and the failure data was revised using a Bayesian update process in the BV2REV3B PRA model.

- The concerns of the PRA Peer Review on the interfacing system LOCA initiating event frequency were addressed using the latest industry information from NUREG/CR-5102 and NUREG/CR-5603. Additionally, the Monte Carlo value from this revised model was used for the initiating event frequency.

Beaver Valley Unit 2 Revision 4

Beaver Valley Unit 2 Revision 4 was made with the following model modifications. The changes resulted in an internal events core damage frequency of 9.53E-06 / year.

- The emergency diesel generator unavailability was once again based on historical BVPS unavailability, since extended on-line maintenance beyond 72-hours would require the availability of an additional AC power source (e.g., spare diesel generator) capable of supplying safe shutdown loads during a station blackout, per Amendments 1A-268 & 2A-150. Therefore, it is believed that there is a low probability that the extended AOT would ever be implemented, and hence, significant emergency diesel generator unavailability should only be accrued during plant outages.
- Credit was given for the Operators to align a spare battery charger on the 125V DC Busses 2-1 and 2-2 given that their primary battery charger has failed and the batteries are supplying the bus. These actions are now directed in Alarm Response Procedures 2OM-39.4.AAD and 2OM-39.4.AAE.
- Credit was given for the main feedwater pump discharge check valves (2FWS-1 & 2FWS-2) to prevent flow diversion from the auxiliary feedwater pumps, in conjunction with the previously modeled main feedwater check valves (2FWS-28, 29, & 30).
- The alternate high head safety injection flow path through 2SIS-MOV836 was credited, given the failure of the primary high head safety injection flow path through the 2SIS-MOV867 valves.
- The third train of station instrument air, consisting of an auto start, diesel driven station air compressor was included in the PRA model. This system also provides an air supply to the containment instrument air system.
- Credit for Operators to manually initiate safety injection following a large break LOCA was given, with an associated human error probability of 2.1E-02, as opposed to an assumed guaranteed failure in previous PRA models.
- The methodology used to calculate the human error probabilities was changed from the SLIM to the EPRI HRA Calculator. These new HEPs also used operator action timings based on plant specific MAAP thermal hydraulic analysis that included the EPU and ACC.
- The updated model used the latest NRC accepted methodology for determining RCP Seal LOCAs. This methodology is based on Westinghouse's WCAP-15603, Revision 1-A, "WOG 2000 Reactor Coolant Pump Seal Leakage Model for Westinghouse PWRs." The use of this revision differs from the previous PRA model in that the 57 gpm RCP seal LOCA probability was reassigned to the 182 gpm seal LOCA, and now has a zero probability. This is due to the NRC review of the WCAP, which concluded that given the failure of the second stage seal the third stage seal failure

probability is unity, since it is not designed to handle more than the normal operating pressure differential of a few psid. However, with this new RCP Seal LOCA model there is now a 79% probability that the seal leakage will not exceed 21 gpm per RCP during the loss of all seal cooling condition, which accounts for the installed high-temperature o-rings on all three RCPs.

- The revised RCP Seal LOCA frequency also included plant specific thermal hydraulic analyses performed with MAAP DBA and accounts for full EPU conditions. RCP Seal LOCA sequences that do not go to core melt during a 48 hour period, given that AFW is available, are not counted as core damage sequences, since it is believed that alternate equipment could be provided within this time frame to maintain the reactor in a safe stable state. These MAAP analyses were performed for both Station Blackout and loss of all river (service) water scenarios.
- The initiating events data was based on Westinghouse WCAP-15210, Revision 1, “Transient Initiated Event Operating History Database for U.S. Westinghouse NSSS Plants (1987 – 1997)” to develop a generic prior and then Bayesian updated using Beaver Valley Unit 2 actual plant experience from January 1, 1989 though December 31, 2005.
- The loss of offsite power (LOSP) initiating event was broken down into five separate initiators; (1) plant-centered, (2) grid-centered, (3) switchyard centered, (4) severe weather related, and (5) extreme weather related. The basis for these initiating event frequencies comes from NUREG/CR-INEEL/EXT-04-02326, “Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1986 – 2003 (Draft),” that were Bayesian updated with BVPS-2 plant specific data.
- The offsite power restoration probability curves used in the electric power recovery analyses were also based on NUREG/CR-INEEL/EXT-04-02326 potential bus restoration data using a composite curve. The composite curve is a frequency-weighted average of the four individual LOSP category curves (it excluded the extreme weather related data), which was Bayesian updated with plant-specific LOSP frequencies. The electric power recovery factors were not credited for extreme weather related LOSP initiators.
- The consequential loss of offsite power probability following reactor trips was updated.

3.1.2 External Events

For external events, the development of a list of possible scenarios is similar to that for internal events. Because of this, the models for external events can take advantage of much of the work completed for internal events. Rather than develop new event trees for external events, use is made of the most appropriate event trees developed earlier for internal events. Only the changes needed to account for the unique aspects of the external events are required.

3.1.2.1 Internal Fires

The fire analysis employs a scenario-based approach that meets the intent of NUREG-1407 to systematically identify fire and smoke hazards and their associated risk impact to BVPS-2. The analysis was divided into two phases: (1) a spatial interactions analysis phase and (2) a detailed analysis phase. In the spatial interactions analysis phase, one or more fire and smoke hazard scenarios were developed for each plant location that can potentially initiate a plant transient or affect the ability of the plant to mitigate an accident. The scenarios developed in this phase are called location scenarios. Conservative assumptions were made in the assessment of scenario impacts to screen out location scenarios that have a relatively insignificant impact on plant safety.

In the detailed analysis phase, detailed scenarios were developed for the location scenarios that survived the spatial interactions analysis screening. One or several frequency reduction factors (geometry factor, severity factor, fire nonsuppression factor, and nonrecovery factor) were assessed for each detailed scenario. As each frequency reduction factor was assessed, conservatism introduced in the earlier phase was reduced and the complexity of the analysis progressively increased. Whenever one or more reduction factors led to the conclusion that the risk associated with a detailed scenario was relatively insignificant, the analysis for that detailed scenario would be halted. Each detailed scenario was evaluated iteratively until the scenario was considered to be relatively risk insignificant or all frequency reduction factors were assessed. The plant vulnerabilities to fire and smoke hazards were assessed by aggregating the risk impact of the subscenarios. The frequency of fire and smoke hazard-initiated core damage sequences was used as a measure of the potential for plant vulnerabilities.

The containment performance in response to fire threats, Fire Risk Scoping Study (FRSS) issues, and other special safety issues were also evaluated. Low-cost risk management options could then be identified to reduce the risk impact associated with these scenarios.

The major steps of the Beaver Valley Fire Individual Plant Examination for External Events (IPEEE) are summarized as follows:

- Phase 1: Spatial Interactions Analysis

  1. Information Gathering and Data Collection
  2. Preliminary Screening and Identification of Important Locations
  3. Development of Location Scenarios
  4. Quantitative Screening

- Phase 2: Detailed Analysis

  5. Development and Analysis of Detailed Scenarios
  6. Sensitivity/Uncertainty Analysis
  7. Containment Performance Evaluation
  8. Resolution of the FRSS and Other Safety Issues

The BVPS-2 Fire PRA has not been explicitly updated since the IPEEE. However, as the Fire sequences are dependent on internal events modeling, the Fire sequences have implicitly been partially updated with updates to the internal events models. Additionally, screened-out detailed scenarios that were considered to be relatively risk insignificant in the IPEEE, but close to the threshold (1.4E-07/yr at Unit 2), were reanalyzed and included in subsequent PRA model revisions. Results of the Fire PRA for BVPS-2 are provided in the following Table 3.1.2.1-1

Table 3.1.2.1-1: Fire PRA Results	
	BVPS-2 PRA Model
Current Fire CDF (/year)	4.80E-06
IPEEE Fire CDF (/year)	1.05E-05

Beaver Valley Unit 2 IPEEE Information

The IPEEE concluded that there are no readily apparent vulnerabilities to fire events at BVPS-2. The discussion that follows highlights the most significant contributors, in terms of how the plant might be changed to reduce the already acceptable risk.

Two general areas for improvement are considered; i.e., the equipment impacts that may result from fires in key areas, and the plant response to the most risk significant postulated fires. The current controls in place at BVPS-2 are judged to be adequate to limit the frequency of fires from internal plant sources.

The extent of equipment impacted by a fire depends on the originating location and to a large extent, the amount and arrangement of cables within the rooms affected. For many of the key fire subscenarios identified, the equipment impacts are limited. For example, both trains of service water may be disabled by the fire, but there may be no other plant impacts. For such scenarios, repositioning of equipment or the rerouting of selected cables may be effective at reducing the risks of core damage.

Possible changes that might affect the frequency of the top five fire subscenarios that account for almost 53% of the fire-initiated CDF are discussed below and are presented in Table 3.1.2.1-2 (extracted from Table 7-1 of the BVPS-2 IPEEE) for BVPS-2. The frequency assessment of the key scenarios is consistent with the analysis in Appendix R, in that, for the key scenarios, it accounts for operator recovery actions that may have been credited in the Appendix R analysis.

Table 3.1.2.1-2: BVPS-2 IPEEE Model/Design Enhancements

CDF Key Contributor	Model or Design Enhancement	IPEEE CDF Importance		Percent of Total CDF **	Status
		Percent of CDF	Risk Reduction Worth *		
Emergency AC Power	Reevaluate diesel generator building fragility.	58.3 (Seismic)	0.7110 (Seismic)	4.1	The diesel generator building HCLPF is 0.28g, more than twice the SSE level. This along with a low contribution to total CDF warrants no further action.
CB-3 Fire	Provide operator credit for recovery of auxiliary feedwater from outside of control room.	17.8 (Fire)	0.79062 (Fire)	2.5	The low contribution to total CDF warrents no further action. This evaluation is consistent with the BVPS-1 analysis. However, the operator recovery credit could change if deemed necessary.
CT-1 Fire	Install qualified fire barriers between fire areas CB-1, CB-2 and CT-1.	12.6 (Fire)	0.9941 (Fire)	1.8	The low contribution to total CDF warrents no further action.
SB-4 Fire	Install an automatic CO2 fire supression system.	10.5 (Fire)	0.9380 (Fire)	1.4	The low contribution to total CDF warrents no further action.
CV-1 Fire	Reroute purple train service water pump/MOV power and control cables.	6.2 (Fire)	0.9941 (Fire)	0.9	The low contribution to total CDF warrents no further action.
CV-3 Fire	Reroute orange train CCP/thermal barrier cooling MOV and service water power and control cables.	5.8 (Fire)	0.9986 (Fire)	0.8	The low contribution to total CDF warrents no further action.

Notes: * The Risk Reduction Worth is the factor decrease in CDF that would be realized if the failure probability of the affected contributor was decreased to 0.0 (i.e., guaranteed success). ** Total CDF includes both internal and external events.

3.1.2.2 Seismic Events

A PRA was performed for internal initiating events on the Beaver Valley Power Station in satisfaction of the IPE requirements. To assess the risk contribution and significance of seismic-initiated events to the total plant risk, it was determined that the PRA method should also be used for the seismic analysis to meet the requirements of the IPEEE.

Beaver Valley selected the Seismic PRA option over the seismic margins option for the following reasons:

- With the existing PRAs for internal events that were developed to support the IPE and the decision to extend the PRA for all of the external events within the IPEEE scope, all severe accident issues are addressed within the context of an integrated PRA model that consistently treats all internal and external initiating events. This model rigorously accounts for all accident sequences resulting from any combination of internal and external events. The resulting risk information provided from this integrated approach was viewed as more useful to DLC management to make decisions about allocating resources to manage the risks of severe accidents.

- With the ability to link the Level 1 and Level 2 event trees as demonstrated in the IPE, the selected PRA approach was found to provide a more rigorous examination of potential containment vulnerabilities and seismic/systems interactions impacting containment effectiveness than was possible using the seismic margins approach.

The methodology selected is consistent with PRAs performed with the procedures contained in NUREG/CR-2300. In general, the methodology used in the analysis consisted of the following main steps:

- Seismic Hazard Analysis**.** Determination of the frequency of various potential peak ground accelerations (PGA) at the site, and an assessment of the likelihood of landslides and soil liquefaction.

- Fragility Analysis**.** Determination of the conditional failure probability of risk-related plant structures and components at peak ground accelerations.

- Plant Logic Analysis. Development of logic models that evaluate the potential structure and component failure scenarios. The models include seismic-induced failures that may initiate an accident scenario and may directly disable components or systems needed to successfully terminate the scenario. The models also include potential failures and unavailabilities of components due to nonseismic causes.

- Level 1/2 Integration. The linking of Level 1 seismic event trees with the Level 2 containment event tree for an integrated Level 2 PRA of seismic events and seismic/system integrations to examine containment effectiveness.

- Assembly and Quantification. Assembly of the seismic hazard, component fragilities and nonseismic unavailabilities, and plant logic models, including model quantification to obtain point estimates for core damage, plant damage state, release category, and scenario frequencies that result from seismic-initiated events.

- Uncertainty Quantification. Calculation of probability distributions for category (Level 2 results) and core damage frequencies (Level 1 results) that can be combined with the results from other initiating events.

The BVPS-2 Seismic PRA has not been explicitly updated since the IPEEE. However, as the seismic sequences are dependent on internal events modeling, the seismic sequences have implicitly been partially updated with updates to the internal events models. Additionally, BVPS-2 Revision 3A PRA model revised the component seismic fragilities based on the September 10, 1999 response to the Nuclear Regulatory Commission's IPEEE Request for Additional Information, dated July 8, 1999. This response noted that following a review of the analysis, the BVPS median capacities for those structures and equipment for which the seismic fragilities were directly calculated were overestimated by approximately 36%. Incorporating these new component fragilities resulted in the modeling of additional Seismic Top Events, as well as, increasing the failure probabilities. Results of the Seismic PRA for BVPS-2 are provided in the following Table 3.1.2.2-1

Table 3.1.2.2-1: Seismic PRA Results

	BVPS-2 PRA Model
Current Seismic CDF (/year)	9.70E-06
IPEEE Seismic CDF (/year)	5.33E-06 (Original) 1.03E-05 (RAI Revised)

Beaver Valley Unit 2 IPEEE Seismic Information

The IPEEE concluded that there are no readily apparent vulnerabilities to seismic events at BVPS-2. The discussion that follows highlights the most significant seismic contributors, in terms of what might be changed to reduce the already acceptable risk. Two general areas for improvement were considered; (1) the plant response to seismic-initiated failures, and (2) the equipment seismic fragilities.

For all but 2 of the top 50 highest frequency core damage sequences in the original IPEEE submittal, the conditional probability of core damage given the seismic initiating event and failures directly attributable to it are all 1.0. In the large majority of these sequences, either the seismic failures result in a station blackout, or the loss of all service water. In some of the top sequences, there may be two or more failures, which if they occurred alone, would each result in core damage. In the 2 sequences, which are an exception to the above, the seismic failure of the normal 4KV AC and 125V DC busses places a demand on the emergency diesel generators. The non-seismic, probabilistic failures of the diesel generators then result in a station blackout, given that the Unit AC power crosstie is unavailable due to the seismic failure of the normal 4KV busses. The CDF contribution from these 2 sequences is about 4.41E-08. Moreover, the total CDF from all similar sequences is only 1.75E-07. Therefore, it is concluded that options to improve the plant response to seismic events would not be effective in limiting risk. This conclusion was also reached in the IPEEE RAI response.

The offsite power grid, the 125V DC ERF Substation batteries, and the station air compressors/turbine building block walls are assessed as having the lowest fragility curves of those modeled. However, the most risk significant seismic fragility is that of the 4KV emergency bus transformers and diesel generators/DG building. Failures of these SSCs are assumed to result in the loss of emergency AC power and result in a station blackout leading to eventual core damage. Although enhancements to these SSCs could reduce the seismic CDF by almost 29%, they are not considered feasible since their HCLPF values exceed 0.28g (or more than twice the BVPS-2 SSE value of 0.125g) and the seismic CDF contribution is already low when compared to the internal events CDF.

These recommended enhancements to BVPS-2 are summarized in Table 3.1.2-1 (extracted from Table 7-1 of the BVPS-2 IPEEE).

Beaver Valley Unit 2 USI A-45 Resolution

Resolution of the external events portion of Unresolved Safety Issue A-45 was subsumed into the IPEEE requirements that allow plant-specific evaluation of the safety adequacy of decay heat removal systems.

The Beaver Valley Unit 2 PRA results do provide indications of the importance of systems that directly perform the decay heat removal function. The IPEEE indicated the importance of systems that perform the decay heat removal function. Five classes of systems were considered: main feedwater, auxiliary feedwater, bleed and feed cooling, steam generator depressurization for RCS cooldown, and closed loop residual heat removal. Importance was measured by the percentage of core damage frequency attributable to sequences that involve failure of the indicated split fraction. The importance measures are not additive because more than one of the ranked split fractions may, and often do, fail in the same sequence.

Two event tree top events are used to represent the main feedwater system. Top Event “MF” represents the hardware failure modes under normal operations and Top Event “OF” represents the operator action to realign main feedwater after a plant trip, given that auxiliary feedwater fails. All of the main feedwater system hardware failures occur in sequences in which main feedwater is lost due to the seismically caused loss of its support systems, i.e., split fraction MFF. Failure of the operators to realign main feedwater after the plant trip is dominated by earthquakes with PGAs above 0.5g.

Top Event “AF” represents the auxiliary feedwater system. The most important auxiliary feedwater system failures are due to operators failing to provide makeup water to the auxiliary feedwater pumps after the depletion of supply tank 2FWE-TK210 for earthquakes with PGAs above 0.5g. The next most important auxiliary feedwater system failures are failures of the turbine driven pump given loss of electrical support to the motor driven pumps.

Feed and bleed cooling is modeled by three separate event tree top events: Top Event “HH” for the HHSI pumps and flow path from the RWST, Top Event “HC” for the cold leg injection flow path, and Top Event “OB” that models the bleed path via the pressurizer. Because of the credit taken for realigning the electric-driven main feedwater pumps, the Beaver Valley Unit 2 design minimizes the frequency of sequences involving failure of AFW and bleed and feed cooling, relative to other PWRs. Two of these three top events (“HC” and “HH”) are also used to model high head safety injection in the event of a small LOCA.

Top Event “CD” models the action to depressurize the steam generators in sequences where it is desirable to cool down and depressurize the RCS. Steam generator depressurization helps to limit RCS leakage during a station blackout or a steam generator tube rupture with a stuck-open secondary side valve. It is also used during small LOCAs in order to inject water into the reactor core with the low head safety injection pumps given the failure of the high head safety injection pumps. As can be seen from the percentage of contribution listed in IPEEE Table 3-18, such failures are relatively unimportant to the core damage frequency.

Finally, the importance of cooling via the residual heat removal system is also indicated in IPEEE Table 3-18. The RHR system plays only a minor role in the determination of the core melt frequency. By design, this system is tripped off on a Phase B containment isolation signal. No sequences greater than 1.6E-09 per year involved failure of the RHR.

In summary, no particular vulnerabilities of the Beaver Valley Unit 2 systems that are used to perform decay heat removal were identified. The majority of the seismic core damage frequency at Beaver Valley Unit 2 comes from the loss of emergency AC power caused by the seismic initiating event or failure of operator actions following earthquakes with PGAs above 0.5g. No discernible frequency comes from failures of decay heat removal.

3.1.2.3 Other External Events

NUREG-1407 recommends a screening type approach, as shown in Figure 3.1.2.3-1 (taken from Figure 5-1 of NUREG-1407), to evaluate the external hazards included in this section. The general methodology used at BVPS-2 follows the approach recommended by NUREG-1407 and consists of the following steps:

- Establishing a List of Plant-Specific Other External Events
- Progressive Screening
- Walkdown
- Documentation

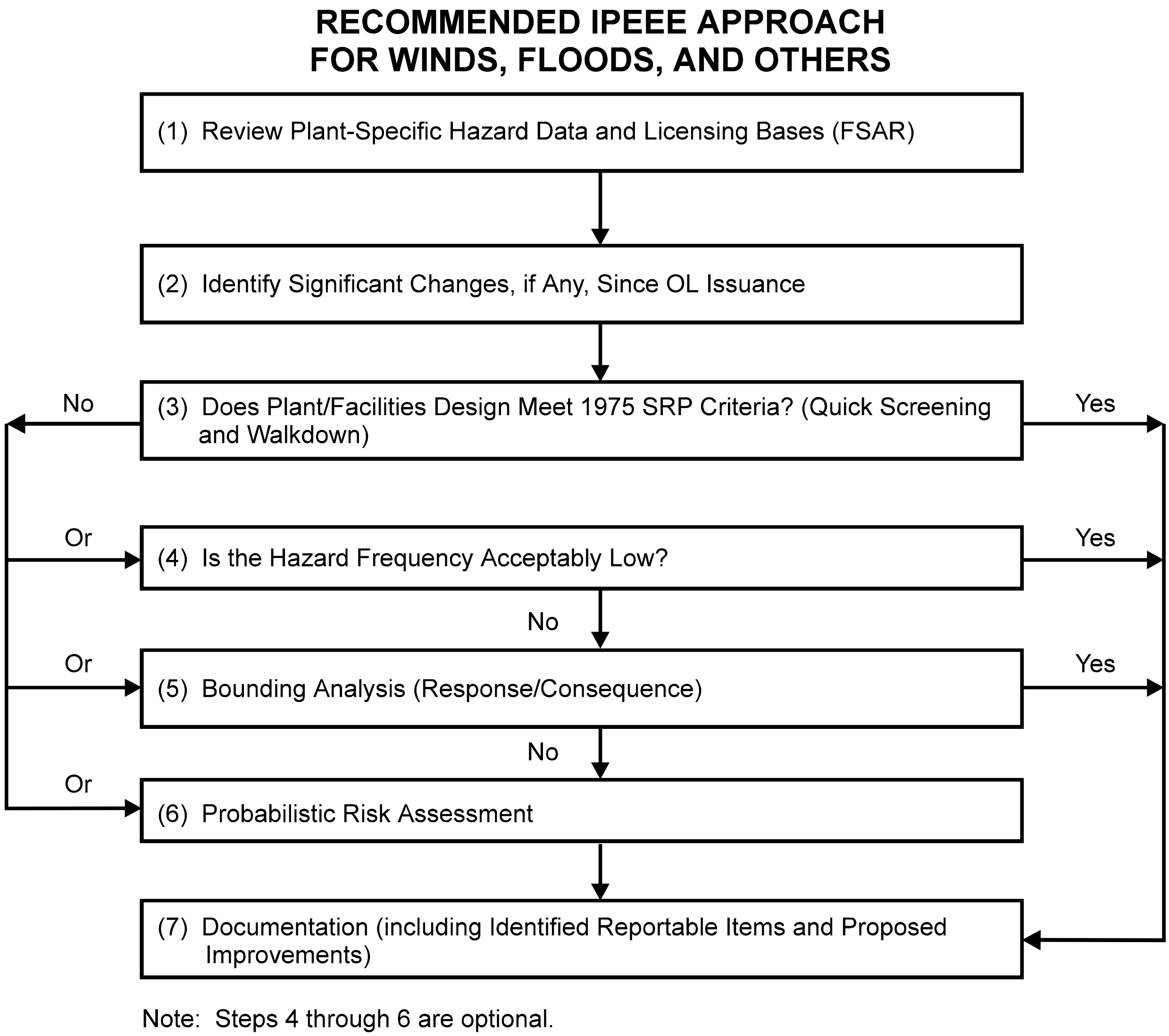

Figure 3.1.2.3-1: NUREG-1407 Screening Approach

Based on the results in the BVPS-2 IPEEE, it was concluded that the plant structures at the site are well designed to withstand the high wind associated hazards and that no potential vulnerability is identified.

Since the plant and facilities design meets the 1975 SRP criteria, and that there are no existing plant changes that could affect the plant hazard data or the licensing bases with respect to flooding, the core damage frequency due to external flooding was estimated to be less than 1.0E-06 per year for BVPS-2.

The NRC staff concluded, in the BVPS-2 IPEEE SER, that, according to GDC 4, GDC 19, and SRP Section 2.2.3, the BVPS plant is adequately protected and acceptable with respect to transportation and nearby facility hazards.

Based on the review of the lightning events that have occurred at the site, it was concluded that they were less severe than a complete loss of offsite power to BVPS-2. Also, according to Section 2.6 of NUREG-1407, the probability of a severe accident caused by lightning would be relatively low. Therefore, lightning is an insignificant contributor to core damage frequency for BVPS-2.

The contribution to the BVPS-2 total CDF from the other external events is less than 1.0E-06 per year, and as concluded in the BVPS-2 IPEEE, there are no vulnerabilities to the other external events at BVPS-2.

3.1.2.4 External Event Severe Accident Risk

External event severe accident risk assessment is integrated with the internal events risk; the PRA includes both internal and external. This assessment approach provides the means to evaluate SAMAs for both internal and external events impacts simultaneously without the need to separately estimate the impact of the potential improvements on external events.

3.2 LEVEL 2 PLANT SPECIFIC MODEL

The Level 2 PRA model determines release frequency, severity, and timing based on the Level 1 PRA, containment performance, and accident progression analyses.

3.2.1 Description of Level 2 PRA Model

The accident sequence analysis defines the manner in which expected plant response to each identified initiating event or initiating event category is represented and quantified. This accounts for successes and failures of safety functions and related systems, and human actions to determine whether or not core damage occurs. The result of the Level 1 accident sequence analysis is the definition of a set of event trees used to represent and quantify the accident sequences.

The Level 2 analysis extends the Level 1 analysis to investigate the release category potential for core damage end states found. A containment event tree is used to represent and quantify the LERF potential when quantified with the Level 1 event trees.

The Level 2 analysis is highly interdependent with other PRA tasks. The accident sequence plant damage states define the categories of core damage sequences to be considered in the Level 2 analysis. The event tree used to represent and quantify the LERF potential is linked to the event trees representing the Level 1 analysis.

Each end state of the plant model (front-end or Level 1) event trees defines an accident sequence that results from an initiating event followed by the success or failure of various plant systems and/or the success or failure of operators to respond to procedures or otherwise intervene to mitigate the accident. Each accident sequence has a unique signature due to the particular combination of top event successes and failures. Each accident sequence that results in core damage could be evaluated explicitly in terms of the accident progression and the release of radioactive materials, if any, into the environment. However, since there can be millions of such sequences, it is impractical to perform thermal-hydraulic analyses and CET split-fraction quantification for each accident sequence. Therefore, for practical reasons, the Level 1 sequences are usually grouped into PDS (or accident class) bins, each of which collects all of those sequences for which the progression of core damage, the release of fission products from the fuel, the status of the containment and its systems, and the potential for mitigating source terms are similar. A detailed split-fraction analysis is then focused on specific sequences selected to represent risk-significant bins.

PDS bins have been used as the entry states (similar to initiating events for the plant model event trees) to the CETs. The PDS bins are characterized by thermodynamic conditions in the RCS and the containment at the onset of core damage, and the availability or unavailability of both passive and active plant features that can terminate the accident or mitigate the release of radioactive materials into the environment.

However, this was not the case in the BVPS-2 PRA models, where the CET was linked directly to the Level 1 trees to generate the frequencies of the defined release categories. Although the CET was linked directly to the Level 1 trees, the concept of PDSs was retained to minimize the number of CET top event split fractions that must be calculated. Furthermore, the CET was quantified separately for a number of key PDSs to facilitate debugging of the rules used for assigning CET split fractions and binning sequences to appropriate release categories.

The PDSs are characterized in such a manner to facilitate Level 2 quantification. However, the core damage frequency need not be characterized using the same PDS bins. In fact, Level 1 results have been characterized using much broader bin definitions.

Representative accident sequences must be selected to quantify split-fraction values for the CET. If PDSs are defined, a representative accident sequence(s) is selected for each risk-significant

PDS. These representative sequences are analyzed in detail with appropriate thermal-hydraulic and fission product transport codes such as the Modular Accident Analysis Program, the Source Term Code Package, and/or the MELCOR program to characterize the timing of important events (such as the onset of severe core damage and reactor vessel melt-through) as well as the nature of the core damage, containment failure, and fission product release.

The BV2REV4 PDS groups are presented in Table 3.2.1-4.

PDS groups are evaluated in a Containment Event Tree. CET sequences are then grouped and binned in previously defined release category bins based on sequence and containment conditions as shown in Table 3.2.1-5 (Table 4.7-7 in the BVPS-2 IPE Summary Report submittal).

The IPE source term evaluation was based on radionuclide releases of 20 Beaver Valley release category bins plus an intact containment bin. However, in support of the SAMA, BVPS has elected to upgrade the source release fractions for select bounding release categories based on current plant specific MAAP-DBA analyses that account for EPU conditions. In support of SAMA evaluations it is not necessary to run a MAAP case to represent each individual IPE release class for BVPS (i.e., BV1 – BV21). The release categories identified in Table 3.2.1-6 are those that are applicable to the plant’s Level 3 and SAMA evaluations and were re-evaluated using MAAP-DBA. The specific MAAP cases provided in the table were judged to be sufficient to represent each release category identified in the BVPS SAMA evaluation.

All MAAP-DBA cases were analyzed for 24 hours after the time of release, or demonstrated that a complete release has been produced (i.e., at least 98% of the noble gases have been released from containment).

The Level 2 quantification extends the Level 1 results of the Beaver Valley Unit 2 PRA to include the Level 2 results. This extension has been accomplished by linking the CET (discussed earlier in this section) to the Level 1 trees, and by assigning the end states of the linked Levels 1 and 2 trees to the appropriate release categories. For reporting, the release categories have been binned into four groups, as shown in Table 3.2.1-1. Basic Event Importances (Table 3.2.1-2) and Component Importances (Table 3.2.1-3) for the Large Early Release category group are provided for information.

