Attachment C

SQN National Pollutant Discharge Elimination System (NPDES) Permit

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SQN National Pollutant Discharge Elimination System (NPDES) Permit

- NPDES Permit TN0026450

STATE OF TENNESSEE
DEPARTMENT OF ENVIRONMENT AND CONSERVATION

DIVISION OF WATER POLLUTION CONTROL
401 CHURCH STREET
L & C ANNEX 6TH FLOOR
NASHVILLE TN 37243

FEB 02 2011

Mr. Timothy P. Cleary
Site Vice President
TVA Sequoyah Nuclear Plant
Sequoyah Access Rd.
P.O. Box 2000 (OPS-4A)
Soddy Daisy, TN 37384

Subject: NPDES Permit No. TN0026450
TVA - Sequoyah Nuclear Plant
Soddy Daisy, Hamilton County, Tennessee

Dear Mr. Cleary:

In accordance with the provisions of the Tennessee Water Quality Control Act, Tennessee Code Annotated (T.C.A.), Sections 69-3-101 through 69-3-120, the Division of Water Pollution Control hereby issues the enclosed NPDES Permit. The continuance and/or reissuance of this NPDES Permit is contingent upon your meeting the conditions and requirements as stated therein.

Please be advised that a petition for permit appeal may be filed, pursuant to T.C.A. Section 69-3-105, subsection (i), by the permit applicant or by any aggrieved person who participated in the public comment period or gave testimony at a formal public hearing whose appeal is based upon any of the issues that were provided to the commissioner in writing during the public comment period or in testimony at a formal public hearing on the permit application. Additionally, for those permits for which the department gives public notice of a draft permit, any permit applicant or aggrieved person may base a permit appeal on any material change to conditions in the final permit from those in the draft, unless the material change has been subject to additional opportunity for public comment. Any petition for permit appeal under this subsection (i) shall be filed with the board within thirty (30) days after public notice of the commissioner's decision to issue or deny the permit.

If you have questions, please contact the Division of Water Pollution Control at your local Field Office at 1-888-891-TDEC; or, at this office, please contact Mr. Bob Alexander at (615) 532-0659 or by E-mail at *Robert.Alexander@tn.gov.*

Sincerely,

Vojin Janjić
Manager, Permit Section
Division of Water Pollution Control

cc/ec: DWPC, Permit Section & Chattanooga Environmental Field Office
Ms. Stephanie Howard, Environmental Engineer, TVA - Sequoyah Nuclear Plant, sahoward@tva.gov
Ms. Linden (Lindy) P. Johnson, Manager - Water Permitting & Compliance, lpjohnson@tva.gov
Ms. Connie A. Kagey, NPDES Permit Section, EPA Region IV, Kagey.Connie@epamail.epa.gov
Mr. Michael D. Skaggs, WBN Vice President, TVA - Watts Bar Nuclear Plant, mdskaggs@tva.gov
Mr. Brian Paddock, Attorney, Save Our Cumberland Mountains (SOCM), bpaddock@twlakes.net

STATE OF TENNESSEE

NPDES PERMIT

No. TN0026450

Authorization to discharge under the
National Pollutant Discharge Elimination System (NPDES)

Issued By

Tennessee Department of Environment and Conservation
Division of Water Pollution Control
401 Church Street
6th Floor, L & C Annex
Nashville, Tennessee 37243-1534

Under authority of the Tennessee Water Quality Control Act of 1977 (T.C.A. 69-3-101 et seq.) and the delegation of authority from the United States Environmental Protection Agency under the Federal Water Pollution Control Act, as amended by the Clean Water Act of 1977 (33 U.S.C. 1251, et seq.)

Discharger:	**TVA – SEQUOYAH NUCLEAR PLANT**
is authorized to discharge:	**process and non-process wastewater through Outfalls 101, 110, 116, 117, and 118, and Internal Monitoring Points (IMP) 103, and 107**
from a facility located:	**in Soddy Daisy, Hamilton County, Tennessee**
to receiving waters named:	**Tennessee River at mile 483.65 (Outfall 101), 485.2 (Outfall 116), 484.852 (Outfall 117), and 484.8 (Outfall 118)**

in accordance with effluent limitations, monitoring requirements and other conditions set forth herein.