Table 3.2.1-1: BV2REV4 Release Category Group Definition and Results

Release Type	Description	Associated CDF (per year)	Percentage of Total CDF
I	Large, early containment failures and bypasses	4.09E-07	1.7%
II	Small, early containment failures and bypasses	3.81E-06	15.9%
III	Late containment failures	1.86E-05	77.4%
IV	Long-term contained releases (intact containment)	1.20E-06	5.0%
Total Plant CDF		2.40E-05	100%

Table 3.2.1-2: BV2REV4 Basic Event Importances for Total Plant LERF by Risk Reduction Worth

Rank	Basic Event Name	Basic Event Description	RRW*	Applicable SAMA
1	OGXXXX	Offsite Grid Fails Following Non-LOSP Initiator	1.14E+00	AC Power SAMAs
2	OPRSL1	Operator Fails to Identify Ruptured Steam Generator or Initiate Isolation	1.14E+00	SAMA 178
3	OPROS1	Operator Fails to Initiate SI Following Steam Line Break	1.07E+00	SAMA 153
4	OPRSL3	Operator Fails to Gag Stuck Open SRV	1.07E+00	SAMA 164
5	[CBFC4KVS2A2A4 CBFC4KVS2D2D7]	CCF of SSST Incoming Circuit Breakers	1.04E+00	AC Power SAMAs
6	OPRSL2	Operator fails to locally close or isolate secondary relief valve	1.02E+00	SGTR SAMAs
7	OPRWM1	Operator Fails to Align Makeup to RWST - SGTR, Secondary Leak PR	1.02E+00	SAMA 169
8	EVFC2SVSHCV104	Residual Heat Release Valve 2SVS-HCV104 Fails to Close on Demand	1.02E+00	SGTR SAMAs
9	LHSI_PIPE_R	LHSI Pipe Rupture Given RCS Leak Rate to LPI Greater than 150 gpm	1.02E+00	LOCA SAMAs
10	SCENARIO1	Three cold Leg Check Valves Rupture	1.01E+00	SAMA ISLOCA

* The Risk Reduction Worth (RRW) is defined by the following Fussell-Vesley (FV) relationship:
RRW = 1 / (1 - FV)

Table 3.2.1-3: BV2REV4 Component Importances for Total Plant LERF by Risk Reduction Worth				
Rank	**Component Name**	**Component Description**	**RRW**	**Applicable SAMA**
1	2SVS-HCV104	Residual Heat Release Valve	1.02E+00	SGTR SAMAs
2	4KVS-2D-2D7	Incoming Supply Feed From TR-2B for Bus 2D (ACB-342B)	1.01E+00	AC Power SAMAs
3	2MSS-SV101C	(2RCS*SG21C) Main Steam Safety Valve	1.01E+00	SGTR SAMAs
4	2MSS-SV102C	(2RCS*SG21C) Main Steam Safety Valve	1.01E+00	SGTR SAMAs
5	2MSS-SV103C	(2RCS*SG21C) Main Steam Safety Valve	1.01E+00	SGTR SAMAs
6	2MSS-SV101A	(2RCS*SG21A) Main Steam Safety Valve	1.01E+00	SGTR SAMAs
7	2MSS-SV102A	(2RCS*SG21A) Main Steam Safety Valve	1.01E+00	SGTR SAMAs
8	2MSS-SV103A	(2RCS*SG21A) Main Steam Safety Valve	1.01E+00	SGTR SAMAs
9	2MSS-SV101B	(2RCS*SG21B) Main Steam Safety Valve	1.01E+00	SGTR SAMAs
10	2MSS-SV102B	(2RCS*SG21B) Main Steam Safety Valve	1.01E+00	SGTR SAMAs
* The Risk Reduction Worth (RRW) is defined by the following Fussell-Vesley (FV) relationship: RRW = 1 / (1 - FV)				

Table 3.2.1-4
BV2REV4 Level 1 Sequence Groupings

RCS Pressure at Core Damage	Containment Bypassed		Containment Not Isolated	Containment Isolated	
	Small (SBYP)	Large (LBYP)		With Heat Removal (WCHR)	No Heat Removal (NOHR)
Low (L)) (0-200 psia)	LOSBYP	LOLBYP	LONISO	LOWCHR	LONOHR
Medium (MD) (200-600 psia)	MDSBYP	--	MDNISO	MDWCHR	MDNOHR
High (HI) (600-2,000 psia)	HISBYP	--	HINISO	HIWCHR	HINOHR
System Setpoint (SY) (>2,000 psia)	SYSBYP	--	SYNISO	SYWCHR	SYNOHR

Table 3.2.1-5 Beaver Valley Unit 2 PRA Release Categories

Release Category	RCS Pressure: High	RCS Pressure: Med	RCS Pressure: Low	Containment Failure: Intact	Containment Failure: Early	Containment Failure: Late	Containment Failure: Large	Containment Failure: Small	Containment Failure: Lrg Byp	Containment Failure: Sm Byp	Sprays?: Yes	Sprays?: Partial	Sprays?: No	Ex-Cont Retention*: None	Ex-Cont Retention*: Mod-erate	Ex-Cont Retention*: Signif-icant	Draft NUREG-1150 Dry PWR Cat	Major Release Type**
BV1	X				X		X						X	X			1, 6, 16	I
BV2	X				X		X				X——	X		X			2, 7, 17	I
BV3		X	X		X		X						X	X			3, 5, 6, 18	I
BV4		X	X		X		X				X——	X		X			4, 7, 19	I
BV5	X——	X			X			X				X——	X		X		6	
BV6	X——	X			X			X			X				X		7	II
BV7			X		X			X				X——	X		X		6	
BV8			X		X			X			X				X		7	
BV9	X——	X				X	X						X	X			9	
BV10	X——	X				X	X				X——	X		X			8	
BV11			X			X	X						X	X			9	
BV12			X			X	X				X——	X		X			8	
BV13	X——	X				X		X				X——	X		X		10	III
BV14	X——	X				X		X			X				X		10	
BV15			X			X		X				X——	X		X		10	
BV16			X			X		X			X				X		10	
BV17	X——	X——	X			X		X			X——	X——	X			X	13, 14	
BV18	X——	X——	X						X	X	X——	X——	X	X			12	I
BV19			X						X		X——	X——	X		X		11	
BV20	X——	X								X	X——	X——	X			X	11	II
BV21	X——	X——	X	X							X			X			15–No Failure	IV

* "None" = direct or nearly direct to atmosphere (DF < 2), "Moderate" = through large building or with limited flooding (DF = 2 to 10), "Significant" = through deep pool or isolated steam generator (DF > 10)

** I = Large, Early Release, or Bypass, S/T equal to or greater than PWR4 (WASH-1400)
II = Small, Early Release, S/T less than PWR4 (WASH-1400)
III = Late Release, very low S/T
IV = Long-Term Containment Integrity, Minimal Release
X------X Indicates that the Release Category groups together two or more different characteristics

Table 3.2.1-6: BVPS Release Categories Reanalyzed Using MAAP-DBA			
Release Category	**IPE Release Category Description**	**Representative MAAP Accident Sequence**	**Assumed Containment Failure Area**
BV1	High RCS Pressure, Early, Large, No CHR.	SBO with no AFW and no sprays available. Large containment failure.	1 ft^2
BV3	Med/Low RCS Pressure, Early, Large, No CHR.	LLOCA with no active injection and no sprays. Large containment failure.	1 ft^2
BV5	High/Med RCS Pressure, Early, Small, Partial/No CHR, Yes Aux. Building.	SBO with no AFW and no sprays available. LOCI with a small release through the aux. building.	0.1 ft^2
BV7	Low RCS Pressure, Early, Small, Partial/No CHR, Yes Aux. Building.	LLOCA with no active injection and no sprays. LOCI with a small release through the aux. building.	0.1 ft^2
BV9	High/Med RCS Pressure, Late, Large, No CHR.	SBO with no AFW and no sprays available. Large containment failure due to over-pressurization.	1 ft^2
BV10	High/Med RCS Pressure, Late, Large, Partial CHR.	TLOFW with no active injection and partial sprays available. Large containment failure from H_2 burn.	1 ft^2
BV12	Low RCS Pressure, Late, Large, Partial CHR.	LLOCA with no active injection and partial sprays available. Large containment failure from H_2 burn.	1 ft^2
BV13	High/Med RCS Pressure, Late, Small, Partial/No CHR, Yes Aux. Building.	SBO with no AFW and no sprays available. Small containment failure due to over-pressurization.	0.2 ft^2
BV15	Low RCS Pressure, Late, Small, Partial/No CHR, Yes Aux. Building.	LLOCA with no active injection and no sprays available. Small containment failure due to over-pressurization.	0.2 ft^2
BV17	High/Med/Low RCS Pressure, Late, Small, Yes/Partial/No CHR, Ground.	SBO with no AFW and no sprays available. Failure through base of containment.	1 ft^2
BV18	High/Med/Low RCS Pressure, Large/Small Bypass, Yes/Partial/No CHR, Little or No Ex-Cont Retention.	SGTR with a TLOFW, no active injection and no sprays available. Direct release through stuck open MSSVs,	Containment Bypassed (DF=1.0)
BV19	Low RCS Pressure, Large Bypass, Yes/Partial/No CHR, Moderate Ex-Cont. Retention.	Large ISLOCA through low pressure injection system, no injection and no sprays available. Aux. building release below water level (flooded building provides scrubbing).	Containment Bypassed (DF=4.3)
BV20	High/Med RCS Pressure, Small Bypass, Yes/Partial/No CHR, Significant Ex-Cont. Retention.	Small ISLOCA through low pressure injection system, no injection and no sprays available. Aux. building release below water level (flooded building provides scrubbing).	Containment Bypassed (DF=10)
BV21	High RCS Pressure, Intact Containment, CHR available.	SLOCA with a TLOFW, no injection during recirculation and sprays available. No containment failure.	2.5E-05 ft^2 (Based on 0.1% volume / day leakage)

3.2.2 Level 2 PRA Model Changes Since IPE Submittal

The major Level 2 changes incorporated into each revision of the Beaver Valley Unit 2 PRA model are discussed below. The individual affect on risk by incorporating each of these changes has not been analyzed.

Beaver Valley Unit 2 Revision 0

This revision represents the base case IPE quantification and resulted in a large early release frequency of 8.44E-06 / year for internal events.

Beaver Valley Unit 2 Revision 1

This revision represents the base case IPEEE PRA model. There was only 1 major Level 2 change incorporated into this updated BVPS-2 PRA model. This change was implemented due to a reevaluation of the impact of direct containment heating (DCH) on the frequency of large, early releases at Beaver Valley Units 1 and 2.

The Direct Containment Heating issue was identified in the NRC's Revised Severe Accident Research Plan as an important issue for resolution because of its potential for early containment failures. DCH was recognized to be a potential by which sensible heat energy can be transferred directly to the reactor vessel and subsequent blowdown of the molten debris and RCS fluids into the containment atmosphere. If the RCS pressure is sufficiently high, the blowdown of the RCS fluid through an opening in the bottom head of the reactor vessel can entrain molten core debris in the high-velocity blowdown gas and eject fragmented particles from the reactor cavity into the containment. This series of events is referred to as high pressure melt ejection.

The Beaver Valley IPE submittals were based on an understanding of DCH phenomena as it was portrayed in the documentation (NUREG-1150 and NUREG/CR-4551) for the NRC's probabilistic assessment of severe accidents of five plants. Since that time, the state of knowledge regarding DCH phenomena evolved as additional experiments and analyses were performed. Two subsequent reports, NUREG/CR-6109 (Reference 17) and NUREG/CR-6338 (Reference 18) were issued by the NRC that relate to the resolution of DCH for Westinghouse plants with large, dry containments, including the Beaver Valley subatmospheric containments.

The conclusion of these reports is that the intermediate compartment traps most of the debris dispersed from the reactor cavity and that the thermal-chemical interactions during this dispersal process are limited by the incoherence in the steam blowdown and melt entrainment process.

Based on these new reports, the split fraction values for determining large, early containment failures (i.e., the product of C2 and L2) have reduction factors ranging from approximately 42 to more than 30,000 when compared to the IPE submittal.

This change to the Level 2 model contributed to a large early release frequency of 9.05E-07 / year for internal events.

Beaver Valley Unit 2 Revision 2

This revision simply integrated the Beaver Valley Unit 2 Revision 1, Level 1 and Level 2 PRA models into a single PRA model. The internal events large early release frequency remained at 9.05E-07 / year. There were no changes to the Level 2 PRA model.

Beaver Valley Unit 2 Revision 3A

Beaver Valley Unit 2 Revision 3A was made with the following model modifications. These changes contributed to a large early release frequency of 5.10E-07 / year for internal events.

There were four major Level 2 changes incorporated into the updated Beaver Valley Unit 1 PRA model. Three of the changes dealt with sequences involving induced SGTRs, large containment failures due to early hydrogen burns, and large containment failures due to alpha-mode (in-vessel steam explosions). Based on Westinghouse and industry state-of-the-art knowledge of these containment phenomenologies, it was then believed that the probabilities of these occurring was extremely low for large, dry containments (that is, non ice-condenser) and was not credible in large containment failures or bypasses.

The fourth change reclassified all early SGTR core damage sequences with wet SGs (i.e., auxiliary feedwater available) as small early releases without regard to break location or other sequence specific conditions such as SG isolation, primary to secondary pressure equalization, etc., based on significant fission product release scrubbing.

Beaver Valley Unit 2 Revision 3B

Beaver Valley Unit 2 Revision 3B was made with the following model modification. This change contributed to a large early release frequency of 1.14E-06/ year for internal events.

Based on the PRA Peer Review comments, the SGTR sequences were again reclassified so that only those that have a depleted RWST or have a loss of all secondary cooling were considered to be LERF contributors. It was assumed that leakage from the RCS would continue indefinitely through the faulted steam generator and the core will uncover after the RWST depletes. This is in agreement with WCAP-15955, “Steam Generator Tube Rupture PRA Notebook”.

Beaver Valley Unit 2 Revision 4

There were no specific changes to the Beaver Valley Unit 2 Level 2 model in this revision. Changes to the Level 1 model resulted in a large early release frequency of 4.06E-07/ year for internal events.

Based on a review that was performed to identify the effects of the EPU and the contributors to the Large Early Release conditional probability, there were no Level 2 changes required due to the BVPS-2 containment conversion. The sub-atmospheric containment modeling in the previous BVPS-2 PRAs assumed no large pre-existing containment isolation failures, due to the inability to maintain a containment vacuum. This assumption remains valid for EPU and the slightly subatmospheric conditions now existing, as the containment vacuum pumps are not expected to maintain the slightly sub-atmospheric condition for large pre-existing containment isolation failures, as well.

However, there were two major contributors to the reduction in the Level 2 LERF incorporated into the updated BVPS-2 PRA model. These changes dealt with sequences involving steam generator tube ruptures with stuck-open safety valves. In the PRA model, only steam generator tube ruptures that are faulted and have a depleted RWST or have a loss of all secondary cooling are considered to be LERF contributors. For these sequences it is assumed that leakage from the RCS would continue indefinitely through the faulted steam generator and the core would uncover after the RWST depletes. These assumptions are in agreement with WCAP-15955, “Steam Generator Tube Rupture PRA Notebook” (Reference 19). Therefore, by lowering the probability of having a stuck-open steam generator safety valve on the ruptured steam generator, it would reduce the LERF. The Level 1 model changes that were implemented involve reducing the probability of having a stuck-open steam generator safety valve on the ruptured steam generator. These include making an assumption that only three of the five safety valves on a ruptured steam generator would lift in response to the pressure spike (based on simulator experience), and crediting operators to gag any safety valves that stick open with an associated human error probability of 2.1E-01.

3.3 MODEL REVIEW SUMMARY

Regulatory Guide (RG) 1.174 (Reference 38), Section 2.2.3 states that the quality of a PRA analysis used to support an application is measured in terms of its appropriateness with respect to scope, level of detail and technical acceptability, and that these are to be commensurate with the application for which it is intended.

The PRA technical acceptability of the model used in the development of this Severe Accident Mitigation Alternatives application has been demonstrated by a peer review process. The peer review was conducted in July 2002, by the [former] Westinghouse Owner’s Group, with the final documentation of the review issued in December 2002. The overall conclusions of the peer review were:

> All of the technical elements were graded as sufficient to support applications requiring the capabilities defined for grade 2. The BVPS PRA thus provides an appropriate and sufficiently robust tool to support such activities as Maintenance Rule implementation, supported as necessary by deterministic insights and plant expert panel input.
>
> All 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 but in some cases this is contingent upon implementation of recommended enhancements.

After the peer review, the preliminary Category A and B facts and observations that potentially impacted the model were entered into the BVPS Corrective Action Program, dispositioned, and incorporated into updated PRA model. Although the facts and observations were written for the BVPS-2 model, if applicable, the resolution was applied to the BVPS-1 model as well. Those models have since undergone another revision, but the incorporated resolution of Category A and B facts and observations were maintained in the revision. The BVPS-2 Category A facts and observations (F&Os) and dispositions are summarized in the following paragraphs.

In addition, FENOC provided summaries of the BVPS Peer Review Category A and B F&Os in the following previously docketed letters:

- Pearce/USNRC, Beaver Valley Power Station, Unit No. 2, BV-2 Docket No. 50-412, License No. NPF-73, Response to a Request for Additional Information in Support of License Amendment Requests No. 180, dated October 24, 2003, Serial L-03-160.
- Pearce/USNRC, Beaver Valley Power Station, Unit No. 1 and No. 2, BV-1 Docket No. 50-334, License No. DPR-66 and BV-2 Docket No. 50-412, License No. NPF-73, Response to a Request for Additional Information in Support of License Amendment Requests Nos. 306 and 176, dated October 29, 2004, Serial L-04-141.

<u>**Category A Observations**</u>

F&O 1
Summary: This observation was identified in the Accident Sequence Analysis Sub-element regarding the RCP seal LOCA model. It was recognized that the BVPS RCP seal LOCA model used the WOG 2000 as a basis, but in a way that is more optimistic than most other Westinghouse plants. The BV2REV3A PRA model, RCP seal LOCA success criteria was developed from best estimate MAAP runs performed specifically for BVPS-2. Since certain MAAP results did not go to core uncovery in the assumed 24-hour mission time for the smaller break seal LOCA sizes, they were binned into the success (non CDF) end state, even though electric power or service water was not restored. The peer review team felt that additional MAAP analyses should be performed to investigate the impact of varying MAAP input parameters on the resultant time to core uncovery, and extend the run time to show stable plant conditions.

Resolution: Additional MAAP uncertainty cases for BVPS-2 were performed using pessimistically biased values along with setting input parameters to their high or low limits. These cases were run out to 48-hours or until core damage occurred. The success state for the BV2REV3B PRA model was redefined as any case (including uncertainties) that did not go to core damage before 48-hours. For cases that went to core damage before 48-hours but after 20-hours, additional electric power recovery values were used, based on NUREG/CR-5496. For cases that lead to core uncovery before 20-hours, a plant specific electric power recovery model was used. If electric power recovery was successful for these cases, the sequence was also binned to the success end state.

F&O 2
Summary: This observation was identified in the Thermal Hydraulic Analysis Sub-element regarding room heatup calculations. This observation found that the loss of ventilation room heatup analysis for the Safeguards Building, which houses Auxiliary Feedwater, Low Head Safety Injection, and Quench Spray pumps, used heat loads based on non-DBA conditions with only the AFW pump operating. This resulted in a room heatup that was well below the Equipment Qualification (EQ) temperature limits, and therefore, the ventilation dependency for these pumps was not modeled in the BV2REV3A PRA. The peer review team recommended that the room heatup calculation be re-evaluated using the appropriate DBA heat loads, and determine the impact on the effected components.

Resolution: A new room heatup analysis was performed for the Safeguards Building using realistic time-dependent DBA heat loads, based on MAAP generated success criteria. The results of this analysis were reviewed and compared to the EQ temperature limits to see if the necessary components to mitigate core damage or containment failures would be functional at the time that they were required to function (up to 24 hours). It was concluded that all PRA modeled equipment located within the Safeguards Building would be available to perform its PRA function during a loss of all ventilation for up to 24 hours. Therefore, it was determined that the Safeguards Building ventilation system is not required for support of the PRA modeled equipment located within the area, and the BV2REV3A PRA modeling assumptions regarding this remain valid. The BV2REV3B PRA model was not changed as a result of this observation.

F&O 3
Summary: This observation was identified in the Data Analysis, Failure Probability Sub-element. It was observed that the number of demands for several components seemed very high, and that the BVPS-2 plant specific Bayesian updating of independent failure data for these components resulted in more optimistic failure rates than most other Westinghouse plants. The peer review team recommended that the component demands be verified.

Resolution: As a resolution to this PRA Peer Review observation, the success data (demands and hours of operation) for all Unit 2 components that used Bayesian updating of their failure rates were checked against the Maintenance Rule estimated success data, and were revised as needed if discrepancies were found. Additionally, all RISKMAN failure data distributions that were Bayesian updated in the BV2REV3A PRA model were revised in the BV2REV3B PRA model using the results of review for estimated demands and hours of operation. All Top Events were requantified in the BV2REV3B PRA model using these revised component failure rates, which were then used to requantify the CDF and LERF.

F&O 4
Summary: This observation was identified in the Human Reliability Analysis (HRA), Post-Initiator Human Actions Sub-element. It was observed that the BVPS human error

rates were developed using the Success Likelihood Index Methodology (SLIM) based on calibration curves from other plant HRAs from the mid-1980's. The peer review team recommended that these calibration curves be updated with current operator performance in the nuclear power industry.

Resolution: As a resolution to this PRA Peer Review observation all operator actions having a Risk Achievement Worth (RAW) greater than 2 (generally accepted as the risk significant threshold) were compared to similar actions for all Westinghouse plants by using the WOG/B&WOG PRA Comparison Database (Revisions 2 and 3). Additionally, a smaller subset of these plants was also looked at. These consisted of; Westinghouse 3-loop plants (since these were assumed to have similar operation action completion times based on plant power to heatup volume ratios), plants that also used the SLIM process, and Indian Point 2, which received a superior finding in their Human Reliability Analysis peer review. The results of this comparison show that the human error rates used in the BV2REV3A PRA model are all within the range of both comparison groups defined above, except for human action OPRCD3 (operator fails to cooldown and depressurize during a SGTR). However, the BV2REV3A value is of the same order of magnitude as most of the other plants reviewed and is not considered to be an outliner. It is therefore believed that the basic error curves used in the calibration of the BV2REV3A HRA are not grossly out of date, and that the current human error rates used in the PRA model are acceptable as is. Moreover, as a final resolution to this observation, future updates of the BVPS PRA models will use the EPRI HRA Calculator, which uses a more current and robust methodology. The BV2REV3B PRA model was not changed as a result of this observation.

F&O 5
Summary: This observation was identified in the Human-Reliability Analysis, Dependence Among Actions Sub-element. It was observed that the BVPS HRA did not have a documented process to perform a systematic search for dependent human actions credited on individual sequences and a method to adjust dependencies between multiple human error rates in the same sequence. The peer review team recommended that a robust technique be developed, documented, and used for the identification and quantification of dependent human error rates (HERs).

Resolution: In the initial development of the IPE HRA, an effort was made to eliminate the dependency between human actions by adjusting the split fraction value of the second dependent action, given that the first action failed. For example, if the operators failed to manually reestablish Main Feedwater following the failure of Auxiliary Feedwater, the human error rate for implementing Bleed and Feed cooling later in the accident progression was adjusted upwards. If the dependent actions were required to take place in the same period of time during the accident progression, the second dependent action was assigned to be a guaranteed failure. For example, if the operators failed to cooldown and depressurize the RCS by using the secondary coolant system, no credit was given to the operators to depressurize the RCS using the Pressurizer PORVs. However, as a resolution to this PRA Peer Review observation a method was established to verify that all dependent operator actions were captured by reviewing sequences with two or more failed split fractions that have a contribution from human actions. Of the sequences reviewed, the human actions were either previously adjusted during the IPE HRA, or were determined to be independent between split fractions. This independence was based on the actions not being conducted by the same set of operators (e.g., control room Reactor Operator action vs. local Auxiliary Plant Operator action), or different procedures being used separated by sufficient time in the accident progression (e.g., actions to makeup to the RWST given SI recirculation failures, following operator actions to align a spare Service Water pump earlier in the accident sequence progression). Human actions that are modeled in a single top event have appropriate dependencies modeled in the fault trees. Moreover, as a final resolution to this observation, future updates of the BVPS PRA models will use the EPRI HRA Calculator, which uses a more current and robust methodology. The BV2REV3B PRA model was not changed as a result of this observation.

3.4 LEVEL 3 PRA MODEL

The BVPS-1/2 Level 3 PRA model determines off-site dose and economic impacts of severe accidents based on the Level 1 PRA results, the Level 2 PRA results, atmospheric transport, mitigating actions, dose accumulation, early and latent health effects, and economic analyses.

The MELCOR Accident Consequence Code System (MACCS2) Version 1.13.1 was used to perform the calculations of the off-site consequences of a severe accident. This code is documented in NUREG/CR-6613 (Reference 28), "Code Manual for MACCS2: Volumes 1 and 2."

Plant-specific release data included the time-dependent nuclide distribution of releases and release frequencies. The behavior of the population during a release (evacuation parameters) was based on plant and site-specific set points. These data were used in combination with site-specific meteorology to simulate the probability distribution of impact risks (both exposures and economic effects) to the surrounding 50-mile radius population as a result of the release accident sequences at Beaver Valley.

The following sections describe input data for the MACCS2 (Reference 28) analysis tool. The analyses are found in References 32-35.

3.4.1 Population Distribution

The population surrounding the Beaver Valley Power Station site, up to a 50 mile radius, was estimated based on the most recent United States Census Bureau decennial census data. Details are provided in "Calculation Package for Population Projections – Beaver Valley Power Station" (Reference 29). The population distribution was estimated in 9 concentric bands at 0 to 1 mile, 1 to 2 miles, 2 to 5 miles, 5 to 10 miles, 10 to 15 miles, 15 to 20 miles, 20 to 30 miles, 30 to 40 miles, and 40 to 50 miles, and 16 directional sectors with each direction consisting of 22.5 degrees. The population was projected to the year 2047 by calculating an annual growth rate for each county in the 50 mile radius derived from state and national population projections. Geometric growth rates were calculated for each county in Ohio and Pennsylvania based on 2030 county projections. However, if the county population had decreased from 2000 to 2030, it was assumed there was no growth through 2030 (i.e., the 2030 population was equal to the 2000 population), and the national growth rate was applied from 2030 to 2047 to obtain an overall multiplier fore the 2047 projection. For West Virginia, projections were available through 2050. The annual growth rate was applied to obtain a 2047 multiplier, unless a negative growth rate existed, in which case no growth was assumed. The population distribution used in this analysis is provided in the following table.

Table 3.4.1-1 Population Projections Used in SAMA Analysis

From Radius	To Radius	Direction	Code	2000 Population	2047 Population
0	1	N	1	0	0
0	1	NNE	2	0	0
0	1	NE	3	93	110
0	1	ENE	4	38	45
0	1	E	5	88	104
0	1	ESE	6	0	0
0	1	SE	7	7	8
0	1	SSE	8	0	0
0	1	S	9	0	0
0	1	SSW	10	0	0
0	1	SW	11	2	2
0	1	WSW	12	0	0
0	1	W	13	0	0
0	1	WNW	14	0	0
0	1	NW	15	132	156
0	1	NNW	16	53	63
1	2	N	17	197	232
1	2	NNE	18	62	73
1	2	NE	19	4	5
1	2	ENE	20	7	8
1	2	E	21	74	87
1	2	ESE	22	64	76
1	2	SE	23	116	137
1	2	SSE	24	22	26
1	2	S	25	18	21
1	2	SSW	26	35	41
1	2	SW	27	25	30
1	2	WSW	28	73	86
1	2	W	29	141	166
1	2	WNW	30	0	0
1	2	NW	31	1,651	1,948
1	2	NNW	32	470	555
2	5	N	33	835	985
2	5	NNE	34	1,016	1,199
2	5	NE	35	1,130	1,333
2	5	ENE	36	683	806
2	5	E	37	1,039	1,226
2	5	ESE	38	713	841
2	5	SE	39	284	335
2	5	SSE	40	637	752
2	5	S	41	486	573
2	5	SSW	42	742	876
2	5	SW	43	619	730
2	5	WSW	44	217	256
2	5	W	45	723	853
2	5	WNW	46	802	946
2	5	NW	47	1,753	2,069
2	5	NNW	48	573	676

Table 3.4.1-1 Population Projections Used in SAMA Analysis (Cont.)

From Radius	To Radius	Direction	Code	2000 Population	2047 Population
5	10	N	49	2,317	2,734
5	10	NNE	50	3,875	4,573
5	10	NE	51	18,262	21,549
5	10	ENE	52	14,995	17,694
5	10	E	53	19,461	22,964
5	10	ESE	54	7,307	8,606
5	10	SE	55	1,589	1,840
5	10	SSE	56	1,777	2,090
5	10	S	57	4,734	5,586
5	10	SSW	58	1,284	1,512
5	10	SW	59	3,604	3,875
5	10	WSW	60	1,886	1,918
5	10	W	61	19,534	21,213
5	10	WNW	62	7,332	8,652
5	10	NW	63	2,156	2,544
5	10	NNW	64	1,283	1,514
10	15	N	65	4,297	5,070
10	15	NNE	66	20,102	23,720
10	15	NE	67	18,866	22,262
10	15	ENE	68	13,403	15,810
10	15	E	69	18,133	20,507
10	15	ESE	70	31,028	31,750
10	15	SE	71	5,136	5,187
10	15	SSE	72	1,105	1,132
10	15	S	73	1,064	1,099
10	15	SSW	74	5,120	5,285
10	15	SW	75	9,357	9,802
10	15	WSW	76	1,931	2,095
10	15	W	77	6,926	7,980
10	15	WNW	78	3,491	4,119
10	15	NW	79	2,716	3,205
10	15	NNW	80	1,975	2,331
15	20	N	81	2,679	3,161
15	20	NNE	82	19,651	23,188
15	20	NE	83	8,256	10,097
15	20	ENE	84	26,225	35,104
15	20	E	85	20,890	21,130
15	20	ESE	86	32,047	32,367
15	20	SE	87	20,102	20,303
15	20	SSE	88	5,210	5,342
15	20	S	89	5,479	5,643
15	20	SSW	90	23,299	23,522
15	20	SW	91	6,325	7,364
15	20	WSW	92	1,568	1,850
15	20	W	93	1,535	1,811
15	20	WNW	94	3,151	3,718
15	20	NW	95	5,793	6,836
15	20	NNW	96	9,801	11,565
20	30	N	97	40,448	47,729

Table 3.4.1-1 Population Projections Used in SAMA Analysis (Cont.)

From Radius	To Radius	Direction	Code	2000 Population	2047 Population
20	30	NNE	98	25,927	31,193
20	30	NE	99	11,544	15,668
20	30	ENE	100	26,859	36,797
20	30	E	101	73,055	77,064
20	30	ESE	102	410,196	414,298
20	30	SE	103	227,938	230,716
20	30	SSE	104	39,083	40,229
20	30	S	105	5,494	5,656
20	30	SSW	106	38,710	41,558
20	30	SW	107	20,523	24,217
20	30	WSW	108	5,090	6,155
20	30	W	109	4,182	5,480
20	30	WNW	110	10,727	12,776
20	30	NW	111	33,243	39,227
20	30	NNW	112	38,242	45,126
30	40	N	113	27,393	32,324
30	40	NNE	114	14,394	17,649
30	40	NE	115	20,468	28,041
30	40	ENE	116	52,734	72,065
30	40	E	117	88,641	97,229
30	40	ESE	118	343,130	347,829
30	40	SE	119	114,676	116,792
30	40	SSE	120	49,039	50,510
30	40	S	121	10,274	10,553
30	40	SSW	122	35,720	38,675
30	40	SW	123	10,554	12,454
30	40	WSW	124	6,314	8,164
30	40	W	125	15,333	21,441
30	40	WNW	126	25,741	30,543
30	40	NW	127	19,379	22,864
30	40	NNW	128	218,945	258,355
40	50	N	129	67,035	79,101
40	50	NNE	130	26,361	31,533
40	50	NE	131	9,705	13,035
40	50	ENE	132	31,197	37,772
40	50	E	133	43,404	48,911
40	50	ESE	134	115,071	120,818
40	50	SE	135	79,774	83,809
40	50	SSE	136	21,216	21,842
40	50	S	137	5,221	5,321
40	50	SSW	138	72,617	79,681
40	50	SW	139	12,337	14,558
40	50	WSW	140	9,276	11,210
40	50	W	141	19,628	24,920
40	50	WNW	142	83,296	97,999
40	50	NW	143	26,594	30,210
40	50	NNW	144	123,093	145,250
			Total	**3,273,502**	**3,607,001**

3.4.2 Economic Data

The Environmental Protection Agency's computer program SECPOP was the basis for the economic data used in the offsite evaluations done in this analysis. This code utilized county economic factors derived from the 2000 census and various other government sources dated 1997 to 1999. For the preparation of data for the Beaver Valley model, the county data file was updated to circa 2002 for the 23 counties within 50 miles of the plant. Reference 33 provides the input data used in this analysis:

Variable	Description	BV1/2 Value
DPRATE(1)	Property depreciation rate (per yr)	0.20
DSRATE(1)	Investment rate of return (per yr)	0.12
EVACST(2)	Daily cost for a person who has been evacuated ($/person-day)	$49
POPCST(2)	Population relocation cost ($/person)	$13,727
RELCST(2)	Daily cost for a person who is relocated ($/person-day)	$49
CDFRM(2)	Cost of farm decontamination for various levels of decontamination ($/hectare)	$1,169 & $2,598
CDNFRM(2)	Cost of non-farm decontamination per resident person for various levels of decontamination ($/person)	$6,236 & $16,630
DLBCST(2)	Average cost of decontamination labor ($/man-year)	$72,756
VALWF(2)	Value of farm wealth ($/hectare)	$6,957
VALWNF(2)	Value of non-farm wealth average in US ($/person)	$181,881

(1) DPRATE and DSRATE are based on MACCS2 Users Manual (Reference 28)

(2) Calc 17676-0002 "Beaver Valley Power Station - MACCS2 Input Data".

3.4.3 Nuclide Release

The equilibrium core inventory was assumed at the end of a fuel cycle with fuel from three different fuel cycles in equal proportions. It was originally developed using ORIGEN-S as described in the BVPS Containment Conversion Licensing Report (Reference 31).

The following table provides the inventory of the core at shutdown used in this analysis. This information is from Reference 30, Section 5.2.3.3

Table 3.4.3-1 Core Inventory

Nuclide	Core Inventory (Curies)
Ag-111	5.05E+6
Ag-112	2.28E+6
Am-241	1.17E+4
Am-242	7.04E+6
Am-244	1.89E+7
Ba-137m	9.35E+6
Ba-139	1.41E+8
Ba-140	1.42E+8
Br-82	3.02E+5
Br-83	9.37E+6
Ce-141	1.30E+8
Ce-143	1.21E+8
Ce-144	9.82E+7
Cm-242	2.42E+6
Cm-244	5.97E+5
Cs-134	1.57E+7
Cs-134m	3.69E+6
Cs-135m	4.39E+6
Cs-136	4.97E+6
Cs-137	9.81E+6
Cs-138	1.48E+8
Eu-156	2.29E+7
Eu-157	2.41E+6
H-3	4.36E+4
I-129	2.86E+0
I-130	2.07E+6
I-131	7.78E+7
I-132	1.14E+8
I-133	1.60E+8
I-134	1.77E+8
I-135	1.52E+8
Kr-83m	9.46E+6
Kr-85	8.27E+5
Kr-85m	1.95E+7
Kr-87	3.91E+7
Kr-88	5.43E+7
La-140	1.46E+8
La-141	1.29E+8
La-142	1.26E+8
La-143	1.20E+8

Table 3.4.3-1 Core Inventory (Cont.)

Nuclide	Core Inventory (Curies)
Mo-101	1.33E+8
Mo-99	1.45E+8
Nb-95	1.34E+8
Nb-95m	1.52E+6
Nb-97	1.27E+8
Nb-97m	1.19E+8
Nd-147	5.22E+7
Nd-149	3.02E+7
Nd-151	1.58E+7
Np-238	3.98E+7
Np-239	1.66E+9
Np-240	4.32E+6
Pd-109	3.26E+7
Pm-147	1.38E+7
Pm-148	1.41E+7
Pm-148m	2.37E+6
Pm-149	4.82E+7
Pm-151	1.60E+7
Pr-142	5.57E+6
Pr-143	1.18E+8
Pr-144	9.89E+7
Pr-144m	1.38E+6
Pr-147	5.18E+7
Pu-238	3.40E+5
Pu-239	2.86E+4
Pu-240	3.87E+4
Pu-241	1.13E+7
Pu-242	2.01E+2
Pu-243	4.23E+7
Rb-86	1.69E+5
Rb-88	5.57E+7
Rb-89	7.26E+7
Rh-103m	1.26E+8
Rh-105	8.16E+7
Rh-106	5.13E+7
Ru-103	1.26E+8
Ru-105	8.90E+7
Ru-106	4.63E+7
Sb-127	6.92E+6
Sb-129	2.52E+7

Table 3.4.3-1 Core Inventory (Cont.)

Nuclide	Core Inventory (Curies)
Sb-130	8.37E+6
Sb-131	6.09E+7
Se-83	4.42E+6
Sm-153	4.02E+7
Sm-155	3.11E+6
Sm-156	1.93E+6
Sn-127	2.78E+6
Sr-89	7.61E+7
Sr-90	7.21E+6
Sr-91	9.50E+7
Sr-92	1.01E+8
Tc-101	1.33E+8
Tc-104	1.05E+8
Tc-99m	1.29E+8
Te-127	6.81E+6
Te-127m	1.13E+6
Te-129	2.40E+7
Te-129m	4.87E+6
Te-131	6.54E+7
Te-131m	1.57E+7
Te-132	1.12E+8
Te-133	8.66E+7
Te-133m	7.12E+7
Te-134	1.41E+8
U-239	1.66E+9
Xe-131m	1.08E+6
Xe-133	1.60E+8
Xe-133m	5.05E+6
Xe-135	4.84E+7
Xe-135m	3.36E+7
Xe-138	1.36E+8
Y-90	7.49E+6
Y-91	9.87E+7
Y-91m	5.51E+7
Y-92	1.02E+8
Y-93	7.73E+7
Y-94	1.23E+8

Table 3.4.3-1 Core Inventory (Cont.)

Nuclide	Core Inventory (Curies)
Y-95	1.28E+8
Zr-95	1.33E+8
Zr-97	1.26E+8

Table 3.4.3-2 provides a description of the release characteristics evaluated in this analysis.

Table 3.4.3-2 Release Descriptions

Release Category	Representative Bins	MACCS2 Run Code	Plume Number	Energy Level (cal/sec)	Energy Level (W)	Release Height (m)	Time of Release (hr)	Duration (hr)	Alarm Delay (hr)
Variable			**NUMREL**		**PLHEAT**	**PLHITE**	**PDELAY**	**PLUDUR**	**OALARM**
INTACT	BV21	A	1	454	1.90E+03	43.7	4	4	4
INTACT	BV21	A	2	262.84	1.10E+03	43.7	8	20	4
VSEQ-ECF	BV19	B	1	3.75E+07	1.57E+08	3.2	2	0.5	1
SGTR-ECF	BV18	C	1	8.48E+07	3.55E+08	26.82	8	0.5	1
DCH-ECF	BV1, BV3	D	1	6.59E+07	2.76E+08	43.7	3	4	1
VSEQ-SECF	BV20	E	1	1.00E+06	4.19E+06	3.2	3	1	1
LOCI-SECF	BV7	F	1	2.15E+06	9.00E+06	12	1.5	0.5	1
LOCI-SECF	BV7	F	2	1.12E+06	4.69E+06	12	2	9.5	1
BV5-SECF	BV5	K	1	2.15E+06	9.00E+06	43.7	1.5	0.5	1
BV5-SECF	BV5	K	2	1.12E+06	4.69E+06	43.7	2	9.5	1
Large-Late	BV10, BV12	G	1	6.59E+07	2.76E+08	43.7	10	0.5	4
Large-Late	BV10, BV12	G	2	1.27E+07	5.32E+07	43.7	10.5	3	4
Small-Late	BV13, BV15	H	1	1.31E+07	5.49E+07	43.7	25	0.5	4
Small-Late	BV13, BV15	H	2	2.63E+06	1.10E+07	43.7	25.5	9.5	4
H2 Burn-Late	BV9	I	1	6.59E+07	2.76E+08	43.7	10	0.5	4
H2 Burn-Late	BV9	I	2	1.27E+07	5.32E+07	43.7	10.5	3.5	4
BMMT-Late	BV17	J	1	6.59E+07	2.76E+08	0	24	1	4

3.4.4 Emergency Response

A reactor scram signal begins each evaluated accident sequence. A General Emergency is declared when plant conditions degrade to the point where it is judged that there is a credible risk to the public. Therefore, the timing of the General Emergency declaration is sequence specific and alarms range from 1 to 4 hours for the release sequences evaluated.

The MACCS2 User's Guide input parameters of 95 percent of the population within 10 miles of the plant [Emergency Planning Zone (EPZ)] evacuating and 5 percent not evacuating were employed. These values have been used in similar studies (e.g., Hatch, Calvert Cliffs, (SNOC 2000) and (BGE 1998)) and are conservative relative to the NUREG-1150 study, which assumed evacuation of 99.5 percent of the population within the EPZ.

The evacuation speed was calculated by comparing the travel time estimates to the travel distances required. The Aliquippa/Hopewell area has the greatest population density in the EPZ, requires the longest evacuation time, and is only a few miles from the edge of the EPZ. It follows that the slowest and most conservative evacuation speeds would occur in this area. Based on the published evacuation routes and the population distribution in the area, a typical travel distance to the edge of the EPZ from this area is approximately 3 miles. Using the worst case evacuation time (inclement weather and persons without transportation) of 6¼ hours an average evacuation speed of 0.2 m/s was determined.

Three evacuation sensitivity cases were also performed to determine the impact of evacuation assumptions. One sensitivity case reduced the evacuation speed by a factor of four (0.05 m/sec) and the second increased the speed to 2.24 m/s (5 mph). The third sensitivity case assumed an increase by a factor of 1.5 in the alarm time, thus delaying the commencement of physical evacuation. The results are discussed in Section 8.

3.4.5 Meteorological Data

Each year of meteorological data consists of 8,760 weather data sets of hourly recordings of wind direction, wind speed, atmospheric stability, and accumulated precipitation. The data were from the Beaver Valley Power Station site weather facility for the years 2001, 2002, 2003, 2004, and 2005. MACCS2 does not permit missing data, so bad or missing data were filled in with National Oceanic and Atmospheric Administration (NOAA) data from the Pittsburgh International Airport (nearest most complete source of data) obtained from the NOAA Internet website. The approach used in this analysis was to perform MACCS2 analyses for each of the years for which meteorological data was gathered and combine the results after the MACCS2 analyses rather than before. Due to the consideration of five years of weather data, it is assumed that the average result from the analysis would be considered typical and representative. No one year was found to be conservative with respect to all release sequences.

3.5 SEVERE ACCIDENT RISK RESULTS

Using the MACCS2 code, the dose and economic costs associated with a severe accident at Beaver Valley was calculated for each of the years for which meteorological data was gathered. This information is provided below in Table 3.5-1 and Table 3.5-2, respectively. The average value of the yearly result for each release category was used in remainder of the analysis to represent the dose and cost for each of the specific release categories.

Table 3.5-1 Total L-EFFECTIVE LIFE Dose in Sieverts

Release Category	MACCS2 Run Code	BVPS Composite Weather Sensitivity Results					
		2001	2002	2003	2004	2005	Average
INTACT	A	8	7	8	7	7	8
ECF							
VSEQ	B	50,400	47,200	51,000	53,600	40,800	48,600
SGTR	C	44,500	41,400	43,800	46,500	37,000	42,640
DCH	D	86,800	84,800	86,600	76,400	77,600	82,440
SECF							
VSEQ	E	50,500	48,000	47,800	46,900	44,800	47,600
LOCI	F	35,200	35,500	33,200	34,000	36,400	34,860
BV5	K	43,800	39,800	41,300	41,000	42,700	41,720
LATE							
Large	G	1,530	1,440	1,780	1,600	1,450	1,560
Small	H	20,200	19,200	18,800	18,600	20,500	19,460
H2 Burn	I	19,300	17,200	17,600	16,300	17,900	17,660
BMMT	J	7,680	7,250	7,200	7,990	6,990	7,422

Table 3.5-2 Total Economic Costs in Dollars

Release Category	MACCS2 Run Code	BVPS Composite Weather Sensitivity Results					
		2001	2002	2003	2004	2005	Average
INTACT	A	6.400E+03	5.600E+03	5.590E+03	1.000E+04	7.510E+03	7.020E+03
ECF							
VSEQ	B	3.530E+10	3.260E+10	3.100E+10	3.350E+10	3.390E+10	3.326E+10
SGTR	C	4.280E+10	3.790E+10	3.580E+10	4.080E+10	3.840E+10	3.914E+10
DCH	D	4.800E+10	5.010E+10	5.010E+10	4.400E+10	5.000E+10	4.844E+10
SECF							
SGTR	E	2.540E+10	2.560E+10	2.690E+10	2.440E+10	2.920E+10	2.630E+10
LOCI	F	2.650E+10	2.520E+10	2.570E+10	2.460E+10	2.840E+10	2.608E+10
BV5	K	1.130E+10	1.070E+10	1.190E+10	1.050E+10	1.240E+10	1.136E+10
LATE							
Large	G	1.180E+08	1.260E+08	1.430E+08	1.590E+08	1.310E+08	1.354E+08
Small	H	1.090E+10	1.010E+10	1.150E+10	1.040E+10	1.170E+10	1.092E+10
H2 Burn	I	6.670E+09	6.220E+09	6.460E+09	5.600E+09	5.900E+09	6.170E+09
BMMT	J	4.380E+09	4.360E+09	5.480E+09	4.450E+09	4.700E+09	4.674E+09

3.6 MAJOR PRA MODELING DIFFERENCES BETWEEN BVPS UNIT 1 AND UNIT 2

Listed below are some major design differences between the BVPS Units that are accounted for in the PRA models. In addition, key differences in the BVPS PRA models were also previously docketed in Attachment B of the following letter.

- Pearce/USNRC, Beaver Valley Power Station, Unit No. 1 and No. 2, BV-1 Docket No. 50-334, License No. DPR-66 and BV-2 Docket No. 50-412, License No. NPF-73, Response to a Request for Additional Information in Support of License Amendment Requests Nos. 306 and 176, dated October 29, 2004, Serial L-04-141.

1. Unit 1 has an additional feedwater pump (Dedicated AFW Pump) powered off the ERF diesel generator, which can be used during an SBO. This pump can provide secondary heat removal even if the SG are water solid, so it is not dependant on battery life. Unit 2 only has the Turbine-Driven AFW Pump, which fail if the SG goes water solid, so it is dependent on battery life during SBO conditions. Plant specific SBO MAAP analyses show that with the DAFW pump, as long as the RCP seal LOCA is initially less than 182 gpm and operators cooldown and depressurize the RCS, Unit 1 will not melt or uncover the core during a 48 hour period following the SBO. At Unit 2, this is not the case, and the core will uncover and melt during a 48 hour period following the SBO.

2. The Unit 1 Emergency DC Battery Rooms are constructed with concrete block walls, which have limited seismic capacity. At Unit 2 the Emergency DC Battery Rooms are constructed with reinforced concrete walls that have significant seismic capacity.

3. At Unit 1 the steam generators were replaced during 1RO17 and therefore have about half of the SGTR initiating event frequency of the Unit 2 value (2.09E-03 vs. 4.82E-03).

4. The Unit 2 RWST volume is about twice the size of the Unit 1 volume (~ 860,000 gal vs. ~440,000 gal).

5. At Unit 1 the atmospheric steam dump valves have a higher capacity than Unit 2 (294,400 lbs/hr vs. 235,000 lbs/hr) and therefore the RCS cooldown and depressurization using the secondary heat removal system success criteria is different. Unit 1 only requires 1 ASDV and feedwater to the associated SG, while Unit 2 requires 2 ASDVs with feedwater to both associated SGs.

6. Unit 2 normally has two Service Water pumps in service, while Unit 1 normally only has one River Water pump in service. Therefore, since the success criteria for both Units is one River Water/Service Water pump, there is a lower system failure probability at Unit 2 due to not having to start a standby pump given the failure of a running pump.

4 COST OF SEVERE ACCIDENT RISK / MAXIMUM BENEFIT

Cost/benefit evaluation of SAMAs is based upon the cost of implementation of a SAMA compared to the averted onsite and offsite costs resulting from the implementation of that SAMA. The methodology used for this evaluation was based upon the NRC's guidance for the performance of cost-benefit analyses (Reference 20). This guidance involves determining the net value for each SAMA according to the following formula:

Net Value = (APE + AOC + AOE + AOSC) – COE

where APE = present value of averted public exposure ($),
AOC = present value of averted offsite property damage costs ($),
AOE = present value of averted occupational exposure ($),
AOSC = present value of averted onsite costs ($)
COE = cost of enhancement ($).

If the net value of a SAMA is negative, the cost of implementing the SAMA is larger than the benefit associated with the SAMA and is not considered beneficial. The derivation of each of these costs is described in below.

The following specific values were used for various terms in the analyses:

Present Worth

The present worth was determined by:

$$PW = \frac{1 - e^{-rt}}{r}$$

Where:

r is the **discount rate = 7%** (assumed throughout these analyses)
t is the **duration of the license renewal = 20 years**
PW is the present worth of a string of annual payments = **10.76**

Dollars per REM

The conversion factor used for assigning a monetary value to on-site and off-site exposures was **$2,000/person-rem averted**. This is consistent with the NRC's regulatory analysis guidelines presented in and used throughout NUREG/BR-0184, Reference 20.

On-site Person REM per Accident

The occupational exposure associated with severe accidents was assumed to be **23,300 person-rem/accident.** This value includes a short-term component of 3,300 person-rem/accident and a long-term component of 20,000 person-rem/accident. These estimates are consistent with the "best estimate" values presented in Section 5.7.3 of Reference 20. In the cost/benefit analyses, the accident-related on-site exposures were calculated using the best estimate exposure components applied over the on-site cleanup period.

On-site Cleanup Period

In the cost/benefit analyses, the accident-related on-site exposures were calculated over a **10-year cleanup period**.

Present Worth On-site Cleanup Cost per Accident

The estimated cleanup cost for severe accidents was assumed to be **$1.5E+09/accident** (undiscounted). This value was derived by the NRC in Reference 20, Section 5.7.6.1, Cleanup and Decontamination. This cost is the sum of equal annual costs over a 10-year cleanup period. At a 7% discount rate, the present value of this stream of costs is **$1.1E+09**.

4.1 OFF-SITE EXPOSURE COST

Accident-Related Off-Site Dose Costs

Offsite doses were determined using the consolidated MACCS2 model developed for BVPS Units 1 and 2. Costs associated with these doses were calculated using the following equation:

$$APE = \left(F_S D_{P_S} - F_A D_{P_A}\right) R \frac{1 - e^{-rt_f}}{r} \qquad (1)$$

where:

APE = monetary value of accident risk avoided due to population doses, after discounting

R = monetary equivalent of unit dose, ($/person-rem)

F = accident frequency (events/yr)
D_P = population dose factor (person-rems/event)
S = status quo (current conditions)
A = after implementation of proposed action
r = real discount rate
t_f = analysis period (years).

Using the values for r, t_f, and R given above:

$$W_P = (\$2.15E + 4)\left(F_S D_{P_S} - F_A D_{P_A}\right)$$

4.2 OFF-SITE ECONOMIC COST

Accident-Related Off-Site Property Damage Costs

Offsite damage was determined using the MACCS2 model developed for BVPS-2. Costs associated with these damages were calculated using the following equation:

$$AOC = \left(F_S P_{D_S} - F_A P_{D_A}\right)\frac{1 - e^{-rt_f}}{r}$$

where:

AOC = monetary value of accident risk avoided due to offsite property damage, after discounting
F = accident frequency (events/yr)
P_D = offsite property loss factor (dollars/event)
r = real discount rate
t_f = analysis period (years).

4.3 ON-SITE EXPOSURE COST

Methods for Calculating Averted Costs Associated with Onsite Accident Dose Costs

a) **Immediate Doses** (at time of accident and for immediate management of emergency)

For the case where the plant is in operation, the equations in Reference 20 can be expressed as:

$$W_{IO} = \left(F_S D_{IO_S} - F_A D_{IO_A}\right) R \frac{1 - e^{-rt_f}}{r} \quad (1)$$

where:
W_{IO} = monetary value of accident risk avoided due to immediate doses, after discounting
R = monetary equivalent of unit dose, ($/person-rem)
F = accident frequency (events/yr)
D_{IO} = immediate occupational dose (person-rems/event)
S = status quo (current conditions)
A = after implementation of proposed action
r = real discount rate
t_f = analysis period (years).

The values used are:
R = $2000/person rem
r = .07
D_{IO} = 3,300 person-rems /accident (best estimate)

The license extension time of 20 years is used for t_f.

For the basis discount rate, assuming F_A is zero, the best estimate of the limiting savings is

$$\begin{aligned} W_{IO} &= \left(F_S D_{IO_S}\right) R \frac{1-e^{-rt_f}}{r} \\ &= 3300 * F * \$2000 * \frac{1-e^{-.07*20}}{.07} \\ &= F * \$6{,}600{,}000 * 10.763 \\ &= F * \$0.71E + 8 \text{ , (\$).} \end{aligned}$$

b) **Long-Term Doses** (process of cleanup and refurbishment or decontamination)

For the case where the plant is in operation, the equations in Reference 20 can be expressed as:

$$W_{LTO} = \left(F_S D_{LTO_S} - F_A D_{LTO_A}\right) R * \frac{1-e^{-rt_f}}{r} * \frac{1-e^{-rm}}{rm} \qquad (2)$$

where:

W_{IO} = monetary value of accident risk avoided long term doses, after discounting, \$

m = years over which long-term doses accrue.

The values used are:

R = \$2000/person rem
r = .07
D_{LTO} = 20,000 person-rem /accident (best estimate)
m = “as long as 10 years”

The license extension period of 20 years is used for t_f.

For the discount rate of 7%, assuming F_A is zero, the best estimate of the limiting savings is

$$\begin{aligned} W_{LTO} &= \left(F_S D_{LTO_S}\right) R * \frac{1-e^{-rt_f}}{r} * \frac{1-e^{-rm}}{rm} \\ &= \left(F_S 20000\right) \$2000 * \frac{1-e^{-.07*20}}{.07} * \frac{1-e^{-.07*10}}{.07*10} \\ &= F_S * \$40{,}000{,}000 * 10.763 * 0.719 \\ &= F_S * \$3.10E + 8 \text{ , (\$).} \end{aligned}$$

c) **<u>Total Accident-Related Occupational (On-site) Exposures</u>**

Combining equations (1) and (2) above, using delta (Δ) to signify the difference in accident frequency resulting from the proposed actions, and using the above numerical values, the long term accident related on-site (occupational) exposure avoided (AOE) is:

<u>Best Estimate</u>:

$$AOE = W_{IO} + W_{LTO} = F * \$(0.71 + 3.1)E + 8 = F * \$3.81E + 8 \ (\$)$$

4.4 ON-SITE ECONOMIC COST

<u>Methods for Calculation of Averted Costs Associated with Accident-Related On-Site Property Damage</u>

a) **<u>Cleanup/Decontamination</u>**

Reference 20 assumes a total cleanup/decontamination cost of $1.5E+9 as a reasonable estimate and this same value was adopted for these analyses. Considering a 10-year cleanup period, the present value of this cost is:

$$PV_{CD} = \left(\frac{C_{CD}}{m}\right)\left(\frac{1 - e^{-rm}}{r}\right)$$

Where

PV_{CD} = Present value of the cost of cleanup/decontamination.
C_{CD} = Total cost of the cleanup/decontamination effort.
m = Cleanup period.
r = Discount rate.

Based upon the values previously assumed:

$$PV_{CD} = \left(\frac{\$1.5E + 9}{10}\right)\left(\frac{1 - e^{-.07*10}}{.07}\right)$$

$$PV_{CD} = \$1.079E + 9$$

This cost is integrated over the term of the proposed license extension as follows

$$U_{CD} = PV_{CD}\,\frac{1 - e^{-rt_f}}{r}$$

Based upon the values previously assumed:

$$U_{CD} = \$1.079E + 9\ [10.763]$$
$$U_{CD} = \$1.161E + 10$$

b) **Replacement Power Costs**

Replacement power costs, U_{RP}, are an additional contributor to onsite costs. These are calculated in accordance with NUREG/BR-0184, Section 5.6.7.2.[1] Since replacement power will be needed for that time period following a severe accident, for the remainder of the expected generating plant life, long-term power replacement calculations have been used. The calculations are based on the 910 MWe reference plant, and are appropriately scaled for the 977 MWe BVPS-2. The present value of replacement power is calculated as follows:

$$PV_{RP} = \left(\frac{\left(\$1.2E + 8\right)\dfrac{(Ratepwr)}{(910MWe)}}{r} \right)\left(1 - e^{-rt_f}\right)^2$$

Where
- PV_{RP} = Present value of the cost of replacement power for a single event.
- t_f = analysis period (years).
- r = Discount rate.
- Ratepwr = Rated power of the unit

The \$1.2E+8 value has no intrinsic meaning but is a substitute for a string of non-constant replacement power costs that occur over the lifetime of a "generic" reactor after an event (from Reference 20). This equation was developed per NUREG/BR-0184 for discount rates between 5% and 10% only.

For discount rates between 1% and 5%, Reference 20 indicates that a linear interpolation is appropriate between present values of \$1.2E+9 at 5% and \$1.6E+9 at 1%. So for discount rates in this range the following equation was used to perform this linear interpolation.

$$PV_{RP} = \left\{ \left(\$1.6E + 9\right) - \left(\frac{\left[\left(\$1.6E + 9\right) - \left(\$1.2E + 9\right)\right]}{\left[5\% - 1\%\right]} * \left[r_s - 1\% \right] \right) \right\} * \left\{ \frac{Ratepwr}{910MWe} \right\}$$

Where
- r_s = Discount rate (small), between 1% and 5%.

[1] The section number for Section 5.6.7.2 apparently contains a typographical error. This section is a subsection of 5.7.6 and follows 5.7.6.1. However, the section number as it appears in the NUREG will be used in this document.

Ratepwr = Rated power of the unit

To account for the entire lifetime of the facility, U_{RP} was then calculated from PV_{RP}, as follows:

$$U_{RP} = \frac{PV_{RP}}{r}\left(1 - e^{-rt_f}\right)^2$$

Where
U_{RP} = Present value of the cost of replacement power over the life of the facility.

Again, this equation is only applicable in the range of discount rates from 5% to 10%. NUREG/BR-0184 states that for lower discount rates, linear interpolations for U_{RP} are recommended between \$1.9E+10 at 1% and \$1.2E+10 at 5%. The following equation was used to perform this linear interpolation:

$$U_{RP} = \left\{ \left(\$1.9E + 10\right) - \left(\frac{\left[\left(\$1.9E + 10\right) - \left(\$1.2E + 10\right)\right]}{\left[5\% - 1\%\right]} * \left[r_s - 1\% \right] \right) \right\} * \left\{ \frac{Ratepwr}{910MWe} \right\}$$

Where
r_s = Discount rate (small), between 1% and 5%.
Ratepwr = Rated power of the unit

c) **Repair and Refurbishment**

It is assumed that the plant would not be repaired/refurbished; therefore, there is not contribution to averted onsite costs from this source.

d) **Total Onsite Property Damage Costs**

The net present value of averted onsite damage costs is, therefore:

$$AOSC = F * \left(U_{CD} + U_{RP}\right)$$

Where F = Annual frequency of the event.

4.5 TOTAL COST OF SEVERE ACCIDENT RISK / MAXIMUM BENEFIT

Cost/benefit evaluation of the maximum benefit is baseline risk of the plant converted dollars by summing the contributors to cost.