This permit shall become effective on:	**March 1, 2011**
This permit shall expire on:	**October 31, 2013**
Issuance date:	**January 31, 2011**

FOR

Paul E. Davis, Director
Division of Water Pollution Control

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TN0026450.doc

PART I

A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

1. Outfall 101

TVA - Sequoyah Nuclear Plant is authorized to discharge process and non-process wastewater (condenser circulating water, essential raw cooling water, cooling tower blowdown, raw cooling water, low volume wastes, miscellaneous low volume wastes, including various facilities drains and sumps, A/C condensate, steam generator blowdown, high pressure fire protection water, regeneration wastes from condensate demineralizer and stormwater runoff) through Outfall 101 to the Tennessee River at mile 483.65. The discharge shall be limited and monitored by the permittee as specified below:

Feature Description : External Outfall, Number : 101
Monitoring : Effluent Gross, Season : All Year

Parameter	Qualifier	Limit	Unit	Sample Type	Frequency	Statistical Base
Chlorine, total residual	<=	.1	mg/L	Calculated	Weekdays	Daily Maximum
Chlorine, total residual	<=	.1	mg/L	Calculated	Weekdays	Monthly Average
Flow, in conduit or thru treatment plant	Report	-	Mgal/d	Recorder	Continuous	Daily Maximum
Flow, in conduit or thru treatment plant	Report	-	Mgal/d	Calculated	Daily	Monthly Average
Temperature, water deg. centigrade	Report	-	deg C	Calculated	Continuous	Daily Maximum
IC25 Static Renewal 7 Day Chronic Chrceriodaphnia	>=	43.2	%	Composite	Monthly	Minimum
IC25 Static Renewal 7 Day Chronic Chrpimephales	>=	43.2	%	Composite	Monthly	Minimum

Monitoring : Effluent Gross, Season : Winter

Parameter	Qualifier	Limit	Unit	Sample Type	Frequency	Statistical Base
Temp. diff. between samp. & upstrm deg. C	<=	5	deg C	Calculated	Continuous	Daily Maximum

Monitoring : Instream Monitoring, Season : All Year

Parameter	Qualifier	Limit	Unit	Sample Type	Frequency	Statistical Base
Temperature rate of change deg. C/hr	<=	2	deg C/hr	Calculated	Continuous	Daily Maximum
Temperature, water deg. centigrade	<=	30.5	deg C	Calculated	Continuous	Daily Maximum

Monitoring : Instream Monitoring, Season : Summer

Parameter	Qualifier	Limit	Unit	Sample Type	Frequency	Statistical Base
Temp. diff. between samp. & upstrm deg. C	<=	3	deg C	Calculated	Continuous	Daily Maximum

Samples taken in compliance with the monitoring requirements specified above shall be taken as follows: flow – sampled at diffuser gate prior to entry to the Tennessee River; ambient temperature - from station 14 located at TN River mile 490.5 upstream of SQN; river temperature – river temperature, temperature rise and rate of temperature change shall be determined by numerical model.

WET testing frequency and results reporting will be governed by the B/CTP. However, in order to effectively track WET monitoring monthly reporting shall continue. For monitoring periods when WET testing is not required by the approved B/CTP; monitoring not required (or MNR) shall be reported on the discharge monitoring reports (DMRs) or the electronic report (if being used) to reflect that monitoring is not required.

See Part III of this permit for further description of toxicity tests.

TRC analysis shall be performed within fifteen (15) minutes of sample collection.

The acceptance methods for analysis of TRC are any methods specified in Title 40 CFR, Part 136, as amended. The method detection level (MDL) for TRC shall not exceed 0.08 mg/L unless the permittee demonstrates that its MDL is higher. The permittee shall retain the documentation that justifies the higher MDL and have it available for review upon request. Under the renewed permit limits, reporting of TRC at less than 0.08 mg/L shall be interpreted to constitute compliance with the permit.

The following requirements also apply to discharges from Outfall 101:

a. Compliance with the river limitations (river temperature, temperature rise, and rate of temperature change) shall be monitored by means of a numerical model that solves the thermohydrodynamic equations governing the flow and thermal conditions in the reservoir. This numerical model will utilize measured values of the upstream temperature profile and river stage; flow, temperature and performance characteristics of the diffuser discharge; and river flow as determined from releases at the Watts Bar and Chickamauga Dams. In the event that the modeling system described here is out of service, an alternate method will be employed to measure water temperatures at least one time per day and verify compliance of the maximum river temperature and maximum temperature rise.

b. Depth average measurements can be taken at a backup temperature monitor at the downstream end of the diffuser mixing zone (left bank Tennessee River Mile 483.4, Station 8) or by grab sampling from boats. Boat sampling will include average 5-foot depth measurements (average of 3, 5, and 7-foot depths). Sampling from a boat shall be made at Station 14, at about. Tennessee River Mile 490.5 (ambient temperature) and at quarter points and mid-channel at Tennessee River Mile 483.4 (downstream temperature). The downstream reported value will be a depth (3, 5, and 7 foot) and lateral (quarter points and midpoint) average of the instream measurements. Monitoring in the alternative mode using boat sampling shall not be required when unsafe boating conditions occur.

c. Compliance with river temperature, temperature rise, and rate of temperature change limitations shall be applicable at the edge of a mixing zone which shall not exceed the following dimensions: (1) a maximum length of 1500 feet downstream of the diffusers, (2) a maximum width of 750 feet, and (3) a maximum length of 275 feet upstream of the diffusers. The depth of the mixing zone measured from the surface varies linearly from the surface 275 feet upstream of the diffusers to the top of the diffuser pipes and extends to the bottom downstream of the diffusers. When the plant is operated in closed mode, the mixing zone shall also include the area of the intake forebay.

d. Information required by the numerical model and evaluations for the river temperature, temperature rise, and rate of temperature change shall be made every 15 minutes. The ambient temperature shall be determined at the 5-foot depth as the average of measurements at depths 3 feet, 5 feet, and 7 feet. The river temperature at the downstream end of the mixing zone shall be determined as that computed by the numerical model at a depth of 5 feet.

e. Daily maximum temperatures for the ambient temperature, the river temperature at the downstream edge of the mixing zone, and temperature rise shall be determined from 24-hour average values. The 24-hour average values shall be calculated every 15 minutes using the current and previous ninety-six 15-minute values, thus creating a 'rolling' average. The maximum of the ninety-six observations generated per day by this procedure shall be reported as the daily maximum value. For the river temperature downstream end of the mixing zone, the 1-hour average shall also be determined. The 1-hour average values shall be calculated every 15 minutes using the average of the current and previous four 15-minute values, again creating a rolling average.

f. The daily maximum 24-hour average river temperature is limited to 30.5°C. Since the state's criteria makes exception for exceeding the value as a result of natural conditions, where the 24-hour average ambient temperature exceeds 29.4°C and the plant is operated in helper mode the maximum temperature may exceed 30.5°C. In no case shall the plant discharge cause the 1-hour average river temperature at the downstream edge of the mixing zone to exceed 33.9°C without the consent of the permitting authority.

g. The temperature rise is the difference between the 24-hour average ambient river temperature and the 24-hour average temperature at the downstream edge of the mixing zone. The 24-hour average temperature rise shall be limited to 3.0 C° during the months of April through October. The 24-hour average temperature rise shall be limited to 5.0 C° during the months of November through March.

h. The rate of temperature change shall be computed at 15-minute intervals based on the current 24-hour average ambient river temperature, current 24-hour average river flow, and current 15-minute values of flow and temperature of water discharging through the diffuser pipes. The 1-hour average rate of temperature change shall be calculated every 15-minutes by averaging the current and previous four 15-minute values. The 1-hour average rate of temperature change shall be limited to 2 C° per hour.