Maximum Benefit Value = (APE + AOC + AOE + AOSC)

where APE = present value of averted public exposure ($),
AOC = present value of averted offsite property damage costs ($),
AOE = present value of averted occupational exposure ($),
AOSC = present value of averted onsite costs ($)

For Beaver Valley Unit 2, this value is $5,097,992 as shown below.

Parameter	Unit 2 Present Dollar Value ($)
Averted Public Exposure	$1,203,099
Averted offsite costs	$3,403,247
Averted occupational exposure	$9,146
Averted onsite costs	$482,500
Total	$5,097,992

5 SAMA IDENTIFICATION

A list of SAMA candidates was developed by reviewing the major contributors to CDF and population dose based on the plant-specific risk assessment and the standard PWR list of enhancements from Reference 24 (NEI 05-01). This section discusses the SAMA selection process and its results.

5.1 PRA IMPORTANCE

The top core damage sequences and the components/systems having the greatest potential for risk reduction were examined to determine whether additional SAMAs could be identified from these sources.

Use of Importance Measures
Risk reduction worth (RRW) of the components in the baseline model was used to identify those basic events that could have a significant potential for reducing risk. Components with risk reduction worth (RRW) >1.005 were identified as the most important components. A similar review was performed on a system basis. The components and systems were reviewed to ensure that each component and system is covered by an existing SAMA item or added to the list if not.

Use of the Top Sequences

The top sequences leading to core melt were reviewed. A key result is that no single PRA sequence makes up a large fraction of the core damage frequency. The sequences were reviewed to ensure that initiators and failures identified in the sequences were either covered by existing SAMAs or added to the list of plant specific SAMAs.

5.2 PLANT IPE

The Beaver Valley Unit 2 PRA identified some potential vulnerabilities. Corresponding enhancements have been considered.

As noted in the IPE, large fractions of the CDF are associated with RCP seal LOCA and station blackout. Other major contributors are containment bypass/isolation failure, loss of switchgear HVAC and transients without scram.

These accident categories are not always mutually exclusive. One of the top ranked sequences illustrates this clearly. A loss of offsite power will challenge the onsite emergency power system. Failure of both emergency diesels would result in a station blackout. The consequential loss of seal injection and component cooling water to the reactor coolant pumps (RCP) thermal barrier could eventually lead to a RCP seal LOCA. Station blackout and RCP seal LOCA are both conditions of this scenario that can result in core uncovery and damage.

In order to determine vulnerabilities, the major accident categories were evaluated along with the top-ranking sequences contributing to CDF. For a summary of the PRA results and a detailed discussion of the top-ranked sequences refer to Section 1.4.

The Beaver Valley Unit 2 potential enhancements are listed in Table 5.2-1.

Table 5.2-1. Beaver Valley Unit 2 IPE Potential Enhancements

Vulnerability	Procedure or Design Enhancement	Impact of Enhancement	CDF Importance		Status
			Percent of CDF	Risk * Achievement Worth	
AC Power Generation Capability for Station Blackout	Provide Beaver Valley Units 1 and 2 with 4,160 V Bus Crosstie Capability	Adds a success path for blackout on Unit 2 when both Unit 1 diesel generators work, and vice versa	25.3	301	Intent Met. SAMAs 9, 11, 12, 154
RCP Seal Cooling for Station Blackout	Potential modifications under review	Reduced frequency of RCP seal LOCA resulting from blackout	18.8	**	Intent Met. SAMA 158
Loss of Emergency Switchgear Room HVAC	Enhanced Loss of HVAC Procedures	Confidence that operators will prevent thermal damage to switchgear	17.1	19,428	Intent Met. SAMA 157, further analysis shows that there is a long time for installation of temporary ventilation.
Fast 4,160 V Bus Transfer Failure	Explicit Procedure and Training on breaker repair or change out	Reduced frequency that breaker failures will challenge diesel generators	8.0	1.6	Intent Met SAMA 21
Pressurizer PORV sticking open after loss of offsite power	Eliminate challenge by defeating the 100% load rejection capability	Reduced frequency of pressurizer PORV sticking open	7.2	3.1	Intent Met. SAMA 156, turbine trip above 30% causes reactor trip.
Battery Capacity for steam generator level instruments for station blackout	Enhance procedures on shedding loads or using portable battery chargers. One train of the battery chargers will be powered from the site operable emergency diesel generator once the Station Blackout Unit crosstie modification is complete.	Extended operating time for steam generator level instruments for loss of all AC power scenarios	6.8	337	SAMA 3, 159
Reactor Trip breaker failure	Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	4.2	5.9	SAMA 155, Analysis shows that actions outside the control room cannot be performed quickly enough. PRA updates have reduced the contribution from ATWS events.

Note: * The risk achievement worth is the factor increase in CDF that would be realized if the failure probability of the affected system were increased to 1.0.
** Included in the AC power generation capability for station blackout risk achievement worth value.

5.3 PLANT IPEEE

Potential improvements to reduce the risk in dominant fire zones and to reduce seismic risk and risk from other external events were evaluated in the Beaver Valley Unit 2 IPEEE. The list of candidate improvements and their status is documented in the IPEEE and reproduced in Table 3.1.2-1 in this report.

5.4 INDUSTRY SAMA CANDIDATES

The generic PWR enhancement list from Table 14 of Reference 24 was included in the list of Phase I SAMA candidates to assure adequate consideration of potential enhancements identified by other industry studies.

5.5 PLANT STAFF INPUT TO SAMA CANDIDATES

The Beaver Valley plant staff provided plant specific items that were included in the evaluation. These are identified in the list of SAMA candidates by their source.

5.6 LIST OF PHASE I SAMA CANDIDATES

Table 5.6-1 provides the combined list of potential SAMA candidates considered in the Beaver Valley Unit 2 SAMA analysis. From this table it can be seen that 190 SAMA candidates were identified for consideration.

Table 5.6-1 List of SAMA Candidates

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
1	Provide additional DC battery capacity.	Extended DC power availability during an SBO.	AC/DC	1, C
2	Replace lead-acid batteries with fuel cells.	Extended DC power availability during an SBO.	AC/DC	1
3	Add additional battery charger or portable, diesel-driven battery charger to existing DC system.	Improved availability of DC power system.	AC/DC	1, C
4	Improve DC bus load shedding.	Extended DC power availability during an SBO.	AC/DC	1
5	Provide DC bus cross-ties.	Improved availability of DC power system.	AC/DC	1
6	Provide additional DC power to the 120/240V vital AC system.	Increased availability of the 120 V vital AC bus.	AC/DC	1
7	Add an automatic feature to transfer the 120V vital AC bus from normal to standby power.	Increased availability of the 120 V vital AC bus.	AC/DC	1
8	Increase training on response to loss of two 120V AC buses which causes inadvertent actuation signals.	Improved chances of successful response to loss of two 120V AC buses.	AC/DC	1
9	Provide an additional diesel generator.	Increased availability of on-site emergency AC power.	AC/DC	1
10	Revise procedure to allow bypass of diesel generator trips.	Extended diesel generator operation.	AC/DC	1
11	Improve 4.16-kV bus cross-tie ability.	Increased availability of on-site AC power.	AC/DC	1, A
12	Create AC power cross-tie capability with other unit (multi-unit site)	Increased availability of on-site AC power.	AC/DC	1, A
13	Install an additional, buried off-site power source.	Reduced probability of loss of off-site power.	AC/DC	1
14	Install a gas turbine generator.	Increased availability of on-site AC power.	AC/DC	1
15	Install tornado protection on gas turbine generator.	Increased availability of on-site AC power.	AC/DC	1
16	Improve uninterruptible power supplies.	Increased availability of power supplies supporting front-line equipment.	AC/DC	1
17	Create a cross-tie for diesel fuel oil (multi-unit site).	Increased diesel generator availability.	AC/DC	1
18	Develop procedures for replenishing diesel fuel oil.	Increased diesel generator availability.	AC/DC	1
19	Use fire water system as a backup source for diesel cooling.	Increased diesel generator availability.	AC/DC	1
20	Add a new backup source of diesel cooling.	Increased diesel generator availability.	AC/DC	1
21	Develop procedures to repair or replace failed 4 KV breakers.	Increased probability of recovery from failure of breakers that transfer 4.16 kV non-emergency buses from unit station service transformers.	AC/DC	1, A
22	In training, emphasize steps in recovery of off-site power after an SBO.	Reduced human error probability during off-site power recovery.	AC/DC	1
23	Develop a severe weather conditions procedure.	Improved off-site power recovery following external weather-related events.	AC/DC	1
24	Bury off-site power lines.	Improved off-site power reliability during severe weather.	AC/DC	1
25	Install an independent active or passive high pressure injection system.	Improved prevention of core melt sequences.	Core Cooling	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
26	Provide an additional high pressure injection pump with independent diesel.	Reduced frequency of core melt from small LOCA and SBO sequences.	Core Cooling	1
27	Revise procedure to allow operators to inhibit automatic vessel depressurization in non-ATWS scenarios.	Extended HPCI and RCIC operation.	Core Cooling	1
28	Add a diverse low pressure injection system.	Improved injection capability.	Core Cooling	1
29	Provide capability for alternate injection via diesel-driven fire pump.	Improved injection capability.	Core Cooling	1
30	Improve ECCS suction strainers.	Enhanced reliability of ECCS suction.	Core Cooling	1
31	Add the ability to manually align emergency core cooling system recirculation.	Enhanced reliability of ECCS suction.	Core Cooling	1
32	Add the ability to automatically align emergency core cooling system to recirculation mode upon refueling water storage tank depletion.	Enhanced reliability of ECCS suction.	Core Cooling	1
33	Provide hardware and procedure to refill the reactor water storage tank once it reaches a specified low level.	Extended reactor water storage tank capacity in the event of a steam generator tube rupture.	Core Cooling	1
34	Provide an in-containment reactor water storage tank.	Continuous source of water to the safety injection pumps during a LOCA event, since water released from a breach of the primary system collects in the in-containment reactor water storage tank, and thereby eliminates the need to realign the safety injection pumps for long-term post-LOCA recirculation.	Core Cooling	1
35	Throttle low pressure injection pumps earlier in medium or large-break LOCAs to maintain reactor water storage tank inventory.	Extended reactor water storage tank capacity.	Core Cooling	1
36	Emphasize timely recirculation alignment in operator training.	Reduced human error probability associated with recirculation failure.	Core Cooling	1
37	Upgrade the chemical and volume control system to mitigate small LOCAs.	For a plant like the Westinghouse AP600, where the chemical and volume control system cannot mitigate a small LOCA, an upgrade would decrease the frequency of core damage.	Core Cooling	1
38	Change the in-containment reactor water storage tank suction from four check valves to two check and two air-operated valves.	Reduced common mode failure of injection paths.	Core Cooling	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
39	Replace two of the four electric safety injection pumps with diesel-powered pumps.	Reduced common cause failure of the safety injection system. This SAMA was originally intended for the Westinghouse-CE System 80+, which has four trains of safety injection. However, the intent of this SAMA is to provide diversity within the high- and low-pressure safety injection systems.	Core Cooling	1
40	Provide capability for remote, manual operation of secondary side pilot-operated relief valves in a station blackout.	Improved chance of successful operation during station blackout events in which high area temperatures may be encountered (no ventilation to main steam areas).	Core Cooling	1
41	Create a reactor coolant depressurization system.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	Core Cooling	1
42	Make procedure changes for reactor coolant system depressurization.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	Core Cooling	1
43	Add redundant DC control power for SW pumps.	Increased availability of SW.	Cooling Water	1
44	Replace ECCS pump motors with air-cooled motors.	Elimination of ECCS dependency on component cooling system.	Cooling Water	1
45	Enhance procedural guidance for use of cross-tied component cooling or service water pumps.	Reduced frequency of loss of component cooling water and service water.	Cooling Water	1
46	Add a service water pump.	Increased availability of cooling water.	Cooling Water	1
47	Enhance the screen wash system.	Reduced potential for loss of SW due to clogging of screens.	Cooling Water	1
48	Cap downstream piping of normally closed component cooling water drain and vent valves.	Reduced frequency of loss of component cooling water initiating events, some of which can be attributed to catastrophic failure of one of the many single isolation valves.	Cooling Water	1
49	Enhance loss of component cooling water (or loss of service water) procedures to facilitate stopping the reactor coolant pumps.	Reduced potential for reactor coolant pump seal damage due to pump bearing failure.	Cooling Water	1
50	Enhance loss of component cooling water procedure to underscore the desirability of cooling down the reactor coolant system prior to seal LOCA.	Reduced probability of reactor coolant pump seal failure.	Cooling Water	1
51	Additional training on loss of component cooling water.	Improved success of operator actions after a loss of component cooling water.	Cooling Water	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
52	Provide hardware connections to allow another essential raw cooling water system to cool charging pump seals.	Reduced effect of loss of component cooling water by providing a means to maintain the charging pump seal injection following a loss of normal cooling water.	Cooling Water	1
53	On loss of essential raw cooling water, proceduralize shedding component cooling water loads to extend the component cooling water heat-up time.	Increased time before loss of component cooling water (and reactor coolant pump seal failure) during loss of essential raw cooling water sequences.	Cooling Water	1
54	Increase charging pump lube oil capacity.	Increased time before charging pump failure due to lube oil overheating in loss of cooling water sequences.	Cooling Water	1
55	Install an independent reactor coolant pump seal injection system, with dedicated diesel.	Reduced frequency of core damage from loss of component cooling water, service water, or station blackout.	Cooling Water	1
56	Install an independent reactor coolant pump seal injection system, without dedicated diesel.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	Cooling Water	1
57	Use existing hydro test pump for reactor coolant pump seal injection.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	Cooling Water	1
58	Install improved reactor coolant pump seals.	Reduced likelihood of reactor coolant pump seal LOCA.	Cooling Water	1
59	Install an additional component cooling water pump.	Reduced likelihood of loss of component cooling water leading to a reactor coolant pump seal LOCA.	Cooling Water	1
60	Prevent makeup pump flow diversion through the relief valves.	Reduced frequency of loss of reactor coolant pump seal cooling if spurious high pressure injection relief valve opening creates a flow diversion large enough to prevent reactor coolant pump seal injection.	Cooling Water	1
61	Change procedures to isolate reactor coolant pump seal return flow on loss of component cooling water, and provide (or enhance) guidance on loss of injection during seal LOCA.	Reduced frequency of core damage due to loss of seal cooling.	Cooling Water	1
62	Implement procedures to stagger high pressure safety injection pump use after a loss of service water.	Extended high pressure injection prior to overheating following a loss of service water.	Cooling Water	1
63	Use fire prevention system pumps as a backup seal injection and high pressure makeup source.	Reduced frequency of reactor coolant pump seal LOCA.	Cooling Water	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
64	Implement procedure and hardware modifications to allow manual alignment of the fire water system to the component cooling water system, or install a component cooling water header cross-tie.	Improved ability to cool residual heat removal heat exchangers.	Cooling Water	1
65	Install a digital feed water upgrade.	Reduced chance of loss of main feed water following a plant trip.	Feedwater/Condensate	1
66	Create ability for emergency connection of existing or new water sources to feedwater and condensate systems.	Increased availability of feedwater.	Feedwater/Condensate	1
67	Install an independent diesel for the condensate storage tank makeup pumps.	Extended inventory in CST during an SBO.	Feedwater/Condensate	1
68	Add a motor-driven feedwater pump.	Increased availability of feedwater.	Feedwater/Condensate	1
69	Install manual isolation valves around auxiliary feedwater turbine-driven steam admission valves.	Reduced dual turbine-driven pump maintenance unavailability.	Feedwater/Condensate	1
70	Install accumulators for turbine-driven auxiliary feedwater pump flow control valves.	Eliminates the need for local manual action to align nitrogen bottles for control air following a loss of off-site power.	Feedwater/Condensate	1
71	Install a new condensate storage tank (auxiliary feedwater storage tank).	Increased availability of the auxiliary feedwater system.	Feedwater/Condensate	1
72	Modify the turbine-driven auxiliary feedwater pump to be self-cooled.	Improved success probability during a station blackout.	Feedwater/Condensate	1
73	Proceduralize local manual operation of auxiliary feedwater system when control power is lost.	Extended auxiliary feedwater availability during a station blackout. Also provides a success path should auxiliary feedwater control power be lost in non-station blackout sequences.	Feedwater/Condensate	1
74	Provide hookup for portable generators to power the turbine-driven auxiliary feedwater pump after station batteries are depleted.	Extended auxiliary feedwater availability.	Feedwater/Condensate	1
75	Use fire water system as a backup for steam generator inventory.	Increased availability of steam generator water supply.	Feedwater/Condensate	1
76	Change failure position of condenser makeup valve if the condenser makeup valve fails open on loss of air or power.	Allows greater inventory for the auxiliary feedwater pumps by preventing condensate storage tank flow diversion to the condenser.	Feedwater/Condensate	1
77	Provide a passive, secondary-side heat-rejection loop consisting of a condenser and heat sink.	Reduced potential for core damage due to loss-of-feedwater events.	Feedwater/Condensate	1
78	Modify the startup feedwater pump so that it can be used as a backup to the emergency feedwater system, including during a station blackout scenario.	Increased reliability of decay heat removal.	Feedwater/Condensate	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
79	Replace existing pilot-operated relief valves with larger ones, such that only one is required for successful feed and bleed.	Increased probability of successful feed and bleed.	Feedwater/Condensate	1
80	Provide a redundant train or means of ventilation.	Increased availability of components dependent on room cooling.	HVAC	1
81	Add a diesel building high temperature alarm or redundant louver and thermostat.	Improved diagnosis of a loss of diesel building HVAC.	HVAC	1
82	Stage backup fans in switchgear rooms.	Increased availability of ventilation in the event of a loss of switchgear ventilation.	HVAC	1
83	Add a switchgear room high temperature alarm.	Improved diagnosis of a loss of switchgear HVAC.	HVAC	1
84	Create ability to switch emergency feedwater room fan power supply to station batteries in a station blackout.	Continued fan operation in a station blackout.	HVAC	1
85	Provide cross-unit connection of uninterruptible compressed air supply.	Increased ability to vent containment using the hardened vent.	IA/Nitrogen	1
86	Modify procedure to provide ability to align diesel power to more air compressors.	Increased availability of instrument air after a LOOP.	IA/Nitrogen	1
87	Replace service and instrument air compressors with more reliable compressors which have self-contained air cooling by shaft driven fans.	Elimination of instrument air system dependence on service water cooling.	IA/Nitrogen	1
88	Install nitrogen bottles as backup gas supply for safety relief valves.	Extended SRV operation time.	IA/Nitrogen	1
89	Improve SRV and MSIV pneumatic components.	Improved availability of SRVs and MSIVs.	IA/Nitrogen	1
90	Create a reactor cavity flooding system.	Enhanced debris cool ability, reduced core concrete interaction, and increased fission product scrubbing.	Containment Phen	1
91	Install a passive containment spray system.	Improved containment spray capability.	Containment Phen	1
92	Use the fire water system as a backup source for the containment spray system.	Improved containment spray capability.	Containment Phen	1
93	Install an unfiltered, hardened containment vent.	Increased decay heat removal capability for non-ATWS events, without scrubbing released fission products.	Containment Phen	1
94	Install a filtered containment vent to remove decay heat. Option 1: Gravel Bed Filter; Option 2: Multiple Venturi Scrubber	Increased decay heat removal capability for non-ATWS events, with scrubbing of released fission products.	Containment Phen	1
95	Enhance fire protection system and standby gas treatment system hardware and procedures.	Improved fission product scrubbing in severe accidents.	Containment Phen	1
96	Provide post-accident containment inerting capability.	Reduced likelihood of hydrogen and carbon monoxide gas combustion.	Containment Phen	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
97	Create a large concrete crucible with heat removal potential to contain molten core debris.	Increased cooling and containment of molten core debris. Molten core debris escaping from the vessel is contained within the crucible and a water cooling mechanism cools the molten core in the crucible, preventing melt-through of the basemat.	Containment Phen	1
98	Create a core melt source reduction system.	Increased cooling and containment of molten core debris. Refractory material would be placed underneath the reactor vessel such that a molten core falling on the material would melt and combine with the material. Subsequent spreading and heat removal from the vitrified compound would be facilitated, and concrete attack would not occur.	Containment Phen	1
99	Strengthen primary/secondary containment (e.g., add ribbing to containment shell).	Reduced probability of containment over-pressurization.	Containment Phen	1
100	Increase depth of the concrete base mat or use an alternate concrete material to ensure melt-through does not occur.	Reduced probability of basemat melt-through.	Containment Phen	1
101	Provide a reactor vessel exterior cooling system.	Increased potential to cool a molten core before it causes vessel failure, by submerging the lower head in water.	Containment Phen	1
102	Construct a building to be connected to primary/secondary containment and maintained at a vacuum.	Reduced probability of containment over-pressurization.	Containment Phen	1
103	Institute simulator training for severe accident scenarios.	Improved arrest of core melt progress and prevention of containment failure.	Containment Phen	1
104	Improve leak detection procedures.	Increased piping surveillance to identify leaks prior to complete failure. Improved leak detection would reduce LOCA frequency.	Containment Phen	1
105	Delay containment spray actuation after a large LOCA.	Extended reactor water storage tank availability.	Containment Phen	1
106	Install automatic containment spray pump header throttle valves.	Extended time over which water remains in the reactor water storage tank, when full containment spray flow is not needed.	Containment Phen	1
107	Install a redundant containment spray system.	Increased containment heat removal ability.	Containment Phen	1
108	Install an independent power supply to the hydrogen control system using either new batteries, a non-safety grade portable generator, existing station batteries, or existing AC/DC independent power supplies, such as the security system diesel.	Reduced hydrogen detonation potential.	Containment Phen	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
109	Install a passive hydrogen control system.	Reduced hydrogen detonation potential.	Containment Phen	1
110	Erect a barrier that would provide enhanced protection of the containment walls (shell) from ejected core debris following a core melt scenario at high pressure.	Reduced probability of containment failure.	Containment Phen	1
111	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	Reduced ISLOCA frequency.	Containment Bypass	1
112	Add redundant and diverse limit switches to each containment isolation valve.	Reduced frequency of containment isolation failure and ISLOCAs.	Containment Bypass	1
113	Increase leak testing of valves in ISLOCA paths.	Reduced ISLOCA frequency.	Containment Bypass	1
114	Install self-actuating containment isolation valves.	Reduced frequency of isolation failure.	Containment Bypass	1
115	Locate residual heat removal (RHR) inside containment	Reduced frequency of ISLOCA outside containment.	Containment Bypass	1
116	Ensure ISLOCA releases are scrubbed. One method is to plug drains in potential break areas so that break point will be covered with water.	Scrubbed ISLOCA releases.	Containment Bypass	1
117	Revise EOPs to improve ISLOCA identification.	Increased likelihood that LOCAs outside containment are identified as such. A plant had a scenario in which an RHR ISLOCA could direct initial leakage back to the pressurizer relief tank, giving indication that the LOCA was inside containment.	Containment Bypass	1
118	Improve operator training on ISLOCA coping.	Decreased ISLOCA consequences.	Containment Bypass	1
119	Institute a maintenance practice to perform a 100% inspection of steam generator tubes during each refueling outage.	Reduced frequency of steam generator tube ruptures.	Containment Bypass	1
120	Replace steam generators with a new design.	Reduced frequency of steam generator tube ruptures.	Containment Bypass	1
121	Increase the pressure capacity of the secondary side so that a steam generator tube rupture would not cause the relief valves to lift.	Eliminates release pathway to the environment following a steam generator tube rupture.	Containment Bypass	1
122	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture	Enhanced depressurization capabilities during steam generator tube rupture.	Containment Bypass	1
123	Proceduralize use of pressurizer vent valves during steam generator tube rupture sequences.	Backup method to using pressurizer sprays to reduce primary system pressure following a steam generator tube rupture.	Containment Bypass	1
124	Provide improved instrumentation to detect steam generator tube ruptures, such as Nitrogen-16 monitors).	Improved mitigation of steam generator tube ruptures.	Containment Bypass	1
125	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.	Reduced consequences of a steam generator tube rupture.	Containment Bypass	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
126	Install a highly reliable (closed loop) steam generator shell-side heat removal system that relies on natural circulation and stored water sources	Reduced consequences of a steam generator tube rupture.	Containment Bypass	1
127	Revise emergency operating procedures to direct isolation of a faulted steam generator.	Reduced consequences of a steam generator tube rupture.	Containment Bypass	1
128	Direct steam generator flooding after a steam generator tube rupture, prior to core damage.	Improved scrubbing of steam generator tube rupture releases.	Containment Bypass	1
129	Vent main steam safety valves in containment.	Reduced consequences of a steam generator tube rupture.	Containment Bypass	1
130	Add an independent boron injection system.	Improved availability of boron injection during ATWS.	ATWS	1
131	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	Improved equipment availability after an ATWS.	ATWS	1
132	Provide an additional control system for rod insertion (e.g., AMSAC).	Improved redundancy and reduced ATWS frequency.	ATWS	1
133	Install an ATWS sized filtered containment vent to remove decay heat.	Increased ability to remove reactor heat from ATWS events.	ATWS	1
134	Revise procedure to bypass MSIV isolation in turbine trip ATWS scenarios.	Affords operators more time to perform actions. Discharge of a substantial fraction of steam to the main condenser (i.e., as opposed to into the primary containment) affords the operator more time to perform actions (e.g., SLC injection, lower water level, depressurize RPV) than if the main condenser was unavailable, resulting in lower human error probabilities.	ATWS	1
135	Revise procedure to allow override of low pressure core injection during an ATWS event.	Allows immediate control of low pressure core injection. On failure of high pressure core injection and condensate, some plants direct reactor depressurization followed by five minutes of automatic low pressure core injection.	ATWS	1
136	Install motor generator set trip breakers in control room.	Reduced frequency of core damage due to an ATWS.	ATWS	1
137	Provide capability to remove power from the bus powering the control rods.	Decreased time required to insert control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	ATWS	1
138	Improve inspection of rubber expansion joints on main condenser.	Reduced frequency of internal flooding due to failure of circulating water system expansion joints.	Internal Flooding	1

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
139	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment.	Prevents flood propagation.	Internal Flooding	1
140	Increase seismic ruggedness of plant components.	Increased availability of necessary plant equipment during and after seismic events.	Seismic Risk	1
141	Provide additional restraints for CO2 tanks.	Increased availability of fire protection given a seismic event.	Seismic Risk	1
142	Replace mercury switches in fire protection system.	Decreased probability of spurious fire suppression system actuation.	Fire Risk	1
143	Upgrade fire compartment barriers.	Decreased consequences of a fire.	Fire Risk	1
144	Install additional transfer and isolation switches.	Reduced number of spurious actuations during a fire.	Fire Risk	1
145	Enhance fire brigade awareness.	Decreased consequences of a fire.	Fire Risk	1
146	Enhance control of combustibles and ignition sources.	Decreased fire frequency and consequences.	Fire Risk	1
147	Install digital large break LOCA protection system.	Reduced probability of a large break LOCA (a leak before break).	Other	1
148	Enhance procedures to mitigate large break LOCA.	Reduced consequences of a large break LOCA.	Other	1
149	Install computer aided instrumentation system to assist the operator in assessing post-accident plant status.	Improved prevention of core melt sequences by making operator actions more reliable.	Other	1
150	Improve maintenance procedures.	Improved prevention of core melt sequences by increasing reliability of important equipment.	Other	1
151	Increase training and operating experience feedback to improve operator response.	Improved likelihood of success of operator actions taken in response to abnormal conditions.	Other	1
152	Develop procedures for transportation and nearby facility accidents.	Reduced consequences of transportation and nearby facility accidents.	Other	1
153	Install secondary side guard pipes up to the main steam isolation valves.	Prevents secondary side depressurization should a steam line break occur upstream of the main steam isolation valves. Also guards against or prevents consequential multiple steam generator tube ruptures following a main steam line break event.	Other	1
154	Provide Beaver Valley Units 1 and 2 with 4,160 V Bus Crosstie Capability	Adds a success path for blackout on Unit 2 when both Unit 1 diesel generators work, and vice versa	AC/DC	A
155	Reactor Trip breaker failure , Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	ATWS	A
156	Operate plant with all PORV block valves open or provide procedures to open block valves when Main Feedwater is lost.	Increased pressure relief capacity to prevent reactor vessel rupture during ATWS.	ATWS	A

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
157	Loss of Emergency Switchgear Room HVAC , Enhanced Loss of HVAC Procedures	Confidence that operators will prevent thermal damage to switchgear	HVAC	A
158	RCP Seal Cooling for Station Blackout, Potential modifications under review	Reduced frequency of RCP seal LOCA resulting from blackout	Cooling Water	A
159	Battery Capacity for steam generator level instruments for station blackout, Enhance procedures on shedding loads or using portable battery chargers. One train of the battery chargers will be powered from the site operable emergency diesel generator once the Station Blackout Unit crosstie modification is complete.	Extended operating time for steam generator level instruments for less of all AC power scenarios	AC/DC	A
160	Pressurizer PORV sticking open after loss of offsite power, Eliminate challenge by defeating the 100% load rejection capability	Reduced frequency of pressurizer PORV sticking open	Core Cooling	A
161	Fast 4,160 V Bus Transfer Failure, Explicit Procedure and Training on breaker repair or change out	Reduced frequency that breaker failures will challenge diesel generators	AC/DC	A
162	Provide a dedicated diesel driven feed water pump with supply tank to provide an additional source of water for SG tube coverage during SGTR events.	This would eliminate the LERF category and reduce all SGTR events to Small Early Releases.	Core Cooling	C
163	Modify Loss of DC AOP to proceduralize the use of backup battery chargers.	Provide better reliability of the DC busses.	AC/DC	C
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	Containment Bypass	C
165	Install an independent RCP Seal Injection system.	Reduce frequency of RCP seal failure.	Cooling Water	C
166	Provide additional emergency 125V DC battery capability.	Better coping for long term station blackouts	AC/DC	C
167	Increase the seismic ruggedness of the emergency 125V DC battery block walls	Reduce failure of batteries due to seismic induced failure of battery room block walls.	Seismic Risk	C
168	Install fire barriers for HVAC fans in the cable spreading room	Eliminate failure of fire propagating from one fan to another.	Fire Risk	C
169	Improve operator performance. Operator fails to align makeup to RWST - SGTR, secondary leak	Top 10 operator actions OPRWM1	Human Reliability	D
170	Improve operator performance. Operator fails to manually trip reactor - ATWS	Top 10 operator actions OPROT1	Human Reliability	D
171	Improve operator performance. Operator fails to realign main feedwater - no SI signal	Top 10 operator actions OPROF2	Human Reliability	D

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
172	Improve operator performance. Operator fails to initiate AFW following transient	Top 10 operator actions OPROS6	Human Reliability	D
173	Improve operator performance. Operator aligns spare battery charger 2-9 to 2-2	Top 10 operator actions OPRDC2	Human Reliability	D
174	Improve operator performance. Operator aligns spare battery charger 2-7 to 2-1	Top 10 operator actions OPRDC1	Human Reliability	D
175	Improve operator performance. Operator fails to initiate bleed and feed	Top 10 operator actions OPROB2	Human Reliability	D
176	Improve operator performance. Operator fails to trip RCP during loss of CCP	Top 10 operator actions OPROC1	Human Reliability	D
177	Improve operator performance. Operator fails to initiate bleed and feed	Top 10 operator actions OPROB1	Human Reliability	D
178	Improve operator performance. Operator fails to identify ruptured SG or initiate isolation	Top 10 operator actions OPRSL1	Human Reliability	D
179	Reduce risk contribution from fires originating in Zone CB-3, causing a total loss of main feedwater and auxiliary feedwater with subsequent failure of feed and bleed.	Elimination or improved mitigation of fires in this area.	Fire Risk	B
180	Reduce risk contribution from fires originating in zone CT-1, causing a total loss of service water.	Elimination or improved mitigation of fires in this area.	Fire Risk	B
181	Reduce risk contribution from fires originating in zone SB-4, causing a total loss of normal AC power with subsequent failure of emergency AC power and station crosstie leading to station blackout.	Elimination or improved mitigation of fires in this area.	Fire Risk	B
182	Reduce risk contribution from fires originating in zone CV-1, causing failure of service water	Elimination or improved mitigation of fires in this area.	Fire Risk	B
183	Reduce risk contribution from fires originating in zone CV-3, causing failure of component cooling water (thermal barrier cooling) and service water with subsequent failure of reactor coolant pump seal injection.	Elimination or improved mitigation of fires in this area.	Fire Risk	B
184	Reduce risk contribution from fires in EDG building, fire initiator DG1L1A.	Elimination or improved mitigation of fires in this area.	Fire Risk	D
185	Reduce risk contribution from fires in EDG building, fire initiator DG2L1A.	Elimination or improved mitigation of fires in this area.	Fire Risk	D
186	Increase seismic ruggedness of the ERF Substation batteries. This refers only to the battery racks, not the entire structure.	Increased reliability of the ERF diesel following seismic events	Seismic Risk	F
187	Reduce risk contribution from internal flooding in cable vault area, CV-2 735', by reducing the frequency of the event or by improvements in mitigation of the resulting flooding.	Eliminate or mitigate the consequences of a flood in this area.	Internal Flooding	D

Table 5.6-1 List of SAMA Candidates (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Focus of SAMA	Source
188	Reduce risk contribution from internal flooding in Safeguards building, N&S. (Source of flooding is a RWST line.	Eliminate or mitigate the consequences of a flood in this area.	Internal Flooding	D
189	Install Westinghouse RCP Shutdown seals to work with high temperature O-Rings.	Reduced seal LOCA probability	Cooling Water	F
190	Add guidance to the SAMG to consider post-accident cross-tie of the two unit containments through the gaseous waste system.	Reduce or prevent the release of radionuclides as a result of containment failure.	Containment	E

Note 1: The source references are:

- 1 NEI 05-01 (Reference 24)
- A IPE (Reference 4)
- B IPEEE (Reference 5
- C Beaver Valley Power Station ELT 2004 Strategic Action Plan - Safe Plant Operations (Reference 39)
- D BV2REV4 PRA results (Reference 27)
- E NISYS-1092-C006 (Reference 37)
- F Undocumented conversations/interviews with site personnel.