i. During periods when the Essential Raw Cooling Water (ERCW) and/or Raw Cooling Water (RCW) systems are receiving applications of biocides, (oxidizing or non-oxidizing), chemical dispersants, or detoxicant chemical additives, the permittee shall implement the Biocide/Corrosion Treatment Plan (B/CTP), which was approved April 27, 2005, and all subsequent revisions as approved by the Division. The B/CTP [plan] for these activities describes the specific chemical additive, material feed rate, method detection level (MDL) for the active compound(s), and the allowable concentration and/or mass limits, and actions proposed to ensure compliance with established effluent limitations during application. The B/CTP refers to the NPDES permit for specific language associated with monitoring Total Residual Chlorine (TRC). Note: the term TRC will encompass all references to any oxidants (i.e. chlorine/bromine) in use at the SQN facility; therefore, the acronym "TRO" may be used interchangeably. WET frequency and results reporting will be governed by the B/CTP. The permit table for Outfall 101 will state that WET testing frequency and results reporting will be governed by the B/CTP. However, in order to effectively track WET monitoring monthly, reporting shall continue. For monitoring periods when WET testing is not required by the approved B/CTP; monitoring not required, or "MNR" shall be reported on the discharge monitoring report (DMR) or the electronic report (if being used) to reflect that monitoring is not required.

j. Total Residual Chlorine shall be sampled downstream of the chlorine injection points but prior to mixing with any other waste streams. TRC shall be calculated for the diffuser discharge (Outfall 101) based on these analyses and the proportional flows of the Condenser Circulating Water (CCW), ERCW, and RCW systems to indicate whether permit limits may be in danger of being exceeded. This calculation is a simple dilution calculation to project the maximum amount of chlorine that could be present at the discharge. The calculation will not allow for the decay of residual chlorine. If the CCW system is to be chlorinated or chlorination of the ERCW and/or RCW system is to occur while none of the units are discharging flow from the CCW system (i.e. zero CCW pumps in service), the B/CTP shall be revised and submitted to the Division for approval prior to initiation of the changes.

k. Any substance, including radioactive materials, is of interest to our Agency if it has reasonable potential to exceed applicable water quality criteria. However, radioactive releases to the environment, notwithstanding point source discharges authorized via this permit, are not regulated under the Clean Water Act, but are instead **regulated under the Nuclear Regulatory Commission (NRC) by issuance of an Operating License.** Pertinent regulations are found under 10 CFR Part 20 and 10 CFR Part 50. Sequoyah Nuclear Plant effluents that may contain radioactive material are not addressed as part of the NPDES permitting process.

2. Internal Monitoring Point (formerly Outfall) 103

TVA-Sequoyah Nuclear Plant is authorized to discharge wastewater from the Low Volume Waste Treatment Pond through an internal monitoring point, IMP103 discharges into the Diffuser Pond, which finally discharges through Outfall 101. Wastewater consists of condensate demineralizer (CONDI), turbine building sump, stormwater from IMP 107, essential raw cooling water, raw cooling water and storm water runoff.

This discharge shall be limited and monitored by the permittee as specified below:

Description : Internal Outfall, Number : 103, Monitoring : Effluent Gross, Season : All Year

Parameter	Qualifier	Limit	Units	Sample Type	Frequency	Statistical base
Flow, in conduit or thru treatment plant	Report	-	Mgal/d	Totalizer	Continuous	Daily Maximum
Flow, in conduit or thru treatment plant	Report	-	Mgal/d	Totalizer	Continuous	Monthly Average
Oil & Grease	<=	**20**	mg/L	Grab	Twice Every Month	Daily Maximum
Oil & Grease	<=	**15**	mg/L	Grab	Twice Every Month	Monthly Average
Solids, total suspended	<=	**100**	mg/L	Grab	Twice Every Month	Daily Maximum
Solids, total suspended	<=	**30**	mg/L	Grab	Twice Every Month	Monthly Average
pH	<=	**9**	SU	Grab	Three Per Week	Maximum
pH	>=	**6**	SU	Grab	Three Per Week	Minimum

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following locations: low volume treatment pond discharge prior to mixing with other waste streams.

In the event that the turbine building sump is discharged directly to the CCW channel or the yard drainage pond, TSS, Oil and Grease and pH shall be monitored 5/Week.