6 PHASE I ANALYSIS

A preliminary screening of the complete list of SAMA candidates was performed to limit the number of SAMAs for which detailed analysis in Phase II was necessary. The screening criteria used in the Phase I analysis are described below.

- ***Screening Criterion A - Not Applicable***: If a SAMA candidate did not apply to the Beaver Valley Unit 2 plant design, it was not retained.
- ***Screening Criterion B - Already Implemented or Intent Met***: If a SAMA candidate had already been implemented at the Beaver Valley Unit 2 or the intent of the candidate is met, it was not retained.
- ***Screening Criterion C - Combined***: If a SAMA candidate was similar in nature and could be combined with another SAMA candidate to develop a more comprehensive or plant-specific SAMA candidate, only the combined SAMA candidate was retained.
- ***Screening Criterion D - Excessive Implementation Cost***: If a SAMA required extensive changes that will obviously exceed the maximum benefit (Section 4.5), even without an implementation cost estimate, it was not retained.
- ***Screening Criterion E - Very Low Benefit***: If a SAMA from an industry document was related to a non-risk significant system for which change in reliability is known to have negligible impact on the risk profile, it was not retained. (No SAMAs were screened using this criterion.)

Table 6-1 presents the list of Phase I SAMA candidates and provides the disposition of each candidate along with the applicable screening criterion associated with each candidate. Those candidates that have not been screened by application of these criteria are evaluated further in the Phase II analysis (Section 7). It can be seen from this table that 134 SAMAs were screened from the analysis during Phase 1 and that 56 SAMAs passed into the next phase of the analysis.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
15	Install tornado protection on gas turbine generator.	Increased availability of on-site AC power.	Yes	A - Not Applicable	Not applicable. Plant does not have gas turbine generator.
27	Revise procedure to allow operators to inhibit automatic vessel depressurization in non-ATWS scenarios.	Extended HPCI and RCIC operation.	Yes	A - Not Applicable	Not applicable. Description of HPCI and RCIC use implies BWR item.
35	Throttle low pressure injection pumps earlier in medium or large-break LOCAs to maintain reactor water storage tank inventory.	Extended reactor water storage tank capacity.	Yes	A - Not Applicable	Per Expert Panel: LHI only used in LBLOCA sequences, throttling not considered. Long-term cooling is sump recirc.
38	Change the in-containment reactor water storage tank suction from four check valves to two check and two air-operated valves.	Reduced common mode failure of injection paths.	Yes	A - Not Applicable	Not Applicable. Beaver Valley suction of different design.
52	Provide hardware connections to allow another essential raw cooling water system to cool charging pump seals.	Reduced effect of loss of component cooling water by providing a means to maintain the charging pump seal injection following a loss of normal cooling water.	Yes	A - Not Applicable	Charging pump seals do not require cooling.
57	Use existing hydro test pump for reactor coolant pump seal injection.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	Yes	A - Not Applicable	Cannot be implemented due to design limitations using existing pump. The pressure pulses from the positive displacement pump will damage the seal, leading to seal failure
62	Implement procedures to stagger high pressure safety injection pump use after a loss of service water.	Extended high pressure injection prior to overheating following a loss of service water.	Yes	A - Not Applicable	Due to the estimated time of 12 minutes for pump failure following loss of lube oil cooling and the restricted start duty times of 45 minutes between starts, this is not considered a viable option.
63	Use fire prevention system pumps as a backup seal injection and high pressure makeup source.	Reduced frequency of reactor coolant pump seal LOCA.	Yes	A - Not Applicable	Not applicable. Fire pumps do not have sufficient discharge pressure for high pressure makeup source.
69	Install manual isolation valves around auxiliary feedwater turbine-driven steam admission valves.	Reduced dual turbine-driven pump maintenance unavailability.	Yes	A - Not Applicable	Not Applicable. Beaver Valley does not have dual turbine design.
70	Install accumulators for turbine-driven auxiliary feedwater pump flow control valves.	Eliminates the need for local manual action to align nitrogen bottles for control air following a loss of off-site power.	Yes	A - Not Applicable	Not applicable. TDAFW has a mechanical FCV. Steam generator FCV are electro-hydraulic with hand pump backup.
76	Change failure position of condenser makeup valve if the condenser makeup valve fails open on loss of air or power.	Allows greater inventory for the auxiliary feedwater pumps by preventing condensate storage tank flow diversion to the condenser.	Yes	A - Not Applicable	Not applicable. Condenser makeup valve fails closed.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
84	Create ability to switch emergency feedwater room fan power supply to station batteries in a station blackout.	Continued fan operation in a station blackout.	Yes	A - Not Applicable	TDAFW pump rated for high temperature environment. No backup ventilation is needed.
88	Install nitrogen bottles as backup gas supply for safety relief valves.	Extended SRV operation time.	Yes	A - Not Applicable	PORVs are self-actuated, no dependency on air. The pressurizer SRVs and PORVs are self-actuated, no dependency on air. The steam generator ADVs are electro-hydraulic, no dependency on air.
105	Delay containment spray actuation after a large LOCA.	Extended reactor water storage tank availability.	Yes	A - Not Applicable	Delaying the containment spray actuation following a large LOCA, would potentially result in exceeding containment design pressure and/or temperature.
108	Install an independent power supply to the hydrogen control system using either new batteries, a non-safety grade portable generator, existing station batteries, or existing AC/DC independent power supplies, such as the security system diesel.	Reduced hydrogen detonation potential.	Yes	A - Not Applicable	Hydrogen recombiners previously abandoned in-place.
109	Install a passive hydrogen control system.	Reduced hydrogen detonation potential.	Yes	A - Not Applicable	Hydrogen recombiners previously abandoned in-place.
134	Revise procedure to bypass MSIV isolation in turbine trip ATWS scenarios.	Affords operators more time to perform actions. Discharge of a substantial fraction of steam to the main condenser (i.e., as opposed to into the primary containment) affords the operator more time to perform actions (e.g., SLC injection, lower water level, depressurize RPV) than if the main condenser was unavailable, resulting in lower human error probabilities.	Yes	A - Not Applicable	Expert Panel - Determined this is a BWR issue.
135	Revise procedure to allow override of low pressure core injection during an ATWS event.	Allows immediate control of low pressure core injection. On failure of high pressure core injection and condensate, some plants direct reactor depressurization followed by five minutes of automatic low pressure core injection.	Yes	A - Not Applicable	Not applicable. This should be limited to BWR ATWS response.
139	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment.	Prevents flood propagation.	Yes	A - Not Applicable	This was not identified as an internal flooding initiator of concern.
140	Increase seismic ruggedness of plant components.	Increased availability of necessary plant equipment during and after seismic events.	Yes	A - Not Applicable	Specific identified items addressed in other SAMAs (see SAMA 186)
141	Provide additional restraints for CO2 tanks.	Increased availability of fire protection given a seismic event.	Yes	A - Not Applicable	Seismic PRA and walkdowns did not identify this as a contributor.
143	Upgrade fire compartment barriers.	Decreased consequences of a fire.	Yes	A - Not Applicable	Individual fires of concern are addressed specifically, see SAMAs 179, 180, 181, 182, 183, 184, 185.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
167	Increase the seismic ruggedness of the emergency 125V DC battery block walls	Reduce failure of batteries due to seismic induced failure of battery room block walls.	Yes	A - Not Applicable	Not applicable. Unit 2 design is different than Unit 1.
168	Install fire barriers for HVAC fans in the cable spreading room	Eliminate failure of fire propagating from one fan to another.	Yes	A - Not Applicable	Not applicable. This item only applicable to Unit 1
182	Reduce risk contribution from fires originating in zone CV-1, causing failure of service water	Elimination or improved mitigation of fires in this area.	Yes	A - Not Applicable	Fires in this area only cause loss of "A" train of service water. Revisions to the PRA model show that fires in this area contribute less that 0,02% of total CDF.
189	Install Westinghouse RCP Shutdown seals to work with high temperature O-Rings.	Reduced seal LOCA probability	Yes	A - Not Applicable	Not applicable. This seal is not available.
7	Add an automatic feature to transfer the 120V vital AC bus from normal to standby power.	Increased availability of the 120 V vital AC bus.	Yes	B - Intent Met	Intent met. Part of UPS design.
8	Increase training on response to loss of two 120V AC buses which causes inadvertent actuation signals.	Improved chances of successful response to loss of two 120V AC buses.	Yes	B - Intent Met	Loss of a single 120 VAC bus will induce transient. Procedures and training exist for operator response to loss of vital bus. If loss of two occurs, operators will implement the procedures for loss of both.
9	Provide an additional diesel generator.	Increased availability of on-site emergency AC power.	Yes	B - Intent Met	Intent met though SBO cross-tie to other unit.
10	Revise procedure to allow bypass of diesel generator trips.	Extended diesel generator operation.	Yes	B - Intent Met	Intent met. All non-essential EDG trips are bypassed upon emergency start.
11	Improve 4.16-kV bus cross-tie ability.	Increased availability of on-site AC power.	Yes	B - Intent Met	Intent met. Modifications installed.
12	Create AC power cross-tie capability with other unit (multi-unit site)	Increased availability of on-site AC power.	Yes	B - Intent Met	Intent met. Modifications installed.
16	Improve uninterruptible power supplies.	Increased availability of power supplies supporting front-line equipment.	Yes	B - Intent Met	Intent met. Inverters upgraded.
18	Develop procedures for replenishing diesel fuel oil.	Increased diesel generator availability.	Yes	B - Intent Met	Intent met. Procedure exists.
19	Use fire water system as a backup source for diesel cooling.	Increased diesel generator availability.	Yes	B - Intent Met	Intent met. Procedure exists.
20	Add a new backup source of diesel cooling.	Increased diesel generator availability.	Yes	B - Intent Met	Intent met. Cross-connections and backups available.
21	Develop procedures to repair or replace failed 4 KV breakers.	Increased probability of recovery from failure of breakers that transfer 4.16 kV non-emergency buses from unit station service transformers.	Yes	B - Intent Met	Intent met. Procedure exists.
22	In training, emphasize steps in recovery of off-site power after an SBO.	Reduced human error probability during off-site power recovery.	Yes	B - Intent Met	Intent met. Included in training.
23	Develop a severe weather conditions procedure.	Improved off-site power recovery following external weather-related events.	Yes	B - Intent Met	Intent met. Procedure exists.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
30	Improve ECCS suction strainers.	Enhanced reliability of ECCS suction.	Yes	B - Intent Met	Sump improvements being installed with a phased implementation process IAW GL 2004-02.
31	Add the ability to manually align emergency core cooling system recirculation.	Enhanced reliability of ECCS suction.	Yes	B - Intent Met	Intent met. Automatic with manual backup.
32	Add the ability to automatically align emergency core cooling system to recirculation mode upon refueling water storage tank depletion.	Enhanced reliability of ECCS suction.	Yes	B - Intent Met	Intent met. Automatic with manual backup.
33	Provide hardware and procedure to refill the reactor water storage tank once it reaches a specified low level.	Extended reactor water storage tank capacity in the event of a steam generator tube rupture.	Yes	B - Intent Met	Intent met. Procedure exists.
36	Emphasize timely recirculation alignment in operator training.	Reduced human error probability associated with recirculation failure.	Yes	B - Intent Met	Intent met. Included in training.
40	Provide capability for remote, manual operation of secondary side pilot-operated relief valves in a station blackout.	Improved chance of successful operation during station blackout events in which high area temperatures may be encountered (no ventilation to main steam areas).	Yes	B - Intent Met	Intent met. Valves can be operated locally using hydraulic actuator.
42	Make procedure changes for reactor coolant system depressurization.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	Yes	B - Intent Met	Intent met. Procedure exists.
43	Add redundant DC control power for SW pumps.	Increased availability of SW.	Yes	B - Intent Met	Swing Pump fulfills this function, Standby Service Water Pumps can be aligned to either header.
44	Replace ECCS pump motors with air-cooled motors.	Elimination of ECCS dependency on component cooling system.	Yes	B - Intent Met	Intent met. ECCS pump motors are air cooled.
45	Enhance procedural guidance for use of cross-tied component cooling or service water pumps.	Reduced frequency of loss of component cooling water and service water.	Yes	B - Intent Met	Intent met. Procedure exists.
46	Add a service water pump.	Increased availability of cooling water.	Yes	B - Intent Met	Intent met. The alternate intake facility fulfills this function. An installed spare service water pump that can be aligned to either bus on either loop. Standby service water pumps auto-start on low header pressure.
47	Enhance the screen wash system.	Reduced potential for loss of SW due to clogging of screens.	Yes	B - Intent Met	Intent met. Alternate Intake Facility. Alternate intake facility provides redundancy, there is a PM and monitoring program in place for the screens and screen wash system.
48	Cap downstream piping of normally closed component cooling water drain and vent valves.	Reduced frequency of loss of component cooling water initiating events, some of which can be attributed to catastrophic failure of one of the many single isolation valves.	Yes	B - Intent Met	Intent met. Vents and Drains are capped.
49	Enhance loss of component cooling water (or loss of service water) procedures to facilitate stopping the reactor coolant pumps.	Reduced potential for reactor coolant pump seal damage due to pump bearing failure.	Yes	B - Intent Met	Intent met. Procedure exists.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
50	Enhance loss of component cooling water procedure to underscore the desirability of cooling down the reactor coolant system prior to seal LOCA.	Reduced probability of reactor coolant pump seal failure.	Yes	B - Intent Met	Intent met. Procedure exists.
51	Additional training on loss of component cooling water.	Improved success of operator actions after a loss of component cooling water.	Yes	B - Intent Met	Intent met. Loss of component cooling water included in training program.
53	On loss of essential raw cooling water, proceduralize shedding component cooling water loads to extend the component cooling water heat-up time.	Increased time before loss of component cooling water (and reactor coolant pump seal failure) during loss of essential raw cooling water sequences.	Yes	B - Intent Met	Intent met. Procedure exists.
58	Install improved reactor coolant pump seals.	Reduced likelihood of reactor coolant pump seal LOCA.	Yes	B - Intent Met	Intent met. New design RCP seals installed. See also SAMAs 158 & 189
59	Install an additional component cooling water pump.	Reduced likelihood of loss of component cooling water leading to a reactor coolant pump seal LOCA.	Yes	B - Intent Met	Installed spare pump.
60	Prevent makeup pump flow diversion through the relief valves.	Reduced frequency of loss of reactor coolant pump seal cooling if spurious high pressure injection relief valve opening creates a flow diversion large enough to prevent reactor coolant pump seal injection.	Yes	B - Intent Met	There are relief valves on the charging system piping for the purpose of thermal pressure buildup following containment isolation. The relief valves set points are above the shutoff head of the charging pumps and would not be expected to lift.
61	Change procedures to isolate reactor coolant pump seal return flow on loss of component cooling water, and provide (or enhance) guidance on loss of injection during seal LOCA.	Reduced frequency of core damage due to loss of seal cooling.	Yes	B - Intent Met	Intent met. Procedure exists.
66	Create ability for emergency connection of existing or new water sources to feedwater and condensate systems.	Increased availability of feedwater.	Yes	B - Intent Met	Intent met. AFW has backup from service water.
67	Install an independent diesel for the condensate storage tank makeup pumps.	Extended inventory in CST during an SBO.	Yes	B - Intent Met	Have procedure to makeup from PPDWST. Also have ability to gravity feed from DWST to PPDWST. Procedure being developed.
68	Add a motor-driven feedwater pump.	Increased availability of feedwater.	Yes	B - Intent Met	Intent met. Unit has a motor driven startup feedwater pump with suction from the main condenser. Main feedwater pumps are motor driven.
71	Install a new condensate storage tank (auxiliary feedwater storage tank).	Increased availability of the auxiliary feedwater system.	Yes	B - Intent Met	Demin water storage tank is available to refill the PPDWST.
72	Modify the turbine-driven auxiliary feedwater pump to be self-cooled.	Improved success probability during a station blackout.	Yes	B - Intent Met	Intent met. TDAFW is self cooled.
73	Proceduralize local manual operation of auxiliary feedwater system when control power is lost.	Extended auxiliary feedwater availability during a station blackout. Also provides a success path should auxiliary feedwater control power be lost in non-station blackout sequences.	Yes	B - Intent Met	Intent met. Procedure exists.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
75	Use fire water system as a backup for steam generator inventory.	Increased availability of steam generator water supply.	Yes	B - Intent Met	Intent met. Service Water and River Water systems can be used as backup water source for AFW.
79	Replace existing pilot-operated relief valves with larger ones, such that only one is required for successful feed and bleed.	Increased probability of successful feed and bleed.	Yes	B - Intent Met	Beaver Valley has three PORVs, only one is required for successful feed and bleed.
80	Provide a redundant train or means of ventilation.	Increased availability of components dependent on room cooling.	Yes	B - Intent Met	EDG building HVAC is the only identified applicable HVAC system. Portable fans are available as backup.
81	Add a diesel building high temperature alarm or redundant louver and thermostat.	Improved diagnosis of a loss of diesel building HVAC.	Yes	B - Intent Met	High temperature alarm exists. Actions on high temperature include opening doors.
82	Stage backup fans in switchgear rooms.	Increased availability of ventilation in the event of a loss of switchgear ventilation.	Yes	B - Intent Met	Intent met. Fans are not staged in switchgear room, but are nearby.
83	Add a switchgear room high temperature alarm.	Improved diagnosis of a loss of switchgear HVAC.	Yes	B - Intent Met	No high temperature alarm, but multiple alarms for fan trips. Backup fans are available and a procedure exists for implementing temporary ventilation. Analysis shows long time available to implement temporary ventilation. Operators are trained on the procedure for temporary ventilation.
85	Provide cross-unit connection of uninterruptible compressed air supply.	Increased ability to vent containment using the hardened vent.	Yes	B - Intent Met	Have a third train of station air installed that is supplied from a diesel air compressor.
86	Modify procedure to provide ability to align diesel power to more air compressors.	Increased availability of instrument air after a LOOP.	Yes	B - Intent Met	Intent met. Third train of station air installed that is supplied from a diesel air compressor.
87	Replace service and instrument air compressors with more reliable compressors which have self-contained air cooling by shaft driven fans.	Elimination of instrument air system dependence on service water cooling.	Yes	B - Intent Met	Have an installed third train of station air supplied by a diesel air compressor.
92	Use the fire water system as a backup source for the containment spray system.	Improved containment spray capability.	Yes	B - Intent Met	Intent met. Procedure exists.
93	Install an unfiltered, hardened containment vent.	Increased decay heat removal capability for non-ATWS events, without scrubbing released fission products.	Yes	B - Intent Met	SAMG guidance contains guidance for a number of containment venting paths. Although not a dedicated hardened vent, redundant and separate venting paths exist.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
95	Enhance fire protection system and standby gas treatment system hardware and procedures.	Improved fission product scrubbing in severe accidents.	Yes	B - Intent Met	Intent met. In SAMG.
103	Institute simulator training for severe accident scenarios.	Improved arrest of core melt progress and prevention of containment failure.	Yes	B - Intent Met	Intent met. Included in training program.
106	Install automatic containment spray pump header throttle valves.	Extended time over which water remains in the reactor water storage tank, when full containment spray flow is not needed.	Yes	B - Intent Met	Implemented IAW EOPs.
114	Install self-actuating containment isolation valves.	Reduced frequency of isolation failure.	Yes	B - Intent Met	Intent met. AOV, MOV and CV containment isolation valves; those that are required to close are AOVs and fail closed on loss-of-air, or are administratively controlled closed, except CCP to RCP seal cooling.
115	Locate residual heat removal (RHR) inside containment	Reduced frequency of ISLOCA outside containment.	Yes	B - Intent Met	Intent met. RHS pumps are located inside containment.
116	Ensure ISLOCA releases are scrubbed. One method is to plug drains in potential break areas so that break point will be covered with water.	Scrubbed ISLOCA releases.	Yes	B - Intent Met	Break flow is expected to submerge the break location; in addition, the fission product releases would pass through building ventilation which is filtered through the supplemental leak collection and release system.
117	Revise EOPs to improve ISLOCA identification.	Increased likelihood that LOCAs outside containment are identified as such. A plant had a scenario in which an RHR ISLOCA could direct initial leakage back to the pressurizer relief tank, giving indication that the LOCA was inside containment.	Yes	B - Intent Met	Intent met. EOPs provide guidance to eliminate other routes.
123	Proceduralize use of pressurizer vent valves during steam generator tube rupture sequences.	Backup method to using pressurizer sprays to reduce primary system pressure following a steam generator tube rupture.	Yes	B - Intent Met	Intent met. Procedure exists.
124	Provide improved instrumentation to detect steam generator tube ruptures, such as Nitrogen-16 monitors).	Improved mitigation of steam generator tube ruptures.	Yes	B - Intent Met	Intent met. N-16 monitors installed.
127	Revise emergency operating procedures to direct isolation of a faulted steam generator.	Reduced consequences of a steam generator tube rupture.	Yes	B - Intent Met	Intent met by alternate means. Procedure EOP E-2 directs operators to isolate faulted SGs by closing all actuated or manual valves associated with the affected SG. SAMA 164 will enhance procedures to provide steps to isolate any stuck-open safety valves on a ruptured SG.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
128	Direct steam generator flooding after a steam generator tube rupture, prior to core damage.	Improved scrubbing of steam generator tube rupture releases.	Yes	B - Intent Met	Intent met by alternate means. Procedure EOP E-3 directs operators to feed ruptured SGs if the narrow range level is below 12%. SAMA 164, will enhance procedures to provide steps to; consider feeding a faulted-ruptured SG to provide continuous scrubbing (by maintaining ~12% to 50% narrow range SG level by throttling AFW flow to the ruptured SG), isolate any stuck-open safety valves on a ruptured SG, or close the RCS Loop Stop Valves on the ruptured SG to terminate or minimize the release.
132	Provide an additional control system for rod insertion (e.g., AMSAC).	Improved redundancy and reduced ATWS frequency.	Yes	B - Intent Met	Intent met. AMSAC installed.
138	Improve inspection of rubber expansion joints on main condenser.	Reduced frequency of internal flooding due to failure of circulating water system expansion joints.	Yes	B - Intent Met	Implemented - Program exists to inspect and replace expansion joints in the turbine building.
142	Replace mercury switches in fire protection system.	Decreased probability of spurious fire suppression system actuation.	Yes	B - Intent Met	Intent met. Remaining mercury switches will not cause spurious suppression system actuations affecting plant equipment.
144	Install additional transfer and isolation switches.	Reduced number of spurious actuations during a fire.	Yes	B - Intent Met	Current fire protection safe shutdown procedures intentionally de-energize circuits to reduce the number of spurious actuations.
145	Enhance fire brigade awareness.	Decreased consequences of a fire.	Yes	B - Intent Met	Fire brigade training and procedures meet current industry practices.
146	Enhance control of combustibles and ignition sources.	Decreased fire frequency and consequences.	Yes	B - Intent Met	Intent met. Procedure exists.
148	Enhance procedures to mitigate large break LOCA.	Reduced consequences of a large break LOCA.	Yes	B - Intent Met	Intent met. Owner's Group recommendations implemented.
149	Install computer aided instrumentation system to assist the operator in assessing post-accident plant status.	Improved prevention of core melt sequences by making operator actions more reliable.	Yes	B - Intent Met	Safety Parameter Display System installed.
150	Improve maintenance procedures.	Improved prevention of core melt sequences by increasing reliability of important equipment.	Yes	B - Intent Met	Intent met. Maintenance procedures are written IAW current industry standards and guidance.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
151	Increase training and operating experience feedback to improve operator response.	Improved likelihood of success of operator actions taken in response to abnormal conditions.	Yes	B - Intent Met	Training and operating experience feedback meets current industry standards and practices.
152	Develop procedures for transportation and nearby facility accidents.	Reduced consequences of transportation and nearby facility accidents.	Yes	B - Intent Met	Intent met but will be reevaluated (nearby industrial facilities) because the potential for impacts of the expanded propane storage facility being modified across the river from BV.
154	Provide Beaver Valley Units 1 and 2 with 4,160 V Bus Crosstie Capability	Adds a success path for blackout on Unit 2 when both Unit 1 diesel generators work, and vice versa	Yes	B - Intent Met	See SAMA #9
156	Operate plant with all PORV block valves open or provide procedures to open block valves when Main Feedwater is lost.	Increased pressure relief capacity to prevent reactor vessel rupture during ATWS.	Yes	B - Intent Met	Intent met. Normal operational alignment has all 3 block valves open. The configuration risk management program limits the amount of time the PORV block valves can remain closed..
157	Loss of Emergency Switchgear Room HVAC , Enhanced Loss of HVAC Procedures	Confidence that operators will prevent thermal damage to switchgear	Yes	B - Intent Met	Intent met. Procedure exists, temporary equipment staged.
158	RCP Seal Cooling for Station Blackout, Potential modifications under review	Reduced frequency of RCP seal LOCA resulting from blackout	Yes	B - Intent Met	Intent met. High temperature seals installed.
160	Pressurizer PORV sticking open after loss of offsite power, Eliminate challenge by defeating the 100% load rejection capability	Reduced frequency of pressurizer PORV sticking open	Yes	B - Intent Met	Turbine trip above 49% power results in a direct reactor trip.
161	Fast 4,160 V Bus Transfer Failure, Explicit Procedure and Training on breaker repair or change out	Reduced frequency that breaker failures will challenge diesel generators	Yes	B - Intent Met	Intent met - Existing procedures implement replacement. Spare breaker internals are available near the required locations.
163	Modify Loss of DC AOP to proceduralize the use of backup battery chargers.	Provide better reliability of the DC busses.	Yes	B - Intent Met	Procedures implemented.
1	Provide additional DC battery capacity.	Extended DC power availability during an SBO.	Yes	C - Combined	Combined with SAMA 3 for methods to extend DC power availability.
2	Replace lead-acid batteries with fuel cells.	Extended DC power availability during an SBO.	Yes	C - Combined	Combined with SAMA 3 for methods to extend DC power availability.
4	Improve DC bus load shedding.	Extended DC power availability during an SBO.	Yes	C - Combined	Combined with SAMA 3 for methods to extend DC power availability.
5	Provide DC bus cross-ties.	Improved availability of DC power system.	Yes	C - Combined	Combined with SAMA 3 for methods to extend DC power availability.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
6	Provide additional DC power to the 120/240V vital AC system.	Increased availability of the 120 V vital AC bus.	Yes	C - Combined	Combined with SAMA 3 for methods to extend DC power availability.
74	Provide hookup for portable generators to power the turbine-driven auxiliary feedwater pump after station batteries are depleted.	Extended auxiliary feedwater availability.	Yes	C - Combined	Combined with SAMA 3 for methods to extend DC power availability.
159	Battery Capacity for steam generator level instruments for station blackout, Enhance procedures on shedding loads or using portable battery chargers. One train of the battery chargers will be powered from the site operable emergency diesel generator once the Station Blackout Unit crosstie modification is complete.	Extended operating time for steam generator level instruments for less of all AC power scenarios	Yes	C - Combined	Combined with SAMA 3 for methods to extend DC power availability.
162	Provide a dedicated diesel driven feed water pump with supply tank to provide an additional source of water for SG tube coverage during SGTR events.	This would eliminate the LERF category and reduce all SGTR events to Small Early Releases.	Yes	C - Combined	Combined with SAMA 78 for installation of dedicated AFW system.
166	Provide additional emergency 125V DC battery capability.	Better coping for long term station blackouts	Yes	C - Combined	Combined with SAMA 3 for methods to extend DC power availability.
24	Bury off-site power lines.	Improved off-site power reliability during severe weather.	Yes	D - Excess Cost	Excessive Implementation Cost
34	Provide an in-containment reactor water storage tank.	Continuous source of water to the safety injection pumps during a LOCA event, since water released from a breach of the primary system collects in the in-containment reactor water storage tank, and thereby eliminates the need to realign the safety injection pumps for long-term post-LOCA recirculation.	Yes	D - Excess Cost	Excessive Implementation Cost
77	Provide a passive, secondary-side heat-rejection loop consisting of a condenser and heat sink.	Reduced potential for core damage due to loss-of-feedwater events.	Yes	D - Excess Cost	Excessive Implementation Cost
90	Create a reactor cavity flooding system.	Enhanced debris cool ability, reduced core concrete interaction, and increased fission product scrubbing.	Yes	D - Excess Cost	Excessive Implementation Cost
91	Install a passive containment spray system.	Improved containment spray capability.	Yes	D - Excess Cost	Excessive Implementation Cost
97	Create a large concrete crucible with heat removal potential to contain molten core debris.	Increased cooling and containment of molten core debris. Molten core debris escaping from the vessel is contained within the crucible and a water cooling mechanism cools the molten core in the crucible, preventing melt-through of the basemat.	Yes	D - Excess Cost	Excessive Implementation Cost
98	Create a core melt source reduction system.	Increased cooling and containment of molten core debris. Refractory material would be placed underneath the reactor vessel such that a molten core falling on the material would melt and combine with the material. Subsequent spreading and heat removal from the vitrified compound would be facilitated, and concrete attack would not occur.	Yes	D - Excess Cost	Excessive Implementation Cost
99	Strengthen primary/secondary containment (e.g., add ribbing to containment shell).	Reduced probability of containment over-pressurization.	Yes	D - Excess Cost	Expert Panel - >MAB
100	Increase depth of the concrete base mat or use an alternate concrete material to ensure melt-through does not occur.	Reduced probability of basemat melt-through.	Yes	D - Excess Cost	Excessive Implementation Cost

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
101	Provide a reactor vessel exterior cooling system.	Increased potential to cool a molten core before it causes vessel failure, by submerging the lower head in water.	Yes	D - Excess Cost	Excessive Implementation Cost
102	Construct a building to be connected to primary/secondary containment and maintained at a vacuum.	Reduced probability of containment over-pressurization.	Yes	D - Excess Cost	Excessive Implementation Cost
110	Erect a barrier that would provide enhanced protection of the containment walls (shell) from ejected core debris following a core melt scenario at high pressure.	Reduced probability of containment failure.	Yes	D - Excess Cost	Excessive Implementation Cost
120	Replace steam generators with a new design.	Reduced frequency of steam generator tube ruptures.	Yes	D - Excess Cost	The cosst to replace the steam generators solely for this SAMA is cost-excessive.
121	Increase the pressure capacity of the secondary side so that a steam generator tube rupture would not cause the relief valves to lift.	Eliminates release pathway to the environment following a steam generator tube rupture.	Yes	D - Excess Cost	Excessive Implementation Cost
122	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture	Enhanced depressurization capabilities during steam generator tube rupture.	Yes	D - Excess Cost	Excessive Implementation Cost
125	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.	Reduced consequences of a steam generator tube rupture.	Yes	D - Excess Cost	Excessive Implementation Cost
126	Install a highly reliable (closed loop) steam generator shell-side heat removal system that relies on natural circulation and stored water sources	Reduced consequences of a steam generator tube rupture.	Yes	D - Excess Cost	Excessive Implementation Cost
129	Vent main steam safety valves in containment.	Reduced consequences of a steam generator tube rupture.	Yes	D - Excess Cost	Excessive Implementation Cost
147	Install digital large break LOCA protection system.	Reduced probability of a large break LOCA (a leak before break).	Yes	D - Excess Cost	Excessive Implementation Cost
3	Add additional battery charger or portable, diesel-driven battery charger to existing DC system.	Improved availability of DC power system.	No		Installed spare battery chargers. Retain for Phase II analysis for evaluation of portable generator.
13	Install an additional, buried off-site power source.	Reduced probability of loss of off-site power.	No		Retain for Phase II analysis.
14	Install a gas turbine generator.	Increased availability of on-site AC power.	No		Retain for Phase II analysis. ERF diesel generator can supply minimal loads
17	Create a cross-tie for diesel fuel oil (multi-unit site).	Increased diesel generator availability.	No		Retain for Phase II analysis.
25	Install an independent active or passive high pressure injection system.	Improved prevention of core melt sequences.	No		Retain for Phase II analysis.
26	Provide an additional high pressure injection pump with independent diesel.	Reduced frequency of core melt from small LOCA and SBO sequences.	No		Retain for Phase II analysis.
28	Add a diverse low pressure injection system.	Improved injection capability.	No		Retain for Phase II analysis.
29	Provide capability for alternate injection via diesel-driven fire pump.	Improved injection capability.	No		Retain for Phase II analysis.
37	Upgrade the chemical and volume control system to mitigate small LOCAs.	For a plant like the Westinghouse AP600, where the chemical and volume control system cannot mitigate a small LOCA, an upgrade would decrease the frequency of core damage.	No		Retain for Phase II analysis.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
39	Replace two of the four electric safety injection pumps with diesel-powered pumps.	Reduced common cause failure of the safety injection system. This SAMA was originally intended for the Westinghouse-CE System 80+, which has four trains of safety injection. However, the intent of this SAMA is to provide diversity within the high- and low-pressure safety injection systems.	No		Retain for Phase II analysis.
41	Create a reactor coolant depressurization system.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	No		Retain for Phase II analysis.
54	Increase charging pump lube oil capacity.	Increased time before charging pump failure due to lube oil overheating in loss of cooling water sequences.	No		Retain for Phase II analysis.
55	Install an independent reactor coolant pump seal injection system, with dedicated diesel.	Reduced frequency of core damage from loss of component cooling water, service water, or station blackout.	No		Retain for Phase II analysis.
56	Install an independent reactor coolant pump seal injection system, without dedicated diesel.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	No		Retain for Phase II analysis.
64	Implement procedure and hardware modifications to allow manual alignment of the fire water system to the component cooling water system, or install a component cooling water header cross-tie.	Improved ability to cool residual heat removal heat exchangers.	No		Retain for Phase II analysis.
65	Install a digital feed water upgrade.	Reduced chance of loss of main feed water following a plant trip.	No		Retain for Phase II analysis. Digital feedwater not installed and not planned.
78	Modify the startup feedwater pump so that it can be used as a backup to the emergency feedwater system, including during a station blackout scenario.	Increased reliability of decay heat removal.	No		Retain for Phase II analysis.
89	Improve SRV and MSIV pneumatic components.	Improved availability of SRVs and MSIVs.	No		Retain for Phase II analysis.
94	Install a filtered containment vent to remove decay heat. Option 1: Gravel Bed Filter; Option 2: Multiple Venturi Scrubber	Increased decay heat removal capability for non-ATWS events, with scrubbing of released fission products.	No		SAMG guidance contains guidance for a number of containment venting paths. Some of these vent paths are filtered. Retain for Phase II analysis.
96	Provide post-accident containment inerting capability.	Reduced likelihood of hydrogen and carbon monoxide gas combustion.	No		Retain for Phase II analysis.
104	Improve leak detection procedures.	Increased piping surveillance to identify leaks prior to complete failure. Improved leak detection would reduce LOCA frequency.	No		Retain for Phase II analysis.
107	Install a redundant containment spray system.	Increased containment heat removal ability.	No		Retain for Phase II analysis.
111	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	Reduced ISLOCA frequency.	No		Retain for Phase II analysis.
112	Add redundant and diverse limit switches to each containment isolation valve.	Reduced frequency of containment isolation failure and ISLOCAs.	No		Retain for Phase II analysis.
113	Increase leak testing of valves in ISLOCA paths.	Reduced ISLOCA frequency.	No		Retain for Phase II analysis.
118	Improve operator training on ISLOCA coping.	Decreased ISLOCA consequences.	No		Retain for Phase II analysis.
119	Institute a maintenance practice to perform a 100% inspection of steam generator tubes during each refueling outage.	Reduced frequency of steam generator tube ruptures.	No		Retain for Phase II analysis.
130	Add an independent boron injection system.	Improved availability of boron injection during ATWS.	No		Retain for Phase II analysis.
131	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	Improved equipment availability after an ATWS.	No		Retain for Phase II analysis.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
133	Install an ATWS sized filtered containment vent to remove decay heat.	Increased ability to remove reactor heat from ATWS events.	No		Retain for Phase II analysis.
136	Install motor generator set trip breakers in control room.	Reduced frequency of core damage due to an ATWS.	No		Retain for Phase II analysis.
137	Provide capability to remove power from the bus powering the control rods.	Decreased time required to insert control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	No		Capability exists outside the control room, but analysis shows the action cannot be taken in the time required. Retain for Phase II analysis.
153	Install secondary side guard pipes up to the main steam isolation valves.	Prevents secondary side depressurization should a steam line break occur upstream of the main steam isolation valves. Also guards against or prevents consequential multiple steam generator tube ruptures following a main steam line break event.	No		Retain for Phase II analysis.
155	Reactor Trip breaker failure , Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	No		Analysis showed that sufficient time is not available to perform this action. PRA updates reduced the importance of this item as a vulnerability. Retain for Phase II analysis.
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	No		Retain for Phase II analysis.
165	Install an independent RCP Seal Injection system.	Reduce frequency of RCP seal failure.	No		Retain for Phase II analysis.
169	Improve operator performance. Operator fails to align makeup to RWST - SGTR, secondary leak	Top 10 operator actions OPRWM1	No		Retain for Phase II analysis.
170	Improve operator performance. Operator fails to manually trip reactor - ATWS	Top 10 operator actions OPROT1	No		Retain for Phase II analysis.
171	Improve operator performance. Operator fails to realign main feedwater - no SI signal	Top 10 operator actions OPROF2	No		Retain for Phase II analysis.
172	Improve operator performance. Operator fails to initiate AFW following transient	Top 10 operator actions OPROS6	No		Retain for Phase II analysis.
173	Improve operator performance. Operator aligns spare battery charger 2-9 to 2-2	Top 10 operator actions OPRDC2	No		Retain for Phase II analysis.
174	Improve operator performance. Operator aligns spare battery charger 2-7 to 2-1	Top 10 operator actions OPRDC1	No		Retain for Phase II analysis.
175	Improve operator performance. Operator fails to initiate bleed and feed	Top 10 operator actions OPROB2	No		Retain for Phase II analysis.
176	Improve operator performance. Operator fails to trip RCP during loss of CCP	Top 10 operator actions OPROC1	No		Retain for Phase II analysis.
177	Improve operator performance. Operator fails to initiate bleed and feed	Top 10 operator actions OPROB1	No		Retain for Phase II analysis.
178	Improve operator performance. Operator fails to identify ruptured SG or initiate isolation	Top 10 operator actions OPRSL1	No		Retain for Phase II analysis.

Table 6-1 BVPS Unit 2 Phase 1 SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	Screened Out Ph I?	Screening Criteria	Phase I Disposition
179	Reduce risk contribution from fires originating in Zone CB-3, causing a total loss of main feedwater and auxiliary feedwater with subsequent failure of feed and bleed.	Elimination or improved mitigation of fires in this area.	No		Retain for Phase II analysis.
180	Reduce risk contribution from fires originating in zone CT-1, causing a total loss of service water.	Elimination or improved mitigation of fires in this area.	No		Retain for Phase II analysis.
181	Reduce risk contribution from fires originating in zone SB-4, causing a total loss of normal AC power with subsequent failure of emergency AC power and station crosstie leading to station blackout.	Elimination or improved mitigation of fires in this area.	No		Retain for Phase II analysis.
183	Reduce risk contribution from fires originating in zone CV-3, causing failure of component cooling water (thermal barrier cooling) and service water with subsequent failure of reactor coolant pump seal injection.	Elimination or improved mitigation of fires in this area.	No		Retain for Phase II analysis.
184	Reduce risk contribution from fires in EDG building, fire initiator DG1L1A.	Elimination or improved mitigation of fires in this area.	No		Retain for Phase II analysis.
185	Reduce risk contribution from fires in EDG building, fire initiator DG2L1A.	Elimination or improved mitigation of fires in this area.	No		Retain for Phase II analysis.
186	Increase seismic ruggedness of the ERF Substation batteries. This refers only to the battery racks, not the entire structure.	Increased reliability of the ERF diesel following seismic events	No		Retain for Phase II analysis.
187	Reduce risk contribution from internal flooding in cable vault area, CV-2 735', by reducing the frequency of the event or by improvements in mitigation of the resulting flooding.	Eliminate or mitigate the consequences of a flood in this area.	No		Retain for Phase II analysis.
188	Reduce risk contribution from internal flooding in Safeguards building, N&S. (Source of flooding is a RWST line.	Eliminate or mitigate the consequences of a flood in this area.	No		Retain for Phase II analysis.
190	Add guidance to the SAMG to consider post-accident cross-tie of the two unit containments through the gaseous waste system.	Reduce or prevent the release of radionuclides as a result of containment failure.	No		Retain for Phase II analysis.

7 PHASE II SAMA ANALYSIS

A cost-benefit analysis was performed on each of the SAMA candidates remaining after the Phase I screening. The benefit of a SAMA candidate is the difference between the baseline cost of severe accident risk (maximum benefit from Section 4.5) and the cost of severe accident risk with the SAMA implemented (Section 7.1). The cost figure used is the estimated cost to implement the specific SAMA. If the estimated cost of implementation exceeds the benefit of implementation, the SAMA is not cost-beneficial.

Since the SAMA analysis is being performed separately for each Beaver Valley unit, the costs and the benefits are provided on a per-unit basis. If a SAMA candidate is shared by the units, that information is noted in the Phase II SAMA candidate list and it is analyzed in a manner consistent with its applicability to both units.

7.1 SAMA BENEFIT

7.1.1 Severe Accident Risk with SAMA Implemented

Bounding analyses were used to determine the change in risk following implementation of SAMA candidates or groups of similar SAMA candidates. For each analysis case, the Level 1 internal events or Level 2 PRA models were altered to conservatively consider implementation of the SAMA candidate(s). Then, severe accident risk measures were calculated using the same procedure used for the baseline case described in Section 3. The changes made to the PRA models for each analysis case are described in Appendix A.

A “bounding analyses” are exemplified by the following:
LBLOCA
This analysis case was used to evaluate the change in plant risk profile that would be achieved if a digital large break LOCA protection system was installed. Although the proposed change would not completely eliminate the potential for a large break LOCA, a bounding benefit was estimated by removing the large break LOCA initiating event. This analysis case was used to model the benefit of SAMA xx.

DCPWR
This analysis case was used to evaluate plant modifications that would increase the availability of Class 1E DC power (e.g., increased battery capacity or the installation of a diesel-powered generator that would effectively increase battery capacity). Although the proposed SAMAs would not completely eliminate the potential failure, a bounding benefit was estimated by removing the

battery discharge events and battery failure events. This analysis case was used to model the benefit of SAMAs a, b, etc.

The severe accident risk measures were obtained for each analysis case by modifying the baseline model in a simple manner to capture the effect of implementation of the SAMA in a bounding manner. Bounding analyses are very conservative and result in overestimation of the benefit of the candidate analyzed. However, if this bounding assessment yields a benefit that is smaller than the cost of implementation, then is it obvious that the effort involved in refining the PRA modeling approach for the SAMA would be unnecessary because it would only yield a lower benefit result. If the benefit is greater than the cost when modeled in this bounding approach, it is necessary to refine the PRA model of the SAMA to remove conservatism. As a result of this modeling approach, models representing the Phase II SAMAs will not all be at the same level of detail and if any are implemented, the PRA result after implementation of the final installed design will differ from the screening-type analyses done during this evaluation.

7.1.2 Cost of Severe Accident Risk with SAMA Implemented

Using the risk measures determined as described in Section 7.1.1, severe accident impacts in four areas (offsite exposure cost, off-site economic cost, on-site exposure cost, and on-site economic cost) were calculated using the same procedure used for the baseline case described in Section 4. As in Section 4.5, the severe accident impacts were summed to estimate the total cost of severe accident risk with the SAMA implemented.

7.1.3 SAMA Benefit Calculation

The respective SAMA benefit was calculated by subtracting the total cost of severe accident risk with the SAMA implemented from the baseline cost of severe accident risk (maximum benefit from Section 4.5). The estimated benefit for each SAMA candidate is listed in Table 7.1. The calculation of the benefit is performed using an Excel spreadsheet.

7.2 COST OF SAMA IMPLEMENTATION

The final step in the evaluation of the SAMAs is estimating the cost of implementation for comparison with the benefit. For the purpose of this analysis the BVNP staff has estimated that the cost of making a change to a procedure and for conducting the necessary training on a procedure change is expected to exceed **$15,000**. Similarly, the minimum cost associated with development and implementation of an integrated hardware modification package (including post-implementation costs, e.g. training) was assumed to be **$100,000**. These values were used for comparison with the benefit of SAMAs.

The benefits resulting from the bounding estimates presented in the benefit analysis are in some cases rather low. In those cases for which the benefits are so low that it is obvious that the implementation costs would exceed the benefit, a detailed cost estimate was not warranted. Plant staff judgment is applied in assessing whether the benefit approaches the expected implementation costs in many cases

Plant staff judgment was obtained from an independent, expert panel consisting of senior staff members from the PRA group, the design group, operations and license renewal. This panel reviewed the benefit calculation results and, based upon their experience with developing and implementing modifications at the plant, judged whether a modification could be made to the plant that would be cost beneficial in comparison with the calculated benefit. The purpose of this approach was to minimize the effort expended on detailed cost estimation. The cost estimations provided by the expert panel are included in Table 7-1 along with the conclusions reached for each SAMA evaluated for cost/benefit.

It should be noted that the results of the sensitivities of Section 8 influenced the decisions of whether a SAMA was considered to be potentially cost beneficial. If the benefits calculated in the sensitivity analyses exceeded the estimated cost of the SAMA, it was considered potentially cost beneficial.

7.3 SAMAs WITH SHARED BENEFIT OR COSTS

A number of SAMAs either benefit both BVPS-1 and BVPS-2 or the cost of implementation would be shared by both units. In this case, consideration of the costs and benefits at only one unit is not appropriate.

SAMA 14, installation of a gas turbine generator, would provide benefit for both units. The maximum combined benefit for this SAMA is $ 1.9 million ($1,495K in Unit 2 and $400K in Unit 1). The cost to implement this SAMA is greater than $7 million. Even with the combined benefit, this SAMA is not cost beneficial.

SAMA 186 (Unit 2) and 187 (Unit 1), increase the seismic ruggedness of the ERF Substation batteries, would provide benefit for both units. Currently the ERF diesel generator can provide power to the Unit 1 Dedicated AFW system, but very little equipment on Unit 2. The benefit of this SAMA to Unit 2 is $3.8K compared to the Unit 1 benefit of $525K. The estimated cost for implementing this SAMA is $300K. This SAMA is considered potentially cost beneficial for BVPS-1, but not for BVPS-2.

SAMA 190 (Unit 2) and 186 (Unit 1) provide a containment cross-tie between the units, would provide benefit to both units. However, the result of using this cross-tie to mitigate an event would result in contamination of both units. The cost of cleanup of the opposite unit is not included in the benefit calculation. Due to the high cost of implementation and the impact on the opposite unit, this SAMA is not considered cost beneficial for either unit.

Unit 1 SAMA 188 (RWST cross-tie) would provide a benefit for both units. However, since the Unit 2 RWST is significantly larger than the Unit 1 RWST, the benefit to Unit 2 would be small and was therefore not considered as a SAMA. The high cost of implementation (>$4,000K), therefore, makes this SAMA not cost beneficial (at either unit).

Table 7-1 BVPS Unit 2 Phase II SAMA Analysis

BV2 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
3	Add additional battery charger or portable, diesel-driven battery charger to existing DC system.	Improved availability of DC power system.	35.42%	29.91%	DC01	Case assumes no failure or depletion of DC power system.	$1,544K	$120K	Expert Panel	Potentially Cost-Beneficial	Potentially cost Beneficial. TDAFW does not require DC power to continue running. This item is to provide portable generator to supply SG level indication.
13	Install an additional, buried off-site power source.	Reduced probability of loss of off-site power.	10.83%	9.96%	NOLOSP	This case was used to determine the benefit of eliminating all loss of offsite power events, both as the initiating event and subsequent to a different initiating event. This allows evaluation of various possible improvements that could reduce the risk associated with loss of offsite power events. For the purposes of the analysis, a single bounding analysis was performed which assumed that loss of offsite power events do not occur, both as an initiating event and subsequent to a different initiating event.	$519K	>$2,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
14	Install a gas turbine generator.	Increased availability of on-site AC power.	35.00%	28.87%	NOSBO	This case is used to determine the benefit of eliminating all Station Blackout events. This allows evaluation of possible improvements related to SBO sequences. For the purpose of the analysis, a single bounding analysis is performed that assumes the Diesel Generators do not fail.	$1,495K	>$7,000K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 14 in Unit 1. See report section 7.3.	Cost Exceeds benefit.
17	Create a cross-tie for diesel fuel oil (multi-unit site).	Increased diesel generator availability.	0.83%	0.70%	SBO1	This case eliminates the failures of the EDGs due to failures in the fuel oil system.	$36.1K	$500K	Expert Panel	Not Cost-Beneficial	No fuel oil cross-tie exists on Unit 2, neither between the Unit 2 trains nor to Unit 1. Implementation would require a modification since there are no existing valves large enough to provide even temporary connection ability. Cost exceeds benefit.
25	Install an independent active or passive high pressure injection system.	Improved prevention of core melt sequences.	0.83%	0.34%	LOCA02	Assume high pressure injection does not fail, works perfectly.	$22.1K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
26	Provide an additional high pressure injection pump with independent diesel.	Reduced frequency of core melt from small LOCA and SBO sequences.	0.83%	0.34%	LOCA02	Assume high pressure injection does not fail, works perfectly.	$22.1K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
28	Add a diverse low pressure injection system.	Improved injection capability.	0.00%	0.03%	LOCA03	Assume low pressure injection system does not fail.	$2.2K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 2 Phase II SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
29	Provide capability for alternate injection via diesel-driven fire pump.	Improved injection capability.	0.00%	0.03%	LOCA03	Assume low pressure injection system does not fail.	$2.2K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
37	Upgrade the chemical and volume control system to mitigate small LOCAs.	For a plant like the Westinghouse AP600, where the chemical and volume control system cannot mitigate a small LOCA, an upgrade would decrease the frequency of core damage.	2.08%	1.57%	LOCA01	Eliminate all small LOCA evens	$83.8K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
39	Replace two of the four electric safety injection pumps with diesel-powered pumps.	Reduced common cause failure of the safety injection system. This SAMA was originally intended for the Westinghouse-CE System 80+, which has four trains of safety injection. However, the intent of this SAMA is to provide diversity within the high- and low-pressure safety injection systems.	0.83%	0.34%	LOCA02	Assume high pressure injection does not fail, works perfectly.	$22.1K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
41	Create a reactor coolant depressurization system.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	2.08%	1.57%	LOCA01	Eliminate all small LOCA evens	$83.8K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
54	Increase charging pump lube oil capacity.	Increased time before charging pump failure due to lube oil overheating in loss of cooling water sequences.	0.00%	0.00%	CHG01	Remove the dependency of the charging pumps on cooling water.	<$1K	>$300K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
55	Install an independent reactor coolant pump seal injection system, with dedicated diesel.	Reduced frequency of core damage from loss of component cooling water, service water, or station blackout.	31.25%	26.32%	RCPLOCA	This case was used to determine the benefit of eliminating all RCP seal LOCA events. This allows evaluation of various possible improvements that could reduce the risk associated with RCP seal LOCA and other small LOCA events.	$1,358K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 2 Phase II SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
56	Install an independent reactor coolant pump seal injection system, without dedicated diesel.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	31.25%	26.32%	RCPLOCA	This case was used to determine the benefit of eliminating all RCP seal LOCA events. This allows evaluation of various possible improvements that could reduce the risk associated with RCP seal LOCA and other small LOCA events.	$1,358K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
64	Implement procedure and hardware modifications to allow manual alignment of the fire water system to the component cooling water system, or install a component cooling water header cross-tie.	Improved ability to cool residual heat removal heat exchangers.	0.00%	0.11%	CCW01	Assume CCW pumps do not failure	$6.0K	$130K	Expert Panel	Not Cost-Beneficial	Hardware modification required as well as procedure changes.
65	Install a digital feed water upgrade.	Reduced chance of loss of main feed water following a plant trip.	0.83%	0.50%	FW01	Eliminate all loss of feedwater initiators.	$27.2K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
78	Modify the startup feedwater pump so that it can be used as a backup to the emergency feedwater system, including during a station blackout scenario.	Increased reliability of decay heat removal.	42.08%	34.99%	DAFW	Unit 2 baseline model with two additions (1) Dedicated AFW (like U1), and (2) portable DC generator for SG level indication power	$1,810K	$3,000K	Expert Panel	Potentially Cost-Beneficial (because the upper bound sensitivity benefit exceeds the cost)	Cost to purchase pump, installation, piping, procedures, etc. to install a dedicated feedwater system similar to Unit 1 and would provide a significant reduction in CDF.
89	Improve SRV and MSIV pneumatic components.	Improved availability of SRVs and MSIVs.	0.00%	0.01%	INSTAIR1	This case was used to determine the benefit of replacing the air compressors. For the purposes of the analysis, a single bounding analysis was performed which assumed the service and instrument air compressors do not fail.	<$1K	>$100K	Expert Panel Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
94	Install a filtered containment vent to remove decay heat. Option 1: Gravel Bed Filter; Option 2: Multiple Venturi Scrubber	Increased decay heat removal capability for non-ATWS events, with scrubbing of released fission products.	0.00%	53.86%	CONT01	Eliminate all failures of containment due to overpressure.	$2,427K	$9,000K	Industry studies (NUREG 1437 supplements) with inflation	Not Cost-Beneficial	Some venting capability currently exists but the post-accident environment could preclude venting. A different vent was considered necessary to assure continued filtering.
96	Provide post-accident containment inerting capability.	Reduced likelihood of hydrogen and carbon monoxide gas combustion.	0.00%	0.45%	H2BURN	Eliminate all Hydrogen detonation.	$25.8K	>$500K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Hydrogen recombiners previously abandoned in place.
104	Improve leak detection procedures.	Increased piping surveillance to identify leaks prior to complete failure. Improved leak detection would reduce LOCA frequency.	0.42%	0.13%	LOCA05	Eliminate all piping failure LOCAs.	$8.5K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Have implemented RI-ISI.
107	Install a redundant containment spray system.	Increased containment heat removal ability.	0.00%	53.86%	CONT01	Eliminate all failures of containment due to overpressure.	$2,427K	>$10,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds the benefit.

Table 7-1 BVPS Unit 2 Phase II SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
111	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	Reduced ISLOCA frequency.	1.25%	2.43%	LOCA06	Eliminate all ISLOCA events	$135K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
112	Add redundant and diverse limit switches to each containment isolation valve.	Reduced frequency of containment isolation failure and ISLOCAs.	0.00%	0.43%	CONT02	Eliminate all containment isolation failures	$20.1K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
113	Increase leak testing of valves in ISLOCA paths.	Reduced ISLOCA frequency.	1.25%	2.43%	LOCA06	Eliminate all ISLOCA events	$135K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Increased outage frequency/duration.
118	Improve operator training on ISLOCA coping.	Decreased ISLOCA consequences.	0.00%	0.01%	LOCA06A	LOCA06 with baseline including optr action to isolate ISLOCA events	<$1K	>$15K	Expert Panel	Not Cost-Beneficial	The PRA case to evaluate the benefit of this SAMA significantly over estimates the benefit. The PRA model does not contain a human error event for failure of the operators to isolate the ISLOCA since the leak pathway contains three check valves, all of which must fail for the ISLOCA to occur. If a human action is credited, the benefit would be extremely small. The results provided are from a sensitivity case comparing the baseline (in which credit is given for break isolation) with the elimination of all ISLOCAs. This is very conservative and still yields extremely small benefits.
119	Institute a maintenance practice to perform a 100% inspection of steam generator tubes during each refueling outage.	Reduced frequency of steam generator tube ruptures.	1.25%	3.02%	NOSGTR	This case was used to determine the benefit of eliminating all SGTR events. This allows evaluation of various possible improvements that could reduce the risk associated with SGTR events. For the purposes of the analysis, a single bounding analysis was performed which assumed that SGTR events do not occur	$165K	>$3,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
130	Add an independent boron injection system.	Improved availability of boron injection during ATWS.	0.42%	0.03%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$4.8K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 2 Phase II SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
131	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	Improved equipment availability after an ATWS.	0.42%	0.03%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$4.8K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
133	Install an ATWS sized filtered containment vent to remove decay heat.	Increased ability to remove reactor heat from ATWS events.	0.42%	0.03%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$4.8K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
136	Install motor generator set trip breakers in control room.	Reduced frequency of core damage due to an ATWS.	0.42%	0.03%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$4.8K	>$100K	Expert Panel Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
137	Provide capability to remove power from the bus powering the control rods.	Decreased time required to insert control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	0.42%	0.03%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$4.8K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
153	Install secondary side guard pipes up to the main steam isolation valves.	Prevents secondary side depressurization should a steam line break occur upstream of the main steam isolation valves. Also guards against or prevents consequential multiple steam generator tube ruptures following a main steam line break event.	0.00%	0.03%	NOSLB	This case was used to determine the benefit of installing secondary side guard pipes up to the MSIVs. This would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. For the purposes of the analysis, a single bounding analysis was performed which assumed that no steam line break events occur.	$1.7K	>$100K	Expert Panel Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.