3. Internal Monitoring Point (formerly Outfall) 107

TVA Sequoyah Nuclear Plant is authorized to discharge rain water from the defunct metal cleaning ponds into the Low Volume Waste Treatment Pond, (IMP103) which discharges into the Diffuser Pond (Outfall101). TVA will be allowed to direct rainwater that falls in the now defunct metal cleaning ponds to the Low Volume Waste Treatment Pond without any requirements to monitor the discharge at the defunct metal cleaning ponds (IMP107). TVA will put in place a procedure to ensure that no wastewater will be discharge to the metal cleaning ponds.

4. Outfall 110

TVA - Sequoyah Nuclear Plant is authorized to discharge backwash wastewater through Outfall 110, to the cooling channel and intake forebay. Note that Outfall 110 is not normally used in day-to-day operations of the plant and effluent limitations and monitoring requirements are applicable only during periods of **closed-mode operation**. However, should conditions apply that require its use as the main discharge point in place of Outfall 101 the same requirements of Outfall 101 shall apply to Outfall 110.

5. Outfall 116 and 117

TVA - Sequoyah Nuclear Plant is authorized to discharge backwash wastewater through Outfall 116 to the Tennessee River at mile 485.2 and through Outfall 117 to the Tennessee River at mile 484.85. There are no limits or monitoring requirements for these discharges.

6. Outfall 118

TVA - Sequoyah Nuclear Plant is authorized to discharge settling pond water and storm water runoff (only applicable when the pond is in service) through Outfall 118 to the intake forebay at Tennessee River mile 484.8.

These discharges shall be limited and monitored by the permittee as specified below:

Description : External Outfall, Number : 118, Monitoring : Effluent Gross, Season : All Year

Parameter	Qualifier	Limit	Unit	Sample Type	Frequency	Statistical base
Flow, in conduit or thru treatment plant	Report	-	Mgal/d	Estimate	Once Per Batch	Daily Maximum
Flow, in conduit or thru treatment plant	Report	-	Mgal/d	Estimate	Once Per Batch	Monthly Average
Oxygen, dissolved (DO)	>=	**2**	mg/L	Grab	Twice Every Week	Minimum
Solids, settleable	<=	**1**	mL/L	Grab	Monthly	Daily Maximum
Solids, total suspended	<=	**100**	mg/L	Grab	Twice Every Week	Daily Maximum

There shall be no discharge of floating scum, solids, oil sheen, visible foam, and other floating matter in other than trace amounts

Samples taken in compliance with the monitoring requirements specified above shall be taken of a discharge from the settling pond prior to mixing with the Intake Forebay.

Grab samples shall be taken at these frequencies, including a grab sample taken immediately prior to termination of the batch discharge.

These effluent limitations and monitoring requirements only apply at times when this settling pond is in use as a settling basin for dredged sediment. Best Management Practices (BMP) shall be used to control runoff from the pond. Examples include vegetative cover, silt fences, and/or hay bales.

7. Additional monitoring requirements and conditions applicable to all Outfalls include:

a) Flow shall be reported in Million Gallons per Day (MGD)

b) No discharge of polychlorinated biphenyl compounds (PCB) is allowed under this permit.

c) There shall be no distinctly visible floating scum, solids, oil sheen, visible foam, and other floating matter discharged with the wastewater to the receiving stream. The wastewater discharge must not cause an **objectionable color contrast in the receiving stream.**

d) The wastewater discharge shall not contain pollutants in quantities that will be hazardous or otherwise detrimental to humans, livestock, wildlife, plant life, or fish and aquatic life in the receiving stream.

e) Sludge or any other material removed by any treatment works must be disposed of in a manner that prevents its entrance into or pollution of any surface or subsurface waters. Additionally, the disposal of such sludge or other material must be in compliance with the Tennessee Solid Waste Disposal Act, TCA 68-31-101 et seq. and the Tennessee Hazardous Waste Management Act, TCA 68-46-101 et seq.

f) Priority Pollutants will not be discharged in cooling tower blowdown in amounts that are detectable by analytical methods in 40 CFR Part 136. Monitoring for the Priority Pollutants will not be required unless making application for new NPDES permit.