Table 7-1 BVPS Unit 2 Phase II SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
155	Reactor Trip breaker failure , Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	0.42%	0.03%	NOATWS	This case was used to determine the benefit of eliminating all ATWS events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.	$4.8K	>$100K	Expert Panel Implementation will require plant modification.	Not Cost-Beneficial	Cost exceeds benefit.
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	0.83%	1.48%	SGTR4	Operators close the RCS loop stop valves and gag a stuck-open SV	$86.4K	$50K	Expert Panel	Potentially Cost-Beneficial	SAMA is potentially cost beneficial. Loop stop valves are also not design to close against differential pressure and under accident conditions will not fully seat since hoses must be installed to provide pressure between the seats to fully seat the valve.
165	Install an independent RCP Seal Injection system.	Reduce frequency of RCP seal failure.	31.25%	26.32%	RCPLOCA	This case was used to determine the benefit of eliminating all RCP seal LOCA events. This allows evaluation of various possible improvements that could reduce the risk associated with RCP seal LOCA and other small LOCA events.	$1,358K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
169	Improve operator performance. Operator fails to align makeup to RWST - SGTR, secondary leak	Top 10 operator actions OPRWM1	0.00%	0.20%	HEP1	Reduced the probability of basic event OPRWA1 by a factor of 3.	$10.7K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
170	Improve operator performance. Operator fails to manually trip reactor - ATWS	Top 10 operator actions OPROT1	0.00%	0.01%	HEP2	Reduced the probability of basic event OPRWBV3 by a factor of 3.	<$1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
171	Improve operator performance. Operator fails to realign main feedwater - no SI signal	Top 10 operator actions OPROF2	0.00%	0.26%	HEP3	Reduced the probability of basic event OPROS6 by a factor of 3.	$13.6K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
172	Improve operator performance. Operator fails to initiate AFW following transient	Top 10 operator actions OPROS6	0.83%	0.84%	HEP4	Reduced the probability of basic event OPROB2 by a factor of 3.	$42.6K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
173	Improve operator performance. Operator aligns spare battery charger 2-9 to 2-2	Top 10 operator actions OPRDC2	0.00%	0.10%	HEP5	Reduced the probability of basic event OPRWM1 by a factor of 3.	$5.2K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
174	Improve operator performance. Operator aligns spare battery charger 2-7 to 2-1	Top 10 operator actions OPRDC1	0.00%	0.11%	HEP6	Reduced the probability of basic event OPROC1 by a factor of 3.	$5.5K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
175	Improve operator performance. Operator fails to initiate bleed and feed	Top 10 operator actions OPROB2	1.25%	0.25%	HEP7	Reduced the probability of basic event OPROD2 by a factor of 3.	$20.2K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
176	Improve operator performance. Operator fails to trip RCP during loss of CCP	Top 10 operator actions OPROC1	0.00%	0.12%	HEP8	Reduced the probability of basic event OPROD1 by a factor of 3.	$6.4K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
177	Improve operator performance. Operator fails to initiate bleed and feed	Top 10 operator actions OPROB1	0.00%	0.02%	HEP9	Reduced the probability of basic event OPRCD6 by a factor of 3.	$1.8K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1

Table 7-1 BVPS Unit 2 Phase II SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
178	Improve operator performance. Operator fails to identify ruptured SG or initiate isolation	Top 10 operator actions OPRSL1	0.00%	0.25%	HEP10	Reduced the probability of basic event OPRLR1 by a factor of 3.	$17.6K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
179	Reduce risk contribution from fires originating in Zone CB-3, causing a total loss of main feedwater and auxiliary feedwater with subsequent failure of feed and bleed.	Elimination or improved mitigation of fires in this area.	2.08%	0.44%	FIRE05	This case eliminates the fires in zone CB-3 that cause a total loss of main feedwater and auxiliary feedwater with subsequent failure of bleed and feed.	$34.4K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
180	Reduce risk contribution from fires originating in zone CT-1, causing a total loss of service water.	Elimination or improved mitigation of fires in this area.	4.58%	3.92%	FIRE06	This case eliminates the fires in zone CT-1 that cause a total loss of service water.	$202K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
181	Reduce risk contribution from fires originating in zone SB-4, causing a total loss of normal AC power with subsequent failure of emergency AC power and station crosstie leading to station blackout.	Elimination or improved mitigation of fires in this area.	0.00%	0.21%	FIRE07	This case eliminates the fires in zone SB-4 that cause a total loss of normal AC power with subsequent failure of emergency AC power and station crosstie leading to station blackout.	$10.7K	$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
183	Reduce risk contribution from fires originating in zone CV-3, causing failure of component cooling water (thermal barrier cooling) and service water with subsequent failure of reactor coolant pump seal injection.	Elimination or improved mitigation of fires in this area.	1.25%	1.03%	FIRE09	This case eliminates the fires in zone CV-3 that cause failure of component cooling water (thermal barrier cooling) and service water with subsequent failure of reactor coolant pump seal injection.	$54.6K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
184	Reduce risk contribution from fires in EDG building, fire initiator DG1L1A.	Elimination or improved mitigation of fires in this area.	3.75%	3.18%	FIRE10	This case eliminates the fires in zone DG1L1A, Emergency Diesel Generator (EDG) building.	$164K	$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.. This represents 1/2 the cost; remainder associated with SAMA 185.
185	Reduce risk contribution from fires in EDG building, fire initiator DG2L1A.	Elimination or improved mitigation of fires in this area.	3.75%	3.17%	FIRE11	This case eliminates the fires in zone DG2L1A, EDG building.	$163K	$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. This represents 1/2 the cost; remainder associated with SAMA 184.
186	Increase seismic ruggedness of the ERF Substation batteries. This refers only to the battery racks, not the entire structure.	Increased reliability of the ERF diesel following seismic events	0.00%	0.07%	SEISMIC1	This case assumes a seismic ruggedness for the ERF Substation battery that is the same as that for the station batteries.	$3.8K	$300K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 187 in Unit 1. See report section 7.3.	Unit 1 benefit - Reference U1 SAMA 187

Table 7-1 BVPS Unit 2 Phase II SAMA Analysis (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	% Red. In CDF	% Red. In OS Dose	SAMA Case	SAMA Case Description	Benefit	Cost	Cost Basis	Evaluation	Basis for Evaluation
187	Reduce risk contribution from internal flooding in cable vault area, CV-2 735', by reducing the frequency of the event or by improvements in mitigation of the resulting flooding.	Eliminate or mitigate the consequences of a flood in this area.	0.00%	0.00%	FLOOD1D	FLOOD1 with the operators failing to isolate the leakage from the fire water pipe	<$1K	>$15K	Expert Panel	Not Cost-Beneficial	Source of flooding is a 4" fire water pipe that traverses the area. The PRA currently does not include credit for the procedure that is in place to isolate a leak/break in the subject piping; i.e., the PRA model does not contain the human error event for failure of the operators to isolate the flood source. If the human action is credited, the benefit for improvements in mitigate would be extremely small. The results provided are from a sensitivity case comparing a revised baseline (in which credit is given for break isolation) (FLOOD1D) with the elimination of this internal flooding scenario. This is very conservative and still yields extremely small benefits; no change in procedures or hardware would be cost-beneficial.
188	Reduce risk contribution from internal flooding in Safeguards building, N&S. (Source of flooding is a RWST line.	Eliminate or mitigate the consequences of a flood in this area.	1.25%	1.23%	FLOOD2	This case eliminates the safeguards building N&S rooms internal flood.	$63.4K	>$200K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
190	Add guidance to the SAMG to consider post-accident cross-tie of the two unit containments through the gaseous waste system.	Reduce or prevent the release of radionuclides as a result of containment failure.	0.00%	53.86%	CONT01	Eliminate all failures of containment due to overpressure.	$2,427K	>$10,000K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 186 in Unit 1. See report section 7.3.	Cost will exceed benefit due to cleanup costs and replacement power at opposite unit.

Note 1 – The current plant procedures and training meet current industry standards. The benefit calculation results provided in this table are based upon an arbitrary reduction in HEP of a factor of 3 and are provided solely to demonstrate the sensitivity of the model to change in the HEP. There are no additional specific procedure improvements that could be identified that would affect the result of the HEP calculations to this level of reduction. Therefore, it is expected that the idealistic benefits presented in the table are not achievable with procedure improvements only and would require additional hardware modifications. In all cases the costs of hardware and procedure changes would exceed the idealistic benefits presented in the table. These SAMAs are, therefore, screened as Not Cost Beneficial.

8 SENSITIVITY ANALYSES

The purpose of performing sensitivity analyses is to examine the impact of analysis assumptions on the results of the SAMA evaluation. This section identifies several sensitivities that can be performed during SAMA (Reference 24) and discusses the sensitivity as is applies to Beaver Valley Unit 2 and the impact of the sensitivity on the results of the Phase II SAMA analysis at BVPS-2.

Unless it was otherwise noted, it is assumed in these sensitivity analyses that sufficient margin existed in the maximum benefit estimation that the Phase I screening would not have to be repeated in the sensitivity analyses.

8.1 PLANT MODIFICATIONS

There are no plant modifications that are currently pending that would be expected to impact the results of this SAMA evaluation.

8.2 UNCERTAINTY

Since the inputs to PRA cannot be known with complete certainty, there is possibility that the actual plant risk is greater than the mean values used in the evaluation of the SAMA described in the previous sections. To consider this uncertainty, a sensitivity analysis was performed in which an uncertainty factor was applied to the frequencies calculated by the PRA and the subsequent benefits were calculated based upon the mean risk values multiplied by this uncertainty factor. The uncertainty factor applied is the ratio of the 95th percentile value of the CDF from the PRA uncertainty analysis to the mean value of the CDF. For Unit 2 the 95th percentile value of the CDF is 3.89E-5/yr; therefore, uncertainty factor is 1.62. Table 8-1 provides the benefit results from each of the sensitivities for each of the SAMA cases evaluated.

8.3 PEER REVIEW FACTS/OBSERVATIONS

The model used in this SAMA analysis includes the resolution of the Facts-and-Observations (F&Os) identified during the PRA Peer Review. Therefore, no specific sensitivities were performed related to this issue.

8.4 EVACUATION SPEED

Three evacuation sensitivity cases were performed to determine the impact of evacuation assumptions. One sensitivity case reduced the evacuation speed by a factor of four (0.05 m/sec) and the second increased the speed to 2.24 m/s. The third sensitivity case assumed an increase by a factor of 1.5 in the alarm time, thus delaying the commencement of physical evacuation.

The base evacuation speed was derived in a conservative manner assuming inclement weather and persons without transportation an average evacuation speed of 0.2 m/s was determined. A decrease in the evacuation speed by a factor of four to 0.05 m/s would have the impact of taking over 2 days to evacuate. Runs with an increase to 2.24 m/s (approximately 5 mph) were also performed to assess the slope and relative sensitivity of the dose to evacuation speed.

The third sensitivity case performed was a delay in the alarm time to simulate problems in communication that might be experienced during the night or severe weather. The alarm delay was multiplied by a factor of 1.5 for this case.

The results of the evacuation sensitivity runs indicated that Mean Total Economic Costs are very insensitive to evacuations speeds. Decreasing the evacuation speed had a maximum impact of 10 percent on total dose. Total dose was not sensitive to a delay on the alarm time. The Mean Population Exceeding 0.05 Sv showed some sensitivity to evacuation speed for the late containment failures. The tables below provide a summary of the evacuation sensitivity results.

Table 8.4-1 Evacuation Speed Sensitivity Results

Release Category	Base Note 1	Evacuation Speed				Alarm Delay	
		Slower (0.11 mph	Percent Change	Faster (5 mph)	Percent Change	1.5 x OALARM	Percent Change
Mean L-EFFECTIVE TOT LIF Dose (Sv)							
INTACT	8	8	1	8	-3	8	0
ECF							
VSEQ	50,400	53,700	7	42,700	-15	50,100	-1
SGTR	44,500	47,400	7	40,500	-9	44,700	0
DCH	86,800	88,900	2	81,500	-6	86,800	0
SECF							
SGTR	50,500	55,500	10	29,000	-43	50,500	0
LOCI	35,200	37,200	6	31,700	-10	35,300	0
BV5	43,800	46,400	6	34,600	-21	44,200	1
LATE							
Large	1,530	1,540	1	1,470	-4	1,540	1
Small	20,200	21,400	6	20,200	0	20,300	0
H2 Burn	19,300	19,900	3	18,700	-3	19,400	1
BMMT	7,680	7,850	2	7,670	0	7,680	0
Mean Population Exceeding 0.05 Sv							
INTACT	0	0	0	0	0	0	0
ECF							
VSEQ	143,000	143,000	0	138,000	-3	143,000	0
SGTR	154,000	154,000	0	147,000	-5	154,000	0
DCH	274,000	275,000	0	266,000	-3	274,000	0
SECF							
SGTR	80,200	80,700	1	72,400	-10	80,200	0
LOCI	37,600	38,400	2	28,300	-25	37,400	-1
BV5	86,700	87,200	1	80,100	-8	86,900	0
LATE							
Large	2	27	1,499	2	-8	3	62
Small	7,170	12,900	80	7,150	0	7,240	1
H2 Burn	21,700	24,700	14	18,500	-15	23,000	6
BMMT	2,210	2,730	24	2,200	0	2,240	1
Mean Total Economic Costs ($)							
INTACT	6.400E+03	6.400E+03	0	6.400E+03	0	6.400E+03	0
ECF							
VSEQ	3.530E+10	3.530E+10	0	3.530E+10	0	3.530E+10	0
SGTR	4.280E+10	4.280E+10	0	4.280E+10	0	4.280E+10	0
DCH	4.800E+10	4.800E+10	0	4.800E+10	0	4.800E+10	0
SECF							
SGTR	2.540E+10	2.540E+10	0	2.540E+10	0	2.540E+10	0
LOCI	2.650E+10	2.650E+10	0	2.650E+10	0	2.650E+10	0
BV5	1.130E+10	1.130E+10	0	1.130E+10	0	1.130E+10	0
LATE							
Large	1.180E+08	1.180E+08	0	1.180E+08	0	1.180E+08	0
Small	1.090E+10	1.090E+10	0	1.090E+10	0	1.090E+10	0
H2 Burn	6.670E+09	6.670E+09	0	6.670E+09	0	6.670E+09	0
BMMT	4.380E+09	4.380E+09	0	4.380E+09	0	4.380E+09	0

Note 1 Current Economic data, 2047 population data, and 2001 met data

8.5 REAL DISCOUNT RATE

Calculation of severe accident impacts in the BVPS-2 SAMA analysis was performed using a "real discount rate" of 7% (0.07/year) as recommended in Reference 20. Use of both a 7% and 3% real discount rate in regulatory analysis is specified in Office of Management Budget (OMB) guidance (Reference 25) and in NUREG/BR-0058 (Reference 26). Therefore, a sensitivity analysis was performed using a 3% real discount rate.

In this sensitivity analysis, the real discount rate in the Level 3 PRA model was changed to 3% from 7% and the Phase II analysis was re-performed with the lower interest rate.

The results of this sensitivity analysis are presented in Table 8-1. This sensitivity analysis does not challenge any decisions made regarding the SAMAs.

8.6 ANALYSIS PERIOD

As described in Section 4, calculation of severe accident impacts involves an analysis period term, t_f, which could have been defined as either the period of extended operation (20 years), or the years remaining until the end of facility life (from the time of the SAMA analysis to the end of the period of extended operation) (40 years for Unit 2).

The value used for this term was the period of extended operation (20 years). This sensitivity analysis was performed using the period from the time of the SAMA analysis to the end of the period of extended operation to determine if SAMAs would be potentially cost-beneficial if performed immediately.

In this sensitivity analysis, the analysis period in the calculation of severe accident risk was modified to 40 years and the Phase II analysis was re-performed with the revised analysis period. The cost of additional years of maintenance, surveillance, calibrations, and training were included appropriately in the cost estimates for SAMAs in this Phase II analysis.

The results of this sensitivity analysis are presented in Table 8-1. This sensitivity analysis does not challenge any decisions made regarding the SAMAs.

Table 8-1 BVPS Unit 2 SAMA Sensitivity Evaluation

BV2 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
3	Add additional battery charger or portable, diesel-driven battery charger to existing DC system.	Improved availability of DC power system.	DC01	$1,544K	$2,227K	$1,378K	$2,009K	$2,966K	$120K	Expert Panel	Potentially Cost-Beneficial	Potentially cost Beneficial. TDAFW does not require DC power to continue running. This item is to provide portable generator to supply SG level indication.
13	Install an additional, buried off-site power source.	Reduced probability of loss of off-site power.	NOLOSP	$519K	$746K	$463K	$673K	$1,000K	>$2,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
14	Install a gas turbine generator.	Increased availability of on-site AC power.	NOSBO	$1,495K	$2,158K	$1,334K	$1,947K	$2,869K	>$7,000K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 14 in Unit 1. See report section 7.3.	Cost Exceeds benefit.
17	Create a cross-tie for diesel fuel oil (multi-unit site).	Increased diesel generator availability.	SBO1	$36.1K	$52.0K	$32.2K	$47.0K	$69.2K	$500K	Expert Panel	Not Cost-Beneficial	No fuel oil cross-tie exists on Unit 2, neither between the Unit 2 trains nor to Unit 1. Implementation would require a modification since there are no existing valves large enough to provide even temporary connection ability. Cost exceeds benefit.
25	Install an independent active or passive high pressure injection system.	Improved prevention of core melt sequences.	LOCA02	$22.1K	$32.8K	$19.6K	$29.8K	$40.3K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
26	Provide an additional high pressure injection pump with independent diesel.	Reduced frequency of core melt from small LOCA and SBO sequences.	LOCA02	$22.1K	$32.8K	$19.6K	$29.8K	$40.3K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
28	Add a diverse low pressure injection system.	Improved injection capability.	LOCA03	$2.2K	$3.4K	$1.9K	$3.2K	$3.6K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
29	Provide capability for alternate injection via diesel-driven fire pump.	Improved injection capability.	LOCA03	$2.2K	$3.4K	$1.9K	$3.2K	$3.6K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
37	Upgrade the chemical and volume control system to mitigate small LOCAs.	For a plant like the Westinghouse AP600, where the chemical and volume control system cannot mitigate a small LOCA, an upgrade would decrease the frequency of core damage.	LOCA01	$83.8K	$122K	$74.6K	$110K	$159K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
39	Replace two of the four electric safety injection pumps with diesel-powered pumps.	Reduced common cause failure of the safety injection system. This SAMA was originally intended for the Westinghouse-CE System 80+, which has four trains of safety injection. However, the intent of this SAMA is to provide diversity within the high- and low-pressure safety injection systems.	LOCA02	$22.1K	$32.8K	$19.6K	$29.8K	$40.3K	>$100K	Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
41	Create a reactor coolant depressurization system.	Allows low pressure emergency core cooling system injection in the event of small LOCA and high-pressure safety injection failure.	LOCA01	$83.8K	$122K	$74.6K	$110K	$159K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.

Table 8-1 BVPS Unit 2 SAMA Sensitivity Evaluation (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
54	Increase charging pump lube oil capacity.	Increased time before charging pump failure due to lube oil overheating in loss of cooling water sequences.	CHG01	<$1K	<$1K	<$1K	<$1K	<$1K	>$300K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
55	Install an independent reactor coolant pump seal injection system, with dedicated diesel.	Reduced frequency of core damage from loss of component cooling water, service water, or station blackout.	RCPLOCA	$1,358K	$1,959K	$1,212K	$1,768K	$2,607K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
56	Install an independent reactor coolant pump seal injection system, without dedicated diesel.	Reduced frequency of core damage from loss of component cooling water or service water, but not a station blackout.	RCPLOCA	$1,358K	$1,959K	$1,212K	$1,768K	$2,607K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
64	Implement procedure and hardware modifications to allow manual alignment of the fire water system to the component cooling water system, or install a component cooling water header cross-tie.	Improved ability to cool residual heat removal heat exchangers.	CCW01	$6.0K	$8.7K	$5.4K	$7.9K	$11.4K	$130K	Expert Panel	Not Cost-Beneficial	Hardware modification required as well as procedure changes.
65	Install a digital feed water upgrade.	Reduced chance of loss of main feed water following a plant trip.	FW01	$27.2K	$39.8K	$24.2K	$36.1K	$50.9K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
78	Modify the startup feedwater pump so that it can be used as a backup to the emergency feedwater system, including during a station blackout scenario.	Increased reliability of decay heat removal.	DAFW	$1,810K	$2,612K	$1,615K	$2,358K	$3,474K	$3,000K	Expert Panel	Potentially Cost-Beneficial (because the upper bound sensitivity benefit exceeds the cost)	Cost to purchase pump, installation, piping, procedures, etc. to install a dedicated feedwater system similar to Unit 1 and would provide a significant reduction in CDF.
89	Improve SRV and MSIV pneumatic components.	Improved availability of SRVs and MSIVs.	INSTAIR1	<$1K	<$1K	<$1K	<$1K	<$1K	>$100K	Expert Panel Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
94	Install a filtered containment vent to remove decay heat. Option 1: Gravel Bed Filter; Option 2: Multiple Venturi Scrubber	Increased decay heat removal capability for non-ATWS events, with scrubbing of released fission products.	CONT01	$2,427K	$3,392K	$2,189K	$3,026K	$4,948K	$9,000K	Industry studies (NUREG 1437 supplements) with inflation	Not Cost-Beneficial	Some venting capability currently exists but the post-accident environment could preclude venting. A different vent was considered necessary to assure continued filtering.
96	Provide post-accident containment inerting capability.	Reduced likelihood of hydrogen and carbon monoxide gas combustion.	H2BURN	$25.8K	$36.1K	$23.3K	$32.2K	$52.7K	>$500K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Hydrogen recombiners previously abandoned in place.
104	Improve leak detection procedures.	Increased piping surveillance to identify leaks prior to complete failure. Improved leak detection would reduce LOCA frequency.	LOCA05	$8.5K	$12.9K	$7.4K	$11.8K	$14.7K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Have implemented RI-ISI.
107	Install a redundant containment spray system.	Increased containment heat removal ability.	CONT01	$2,428K	$3,392K	$2,189K	$3,026K	$4,948K	>$10,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds the benefit.
111	Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	Reduced ISLOCA frequency.	LOCA06	$135K	$191K	$121K	$171K	$269K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
112	Add redundant and diverse limit switches to each containment isolation valve.	Reduced frequency of containment isolation failure and ISLOCAs.	CONT02	$20.1K	$28.6K	$18.0K	$25.7K	$39.6K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.

Table 8-1 BVPS Unit 2 SAMA Sensitivity Evaluation (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
113	Increase leak testing of valves in ISLOCA paths.	Reduced ISLOCA frequency.	LOCA06	$135K	$191K	$121K	$171K	$269K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. Increased outage frequency/duration.
118	Improve operator training on ISLOCA coping.	Decreased ISLOCA consequences.	LOCA06A	<$1K	<$1K	<$1K	<$1K	<$1K	>$15K	Expert Panel	Not Cost-Beneficial	The PRA case to evaluate the benefit of this SAMA significantly over estimates the benefit. The PRA model does not contain a human error event for failure of the operators to isolate the ISLOCA since the leak pathway contains three check valves, all of which must fail for the ISLOCA to occur. If a human action is credited, the benefit would be extremely small. The results provided are from a sensitivity case comparing the baseline (in which credit is given for break isolation) with the elimination of all ISLOCAs. This is very conservative and still yields extremely small benefits.
119	Institute a maintenance practice to perform a 100% inspection of steam generator tubes during each refueling outage.	Reduced frequency of steam generator tube ruptures.	NOSGTR	$165K	$234K	$149K	$210K	$329K	>$3,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
130	Add an independent boron injection system.	Improved availability of boron injection during ATWS.	NOATWS	$4.8K	$8.0K	$4.1K	$7.5K	$6.4K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
131	Add a system of relief valves to prevent equipment damage from pressure spikes during an ATWS.	Improved equipment availability after an ATWS.	NOATWS	$4.8K	$8.0K	$4.1K	$7.5K	$6.4K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
133	Install an ATWS sized filtered containment vent to remove decay heat.	Increased ability to remove reactor heat from ATWS events.	NOATWS	$4.8K	$8.0K	$4.1K	$7.5K	$6.4K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
136	Install motor generator set trip breakers in control room.	Reduced frequency of core damage due to an ATWS.	NOATWS	$4.8K	$8.0K	$4.1K	$7.5K	$6.4K	>$100K	Expert Panel Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
137	Provide capability to remove power from the bus powering the control rods.	Decreased time required to insert control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	NOATWS	$4.8K	$8.0K	$4.1K	$7.5K	$6.4K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.

Table 8-1 BVPS Unit 2 SAMA Sensitivity Evaluation (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
153	Install secondary side guard pipes up to the main steam isolation valves.	Prevents secondary side depressurization should a steam line break occur upstream of the main steam isolation valves. Also guards against or prevents consequential multiple steam generator tube ruptures following a main steam line break event.	NOSLB	$1.7K	$2.4K	$1.5K	$2.2K	$3.1K	>$100K	Expert Panel Screening Hardware Change Value	Not Cost-Beneficial	Cost exceeds benefit.
155	Reactor Trip breaker failure , Enhance Procedures for removing power from the bus	Enhanced recovery potential for rapid pressure spikes (~ 1 to 2 minutes) during ATWS.	NOATWS	$4.8K	$8.0K	$4.1K	$7.5K	$6.4K	>$100K	Expert Panel Implementation will require plant modification.	Not Cost-Beneficial	Cost exceeds benefit.
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	SGTR4	$86.4K	$122K	$77.6K	$109K	$172K	$50K	Expert Panel	Potentially Cost-Beneficial	SAMA is potentially cost beneficial. Loop stop valves are also not design to close against differential pressure and under accident conditions will not fully seat since hoses must be installed to provide pressure between the seats to fully seat the valve.
165	Install an independent RCP Seal Injection system.	Reduce frequency of RCP seal failure.	RCPLOCA	$1,358K	$1,959K	$1,212K	$1,768K	$2,607K	>$4,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
169	Improve operator performance. Operator fails to align makeup to RWST - SGTR, secondary leak	Top 10 operator actions OPRWM1	HEP1	$10.7K	$15.1K	$9.6K	$13.5K	$21.3K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
170	Improve operator performance. Operator fails to manually trip reactor - ATWS	Top 10 operator actions OPROT1	HEP2	<$1K	$1.5K	<$1K	$1.4K	$1.7K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
171	Improve operator performance. Operator fails to realign main feedwater - no SI signal	Top 10 operator actions OPROF2	HEP3	$13.6K	$19.6K	$12.2K	$17.7K	$26.2K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
172	Improve operator performance. Operator fails to initiate AFW following transient	Top 10 operator actions OPROS6	HEP4	$42.6K	$61.2K	$38.0K	$55.2K	$82.3K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
173	Improve operator performance. Operator aligns spare battery charger 2-9 to 2-2	Top 10 operator actions OPRDC2	HEP5	$5.2K	$7.6K	$4.7K	$6.8K	$10.1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
174	Improve operator performance. Operator aligns spare battery charger 2-7 to 2-1	Top 10 operator actions OPRDC1	HEP6	$5.5K	$8.0K	$4.9K	$7.2K	$10.6K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
175	Improve operator performance. Operator fails to initiate bleed and feed	Top 10 operator actions OPROB2	HEP7	$20.2K	$30.6K	$17.8K	$28.1K	$35.1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
176	Improve operator performance. Operator fails to trip RCP during loss of CCP	Top 10 operator actions OPROC1	HEP8	$6.4K	$9.3K	$5.7K	$8.5K	$12.1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1

Table 8-1 BVPS Unit 2 SAMA Sensitivity Evaluation (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
177	Improve operator performance. Operator fails to initiate bleed and feed	Top 10 operator actions OPROB1	HEP9	$1.8K	$2.7K	$1.6K	$2.5K	$3.2K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
178	Improve operator performance. Operator fails to identify ruptured SG or initiate isolation	Top 10 operator actions OPRSL1	HEP10	$17.6K	$24.8K	$15.8K	$22.2K	$35.1K	See Note 1.	See Note 1.	Not Cost-Beneficial	See Note 1
179	Reduce risk contribution from fires originating in Zone CB-3, causing a total loss of main feedwater and auxiliary feedwater with subsequent failure of feed and bleed.	Elimination or improved mitigation of fires in this area.	FIRE05	$34.4K	$52.1K	$30.2K	$47.8K	$59.8K	>$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
180	Reduce risk contribution from fires originating in zone CT-1, causing a total loss of service water.	Elimination or improved mitigation of fires in this area.	FIRE06	$202K	$292K	$181K	$264K	$389K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
181	Reduce risk contribution from fires originating in zone SB-4, causing a total loss of normal AC power with subsequent failure of emergency AC power and station crosstie leading to station blackout.	Elimination or improved mitigation of fires in this area.	FIRE07	$10.7K	$15.4K	$9.5K	$13.9K	$20.5K	$100K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
183	Reduce risk contribution from fires originating in zone CV-3, causing failure of component cooling water (thermal barrier cooling) and service water with subsequent failure of reactor coolant pump seal injection.	Elimination or improved mitigation of fires in this area.	FIRE09	$54.6K	$79.2K	$48.7K	$71.6K	$104K	>$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit
184	Reduce risk contribution from fires in EDG building, fire initiator DG1L1A.	Elimination or improved mitigation of fires in this area.	FIRE10	$164K	$237K	$147K	$214K	$316K	$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.. This represents 1/2 the cost; remainder associated with SAMA 185.
185	Reduce risk contribution from fires in EDG building, fire initiator DG2L1A.	Elimination or improved mitigation of fires in this area.	FIRE11	$163K	$236K	$146K	$213K	$314K	$1,000K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit. This represents 1/2 the cost; remainder associated with SAMA 184.
186	Increase seismic ruggedness of the ERF Substation batteries. This refers only to the battery racks, not the entire structure.	Increased reliability of the ERF diesel following seismic events	SEISMIC1	$3.8K	$5.5K	$3.4K	$5.0K	$7.3K	$300K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 187 in Unit 1. See report section 7.3.	Unit 1 benefit - Reference U1 SAMA 187

Table 8-1 BVPS Unit 2 SAMA Sensitivity Evaluation (Cont.)

BV2 SAMA Number	Potential Improvement	Discussion	SAMA Case	Benefit	Benefit at 3% Disc Rate	Benefit at BE Disc Rate	Benefit at 25yrs	Benefit at UB	Cost	Cost Basis	Evaluation	Basis for Evaluation
187	Reduce risk contribution from internal flooding in cable vault area, CV-2 735', by reducing the frequency of the event or by improvements in mitigation of the resulting flooding.	Eliminate or mitigate the consequences of a flood in this area.	FLOOD1D	<$1K	<$1K	<$1K	<$1K	<$1K	>$15K	Expert Panel	Not Cost-Beneficial	Source of flooding is a 4" fire water pipe that traverses the area. The PRA currently does not include credit for the procedure that is in place to isolate a leak/break in the subject piping; i.e., the PRA model does not contain the human error event for failure of the operators to isolate the flood source. If the human action is credited, the benefit for improvements in mitigate would be extremely small. The results provided are from a sensitivity case comparing a revised baseline (in which credit is given for break isolation) (FLOOD1D) with the elimination of this internal flooding scenario. This is very conservative and still yields extremely small benefits; no change in procedures or hardware would be cost-beneficial.
188	Reduce risk contribution from internal flooding in Safeguards building, N&S. (Source of flooding is a RWST line.	Eliminate or mitigate the consequences of a flood in this area.	FLOOD2	$63.4K	$91.5K	$56.6K	$82.6K	$122K	>$200K	Expert Panel	Not Cost-Beneficial	Cost exceeds benefit.
190	Add guidance to the SAMG to consider post-accident cross-tie of the two unit containments through the gaseous waste system.	Reduce or prevent the release of radionuclides as a result of containment failure.	CONT01	$2,427K	$3,392K	$2,189K	$3,026K	$4,948K	>$10,000K	Expert Panel	Not Cost-Beneficial. This SAMA affects both units; see SAMA 186 in Unit 1. See report section 7.3.	Cost will exceed benefit due to cleanup costs and replacement power at opposite unit.

Note 1 – The current plant procedures and training meet current industry standards. The benefit calculation results provided in this table are based upon an arbitrary reduction in HEP of a factor of 3 and are provided solely to demonstrate the sensitivity of the model to change in the HEP. There are no additional specific procedure improvements that could be identified that would affect the result of the HEP calculations to this level of reduction. Therefore, it is expected that the idealistic benefits presented in the table are not achievable with procedure improvements only and would require additional hardware modifications. In all cases the costs of hardware and procedure changes would exceed the idealistic benefits presented in the table. These SAMAs are, therefore, screened as Not Cost Beneficial.

9 CONCLUSIONS

As a result of this analysis, the SAMAs identified in Table 9-1 have been identified as potentially cost beneficial, either directly or as a result of the sensitivity analyses. However, since the other potential improvements could result in a reduction in public risk, these SAMAs will be entered into the Beaver Valley Long-range Plan development process for further consideration.

Implementation of SAMA 3 would involve the purchase of a portable generator to supply power to the steam generator level instrumentation. The TDAFW pump does not require power to start or continue running.

Implementation of SAMA 78 would require removing the start-up feedwater pump skid (including main motor and associated auxiliary oil and seal water pumps and motors), and associated suction, discharge and recirculation piping and valves (including the current motor-operated and air-operated discharge valves). These components would be replaced by a smaller pump and motor skid, and associated piping and valves. The new suction and recirculation piping and valves would be run to an independent water source outside of the Turbine Building. The new discharge piping and valves (including a new motor-operated discharge valve), would be run to the abandoned location on the main feedwater header. Any disconnected, original power and control cabling (and associated circuit breakers, control switches and alarms) from the ERF substation and Unit 2 Control Room would be reused where possible.

Implementation of SAMA 164 would involve two actions. The first is a procedural change to direct the operators to close the RCS loop stop valves to isolate a steam generator that has had a tube failure. The second involves purchase or manufacture of a gagging device that could be used to close a stuck open steam generator safety valve (i.e., faulted) on the ruptured steam generator prior to core damage in SGTR events.

None of the SAMAs in Table 9-1 have been found to be aging-related.

Table 9-1 BVPS-2 Potentially Cost Beneficial SAMAs

BV2 SAMA Number	Potential Improvement	Discussion	Additional Discussion
3	Add additional battery charger or portable, diesel-driven battery charger to existing DC system.	Improved availability of DC power system.	
78	Modify the startup feedwater pump so that it can be used as a backup to the emergency feedwater system, including during a station blackout scenario.	Increased reliability of decay heat removal.	This would provide a system similar to the dedicated AFW pump present at Unit 1.
164	Modify emergency procedures to isolate a faulted ruptured SG due to a stuck open safety valve. This SAMA to provide procedural guidance to close the RCS loop stop valve to isolate the generator from the core and provide mechanical device to close a stuck open SG safety valve.	Reduce release due to SGTR.	

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APPENDIX A – PRA RUNS FOR SELECTED SAMA CASES

Explanation of Appendix A Contents

This appendix describes each of the SAMA evaluation cases. An evaluation case is an evaluation of plant risk using a plant PRA model that considers implementation of the evaluated SAMA. The case-specific plant configuration is defined as the plant in its baseline configuration with the model modified to represent the plant after the implementation of a particular SAMA. As indicated in the main report, these model changes were performed in a manner expected to bound the change in risk that would actually be expected if the SAMA were implemented. This approach was taken because the actual designs for the SAMAs have not been developed.

Each analysis case is described in the following pages. Each case description contains a description of the physical change that the case represents along with a description of the SAMAs that are being evaluated by this specific case.

The PDS frequencies calculated as a result of the PRA model quantification for each SAMA case is presented in Table A-5.

Case INSTAIR1

Description: This case is used to determine the benefit of replacing the air compressors. For the purposes of the analysis, a single bounding condition was performed, which assumed the station instrument air system does not fail.

Case NOATWS

Description: This case is used to determine the benefit of eliminating all Anticipated Transient Without Scram (ATWS) events. For the purposes of the analysis, a single bounding analysis was performed which assumed that ATWS events do not occur.

Case NOSGTR

Description: This case is used to determine the benefit of eliminating all steam generator tube rupture (SGTR) events. This allows evaluation of various possible improvements that could reduce the risk associated with SGTR events. For the purposes of this analysis, a single bounding analysis was performed which assumed that SGTR events do not occur.

Case NOLOSP

Description: This case is used to determine the benefit of eliminating all loss of offsite power (LOSP) events, both as the initiating event and subsequent to a different initiating event. This allows evaluation of various possible improvements that could reduce the risk associated with LOSP events. For the purposes of the analysis, a single bounding analysis was performed which assumed that LOSP events do not occur, both as an initiating event and subsequent to a different initiating event.

Case NOSBO

Description: This case is used to determine the benefit of eliminating all station blackout (SBO) events. This allows evaluation of possible improvements related to SBO sequences. For the purpose of the analysis, a single bounding analysis is performed that assumes the emergency AC power supplies do not fail.

Case NOSLB

Description: This case is used to determine the benefit of installing secondary side guard pipes to the main steam isolation valves (MSIVs). This would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. For the purposes of the analysis, a single bounding analysis was performed which assumed that no steam line break (SLB) events occur.

Case HEP1

Description: The probability of basic event OPRWM1, Operator aligns makeup to the RWST, given a SGTR with secondary leakage, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP2

Description: The probability of basic event OPROT1, Operator manually trips reactor within 1 minute, given automatic trip failed, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP3

Description: The probability of basic event OPROF2, Operator realigns Main Feedwater - no SI signal present, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP4

Description: The probability of basic event OPROS6, Operator manually actuates AFW following a transient, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP5

Description: The probability of basic event OPRDC2, Operator aligns spare battery charger 2-9 to BAT-CHG2-2, given that it has failed and the batteries are supplying the bus, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP6

Description: The probability of basic event OPRDC12, Operator aligns spare battery charger 2-7 to BAT-CHG2-1, given that it has failed and the batteries are supplying the bus, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP7

Description: The probability of basic event OPROB2, Operator initiates Bleed & Feed when AFW fails, given that MFW restoration was not attempted, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP8

Description: The probability of basic event OPROC1, Operator trips the RCPs during a loss of all CCP, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP9

Description: The probability of basic event OPROB1, Operator initiates Bleed & Feed when AFW fails, after attempting to realign MFW, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case HEP10

Description: The probability of basic event OPRSL1, Operator identifies ruptured S/G and initiates isolation, is reduced by a factor of 3. This case is used to evaluate improvements that would lower the associated human error probability.

Case LOCA01

Description: This case is used to determine the benefit of eliminating all small LOCA events. This case was used to evaluate improvements that would help mitigate small LOCA events.

Case LOCA02

Description: Assume High Pressure Injection system does not fail. This case was used to evaluate improvements in the high pressure injection systems.

Case LOCA03

Description: Assume Low Pressure Injection system does not fail. This case was used to evaluate improvements in the low pressure injection system.

Case LOCA04

Description: Assume the Refueling Water Storage Tank (RWST) inventory never depletes. This case was used to evaluate improvements that provide refill or backup to the RWST.

Case LOCA05

Description: Eliminate all piping failure LOCAs. No change for non-piping failure LOCAs such as SGTR, RCP Seal LOCA, stuck open SRV/PORV or ISLOCA. This case was used to evaluate improvements that would lower the probability of piping system LOCA events.

Case LOCA06

Description: Assume no ISLOCA events occur. This case is used to determine the benefit of eliminating all ISLOCA events.

Case DC1

Description: Assume the DC power system does not fail or deplete. This case is used to determine the impact of the improvement in the DC power system.

Case CHG01

Description: Eliminate the dependency of the charging pumps on cooling water. This case is used to determine the benefit of removing the charging pumps dependency on cooling water.

Case SW01

Description: Eliminate the dependency of the service water pumps on DC power. This case is used to determine the benefit of enhancing the DC control power to the service water pumps.

Case CCW01

Description: This case is used to determine the benefit of improvement to the Component Cooling Water (CCW) system by assuming that CCW pumps do not fail.

Case FW01

Description: Eliminate loss of feedwater initiating events. This case is used to determine the benefit of improvements to the feedwater and feedwater control systems.

Case RCPLOCA

Description: This case is used to determine the benefit of eliminating all RCP seal LOCA events except those associated with seismic events with a PGA greater than 0.35g. This allows evaluation of various possible improvements that could reduce the risk associated with RCP seal LOCA and other small LOCA events.

Case CONT01

Description: This case is used to determine the benefit of eliminating all containment failures due to overpressurization. This is analogous to considering a perfect filter with perfect hardware and perfect operation implemented on sequences that lead to any containment overpressure condition.

Case H2BURN

Description: Eliminate all hydrogen ignition and detonation events. This case is used to determine the benefit of eliminating all hydrogen ignition and burns.

Case CONT02

Description: Assume failures of containment isolation do not occur. This case is used to determine the benefit of eliminating all containment isolation failures.

Case FLOOD1

Description: This case eliminates the internal cable vault flooding from fire water. This case is used to evaluate improvements that would help eliminate or mitigate this flood.

Case FLOOD2

Description: This case eliminates the safeguards building N&S rooms internal flood. This case is used to evaluate improvements that would help eliminate or mitigate this flood.

Case FIRE05

Description: This case eliminates the fires in zone CB-3 that cause a total loss of main feedwater and auxiliary feedwater with subsequent failure of bleed and feed. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case FIRE06

Description: This case eliminates the fires in zone CT-1 that cause a total loss of service water. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case FIRE07

Description: This case eliminates the fires in zone SB-4 that cause a total loss of normal AC power with subsequent failure of emergency AC power and station crosstie leading to station blackout. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case FIRE08

Description: This case eliminates the fires in zone CV-1 that cause failure of service water train A. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case FIRE09

Description: This case eliminates the fires in zone CV-3 that cause failure of component cooling water (thermal barrier cooling) and service water with subsequent failure of reactor coolant pump seal injection. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case FIRE10

Description: This case eliminates the fires in zone DG1L1A, Emergency Diesel Generator (EDG) building. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case FIRE11

Description: This case eliminates the fires in zone DG2L1A, EDG building. This case is used to evaluate improvements that would help eliminate or mitigate this fire.

Case SBO1

Description: This case eliminates the failures of the EDGs due to failures in the fuel oil system. This case is used to evaluate the installation of a diesel fuel oil cross-tie between the units.

Case SEISMIC1

Description: This case reduces the failure of the Emergency Response Facility (ERF) Substation batteries due to seismic events (by setting the ERF Substation battery seismic capacity equivalent to the Unit 2 125V DC Emergency battery capacity). This case is used to evaluate the benefit of increasing the seismic ruggedness of the ERF Substation battery racks.

Case DAFW (new base case)

Description: This case is developed to assess the impact of the addition of a dedicated AFW pump powered by the ERF diesel generator and of a portable diesel generator for unlimited steam generator level instrumentation.

Case CONT01D

Description: This case is used to assess the impact of the already defined case CONT01 to the new base case DAFW.

Case NOSGTRD

Description: This case is used to assess the impact of the already defined case NOSGTR to the new base case DAFW.

Case CCW01D

Description: This case is used to assess the impact of the already defined case CCW01 to the new base case DAFW.

Case RCPLOCAD

Description: This case is used to assess the impact of the already defined case RCPLOCA to the new base case DAFW.

Case CHG01D

Description: This case is used to assess the impact of the already defined case CHG01 to the new base case DAFW.

Case NOSBOD

Description: This case is used to assess the impact of the already defined case NOSBO to the new base case DAFW.

Cases FLOOD1A, FLOOD1B, FLOOD1C, and FLOOD1D

Description: These cases were used to evaluate improved detection of piping degredation for the fire water piping that causes the flooding of CV-1. The CVFLF bin frequencies were divided by the initiating event frequency to obtain a conditional core damage (release bin) probability.

Sensitivity cases were performed by assuming that if an NDE was performed on the fire water piping the initiating event frequency would be reduced by a factor of 10, 2, or 20. The new initiating event frequency was multiplied by the CCDP of each release bin and added this value to the associated FLOOD1 release bin frequency (the FLOOD1 bin frequencies are without any CVFLF contribution).

FLOOD1D was developed analogously but the CCDP for each bin was multiplied by an HEP of 1E-3 to estimate the likelihood of the operators failing to isolate the leakage from the fire water pipe given the existing procedure which responds to the fire protection water flow alarm. The CCDPs, the HEP and the initiating event frequency were recombined to arrive at the fin frequencies.

<u>Cases SGTR2, SGTR3, SGTR4, and SGTR5</u>

Description: The SG sensitivity cases were performed assuming that the operator action to close the RCS loop stop valves or to gag closed the stuck-open SG SV would only have a 50% probability of success, as opposed to the 100% success probability assumed in the NOSGTR maximum benefit case. To perform the SG sensitivity cases, the sum of SGTR release bin frequencies were divided by the single SGTR initiating event frequency (1.6059E-03) to obtain the SGTR conditional core damage probabilities for each release bin. The following describes how these SGTR release bin frequency sums and conditional release bin frequencies were applied to each sensitivity case.

For the SGTR2 case, where the operators gag a stuck-open SV, only the unscrubbed containment bypass release bin frequency (BV18) would be impacted. Since the assumed operator action to gag closed the stuck-open SG SV has a 50% probability of success, the SGTR BV18 release bin frequency was multiplied by 0.5. However, since the total CDF from SGTRs would not change from performing this action, the other 50% of the BV18 release bin frequency was added to the scrubbed small release bin frequency (BV20). The remaining SGTR release bin frequency sums remained unchanged. These new SGTR bin frequencies were then added to the NOSGTR release bin frequencies to obtain the SGTR2 sensitivity case release bin frequencies.

For the SGTR3 case, where the operators close the RCS loop stop valves, all of the SGTR release bin frequencies are impacted, since this action would essentially terminate the SGTR. Since the assumed operator action to perform this action has a 50% probability of success, the SGTR initiating event frequency was multiplied by 0.5. This new initiating event frequency (8.0295E-04) was then multiplied by each of the SGTR conditional release bin probabilities. The resultant new SGTR bin frequencies were then added to the NOSGTR release bin frequencies to obtain the SGTR3 sensitivity case release bin frequencies.

For the SGTR4 case, where the operators close the RCS loop stop valves and gag a stuck-open SV, all of the SGTR release bin frequencies are impacted, since this action would essentially terminate the SGTR. Since the assumed operator action to perform this action has a 50% probability of success, the SGTR initiating event frequency was multiplied by 0.5. This new initiating event frequency (8.0295E-04) was then multiplied by each of the SGTR conditional release bin probabilities to obtain revised SGTR bin frequencies. Additionally, the unscrubbed containment bypass release bin frequency (BV18) would be reduced by a 50% probability of success for terminating the unscrubbed containment bypass release. Therefore, the revised SGTR BV18 release bin frequency was further reduced by multiplying it by 0.5, and the other 50% of the revised BV18 release bin frequency was added to the revised scrubbed small release bin frequency (BV20). These new SGTR bin frequencies were then added to the NOSGTR release bin frequencies to obtain the SGTR4 sensitivity case release bin frequencies.

For the SGTR5 case, where the steam generators were replaced, all of the SGTR release bin frequencies are impacted, since this would reduce the frequency of having an SGTR. The new SGTR initiating event frequency was assumed to be same as the Unit 1 SGTR frequency, where the replacement steam generators were already implemented. This new initiating event frequency (6.9656E-04) was then multiplied by each of the SGTR conditional release bin probabilities. These new SGTR bin frequencies were then added to the NOSGTR release bin frequencies to obtain the SGTR5 sensitivity case release bin frequencies.

Table A-5
BVPS Unit 2 Release Category Frequency Results Obtained From SAMA Cases

BV2 RELEASE CATEGORIES	U2BASE	INSTAIR1	NOATWS	NOLOSP	NOSBO	NOSGTR	NOSLB	HEP1	HEP2	HEP3
Intact	1.20E-06	1.20E-06	1.05E-06	1.15E-06	1.02E-06	1.20E-06	1.19E-06	1.20E-06	1.19E-06	1.20E-06
ECF-VSEQ	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07
ECF-SGTR	1.25E-07	1.25E-07	1.24E-07	7.40E-08	1.21E-07	0.00E+00	1.25E-07	1.18E-07	1.24E-07	1.24E-07
ECF-DCH	3.78E-09	3.79E-09	3.78E-09	3.27E-09	1.92E-09	3.78E-09	3.78E-09	3.78E-09	3.78E-09	3.77E-09
SECF-VSEQ	3.67E-06	3.67E-06	3.67E-06	3.53E-06	3.63E-06	3.43E-06	3.67E-06	3.66E-06	3.67E-06	3.67E-06
SECF-LOCI	1.13E-07	1.13E-07	1.12E-07	1.11E-07	9.72E-08	1.13E-07	1.13E-07	1.13E-07	1.13E-07	1.13E-07
SECF-BV5	2.70E-08	2.70E-08	2.70E-08	2.59E-08	1.79E-08	2.70E-08	2.70E-08	2.70E-08	2.70E-08	2.70E-08
LATE-LARGE	1.27E-08	1.27E-08	1.08E-08	1.22E-08	1.18E-08	1.27E-08	1.26E-08	1.27E-08	1.25E-08	1.26E-08
LATE-SMALL	1.84E-05	1.84E-05	1.84E-05	1.60E-05	1.03E-05	1.84E-05	1.84E-05	1.84E-05	1.84E-05	1.83E-05
LATE-H2BURN	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	0.00E+00
LATE-BMMT	1.81E-07	1.81E-07	1.74E-07	1.29E-07	1.13E-07	1.81E-07	1.81E-07	1.81E-07	1.80E-07	1.81E-07
CDF	2.40E-05	2.40E-05	2.39E-05	2.14E-05	1.56E-05	2.37E-05	2.40E-05	2.40E-05	2.40E-05	2.40E-05

Table A-1
BVPS Unit 2 Release Category Frequency Results Obtained From SAMA Cases (Cont.)

BV2 RELEASE CATEGORIES	HEP4	HEP5	HEP6	HEP7	HEP8	HEP9	HEP10	LOCA01	LOCA02	LOCA03
Intact	1.19E-06	1.20E-06	1.20E-06	9.57E-07	1.19E-06	1.18E-06	1.20E-06	1.14E-06	1.04E-06	1.17E-06
ECF-VSEQ	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07
ECF-SGTR	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	9.19E-08	1.25E-07	1.18E-07	1.25E-07
ECF-DCH	3.75E-09	3.78E-09	3.78E-09	3.74E-09	3.77E-09	3.78E-09	3.78E-09	3.91E-09	3.75E-09	3.78E-09
SECF-VSEQ	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.68E-06	3.67E-06	3.66E-06	3.67E-06
SECF-LOCI	8.91E-08	1.13E-07	1.13E-07	7.49E-08	1.13E-07	1.10E-07	1.13E-07	1.12E-07	1.05E-07	1.13E-07
SECF-BV5	1.25E-08	2.70E-08	2.70E-08	2.69E-08	2.67E-08	2.70E-08	2.70E-08	2.55E-08	2.70E-08	2.70E-08
LATE-LARGE	1.25E-08	1.27E-08	1.27E-08	1.00E-08	1.26E-08	1.24E-08	1.27E-08	1.20E-08	1.15E-08	1.24E-08
LATE-SMALL	1.83E-05	1.84E-05	1.84E-05	1.84E-05	1.84E-05	1.84E-05	1.84E-05	1.80E-05	1.84E-05	1.84E-05
LATE-H2BURN	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	0.00E+00
LATE-BMMT	1.80E-07	1.81E-07	1.81E-07	1.73E-07	1.78E-07	1.80E-07	1.81E-07	8.92E-08	1.60E-07	1.61E-07
CDF	2.38E-05	2.40E-05	2.40E-05	2.37E-05	2.40E-05	2.40E-05	2.40E-05	2.35E-05	2.38E-05	2.40E-05

Table A-1
BVPS Unit 2 Release Category Frequency Results Obtained From SAMA Cases (Cont.)

BV2 RELEASE CATEGORIES	LOCA04	LOCA05	LOCA06	CCW01	CONT01	FW01	DC1	CHG01	CONT02	RCPLOCA
Intact	1.20E-06	1.13E-06	1.20E-06	1.19E-06	1.16E-05	1.12E-06	1.20E-06	1.20E-06	1.20E-06	3.82E-10
ECF-VSEQ	2.80E-07	2.80E-07	0.00E+00	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	0.00E+00
ECF-SGTR	1.13E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	0.00E+00
ECF-DCH	3.78E-09	3.78E-09	3.78E-09	3.78E-09	2.74E-10	3.76E-09	1.20E-09	3.78E-09	3.76E-09	2.04E-09
SECF-VSEQ	3.64E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.63E-06	3.67E-06	3.67E-06	3.31E-06
SECF-LOCI	1.13E-07	1.13E-07	1.13E-07	1.13E-07	3.72E-08	1.10E-07	1.13E-07	1.13E-07	7.60E-08	2.63E-06
SECF-BV5	2.70E-08	2.70E-08	2.70E-08	2.69E-08	2.62E-08	2.56E-08	2.65E-08	2.70E-08	7.69E-10	6.85E-07
LATE-LARGE	1.26E-08	1.15E-08	1.27E-08	1.26E-08	0.00E+00	1.16E-08	1.27E-08	1.27E-08	1.27E-08	4.49E-13
LATE-SMALL	1.84E-05	1.84E-05	1.84E-05	1.84E-05	0.00E+00	1.83E-05	9.93E-06	1.84E-05	1.84E-05	8.35E-06
LATE-H2BURN	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	0.00E+00
LATE-BMMT	1.75E-07	1.54E-07	1.81E-07	1.81E-07	8.29E-06	1.76E-07	1.81E-07	1.81E-07	1.81E-07	1.09E-10
CDF	2.40E-05	2.39E-05	2.37E-05	2.40E-05	2.40E-05	2.38E-05	1.55E-05	2.40E-05	2.40E-05	1.50E-05

Table A-1
BVPS Unit 2 Release Category Frequency Results Obtained From SAMA Cases (Cont.)

BV2 RELEASE CATEGORIES	H2BURN	SW01	FLOOD1	FLOOD2	FIRE05	FIRE06	FIRE07	FIRE08	FIRE09	FIRE10
Intact	1.28E-06	1.20E-06	1.20E-06	1.20E-06	7.96E-07	1.20E-06	1.20E-06	1.20E-06	1.16E-06	1.19E-06
ECF-VSEQ	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07
ECF-SGTR	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07
ECF-DCH	3.77E-09	3.78E-09	3.78E-09	3.73E-09	3.71E-09	3.74E-09	3.77E-09	3.78E-09	3.72E-09	3.55E-09
SECF-VSEQ	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06
SECF-LOCI	3.85E-08	1.13E-07	1.13E-07	1.13E-07	4.93E-08	1.13E-07	1.13E-07	1.13E-07	1.13E-07	1.13E-07
SECF-BV5	2.70E-08	2.70E-08	2.70E-08	2.68E-08	2.67E-08	2.70E-08	2.70E-08	2.70E-08	2.61E-08	2.68E-08
LATE-LARGE	0.00E+00	1.27E-08	1.27E-08	1.27E-08	8.19E-09	1.27E-08	1.27E-08	1.27E-08	1.24E-08	1.26E-08
LATE-SMALL	1.84E-05	1.84E-05	1.78E-05	1.81E-05	1.84E-05	1.73E-05	1.84E-05	1.84E-05	1.81E-05	1.75E-05
LATE-H2BURN	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	0.00E+00
LATE-BMMT	1.87E-07	1.81E-07	1.81E-07	1.81E-07	1.66E-07	1.81E-07	1.81E-07	1.81E-07	1.53E-07	1.77E-07
CDF	2.40E-05	2.40E-05	2.34E-05	2.37E-05	2.35E-05	2.29E-05	2.40E-05	2.40E-05	2.37E-05	2.31E-05

Table A-1
BVPS Unit 2 Release Category Frequency Results Obtained From SAMA Cases (Cont.)

BV2 RELEASE CATEGORIES	FIRE11	SEISMIC1	SBO1	FLOOD1A	FLOOD1B	FLOOD1C	SGTR2	SGTR3	SGTR4	SGTR5
Intact	1.19E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06
ECF-VSEQ	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07
ECF-SGTR	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	1.25E-07	6.26E-08	6.26E-08	3.13E-08	5.43E-08
ECF-DCH	3.55E-09	3.77E-09	3.74E-09	3.78E-09	3.78E-09	3.78E-09	3.78E-09	3.78E-09	3.78E-09	3.78E-09
SECF-VSEQ	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.67E-06	3.74E-06	3.55E-06	3.58E-06	3.54E-06
SECF-LOCI	1.13E-07	1.13E-07	1.13E-07	1.13E-07	1.13E-07	1.13E-07	1.13E-07	1.13E-07	1.13E-07	1.13E-07
SECF-BV5	2.68E-08	2.70E-08	2.70E-08	2.70E-08	2.70E-08	2.70E-08	2.70E-08	2.70E-08	2.70E-08	2.70E-08
LATE-LARGE	1.26E-08	1.27E-08	1.26E-08	1.27E-08	1.27E-08	1.27E-08	1.27E-08	1.27E-08	1.27E-08	1.27E-08
LATE-SMALL	1.75E-05	1.84E-05	1.82E-05	1.79E-05	1.81E-05	1.78E-05	1.84E-05	1.84E-05	1.84E-05	1.84E-05
LATE-H2BURN	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	0.00E+00
LATE-BMMT	1.79E-07	1.81E-07	1.80E-07	1.81E-07	1.81E-07	1.81E-07	1.81E-07	1.81E-07	1.81E-07	1.81E-07
CDF	2.31E-05	2.40E-05	2.38E-05	2.35E-05	2.37E-05	2.35E-05	2.40E-05	2.38E-05	2.38E-05	2.38E-05

BV2 RELEASE CATEGORIES	Mod Base for SAMA 118	LOCA06a	Mod Base for SAMA 187	FLOOD1
Intact	1.20E-06	1.20E-06	1.20E-06	1.20E-06
ECF-VSEQ	9.99E-10	0.00E+00	2.80E-07	2.80E-07
ECF-SGTR	1.25E-07	1.25E-07	1.25E-07	1.25E-07
ECF-DCH	3.78E-09	3.78E-09	3.78E-09	3.78E-09
SECF-VSEQ	3.67E-06	3.67E-06	3.67E-06	3.67E-06
SECF-LOCI	1.13E-07	1.13E-07	1.13E-07	1.13E-07
SECF-BV5	2.70E-08	2.70E-08	2.70E-08	2.70E-08
LATE-LARGE	1.27E-08	1.27E-08	1.27E-08	1.27E-08
LATE-SMALL	1.84E-05	1.84E-05	1.78E-05	1.78E-05
LATE-H2BURN	0.00E+00	0.00E+00	0.00E+00	0.00E+00
LATE-BMMT	1.81E-07	1.81E-07	1.81E-07	1.81E-07
CDF	2.37E-05	2.37E-05	2.34E-05	2.34E-05