B. MONITORING PROCEDURES

1. Representative Sampling

Samples and measurements taken in compliance with the monitoring requirements specified herein shall be representative of the volume and nature of the monitored discharge, and shall be taken after treatment and prior to mixing with uncontaminated storm water runoff or the receiving stream.

2. Sampling Frequency

Where the permit requires sampling and monitoring of a particular effluent characteristic(s) at a frequency of less than once per day or daily, the permittee is precluded from marking the “No Discharge” block on the Discharge Monitoring Report if there has been any discharge from that particular outfall during the period which coincides with the required monitoring frequency, i.e. if the required monitoring frequency is once per month or 1/month, the monitoring period is one month, and if the discharge occurs during only one day in that period then the permittee must sample on that day and report the results of analyses accordingly.

3. Test Procedures

a. Test procedures for the analysis of pollutants shall conform to regulations published pursuant to Section 304 (h) of the Clean Water Act (the "Act"), as amended, under which such procedures may be required.

b. Unless otherwise noted in the permit, all pollutant parameters shall be determined according to methods prescribed in Title 40, CFR, Part 136, as amended, and promulgated pursuant to Section 304 (h) of the Act.

c. The acceptable methods for analysis of TRC are any methods specified in Title 40, CFR Part 136. The method detection level (MDL) for TRC shall not exceed 0.05mg/L unless the permittee demonstrates that its

MDL is higher. The permittee shall retain the documentation that justifies the higher MDL, and shall have that documentation available for review upon request. In cases where the permit limit is less than the MDL, the reporting of TRC at less than the MDL shall be interpreted to constitute compliance with the permit limit.

4. Recording of Results

For each measurement or sample taken pursuant to the requirements of this permit, the permittee shall record the following information:

a. The exact place, date and time of sampling;

b. The exact person(s) collecting samples;

c. The dates and times the analyses were performed;

d. The person(s) or laboratory that performed the analyses;

e. The analytical techniques or methods used, and;

f. The results of all required analyses.

5. Records Retention

All records and information resulting from the monitoring activities required by this permit including all records of analyses performed and calibration and maintenance of instrumentation shall be retained for a minimum of three (3) years, or longer, if requested by the Division of Water Pollution Control.

C. DEFINITIONS

The ***Daily Maximum Concentration*** is a limitation on the average concentration, in milligrams per liter (mg/L), of the discharge during any calendar day. When a proportional-to-flow composite sampling device is used, the daily concentration is the concentration of that 24-hour composite; when other sampling means are used, the daily concentration is the arithmetic mean of the concentrations of equal volume samples collected during any calendar day or sampling period.

The ***Monthly Average Concentration***, a limitation on the discharge concentration, in milligrams per liter (mg/L), is the arithmetic mean of all daily concentrations determined in a one-month period. For the purpose of this definition, a frequency of 2/Month is representative of 2 separate daily samples, each sample having been collected on a separate day during the monitoring period.

The ***Monthly Average Amount***, a discharge limitation measured in pounds per day (lb/day), is the total amount of any pollutant in the discharge by weight during a calendar month divided by the number of days in the month that the production or commercial facility was operating. Where less than daily sampling is required by a permit, the monthly average amount shall be determined by the summation of all the measured daily discharges by weight divided by the number of days during the calendar month when the measurements were made. For the purpose of this definition, a frequency of 2/Month is representative of 2 separate daily samples, each sample having been collected on a separate day during the monitoring period.

The ***Daily Maximum Amount*** is a limitation measured in pounds per day (lb/day), on the total amount of any pollutant in the discharge by weight during any calendar day.

The ***Instantaneous Concentration*** is a limitation on the concentration, in milligrams per liter (mg/L), of any pollutant contained in the discharge determined from a grab sample taken at any point in time.

For the purpose of this permit a ***Totalizer*** is a device or meter that continuously measures and calculates (adds) total flows in gallons, million gallons, cubic feet, or some other unit of volume measurement.

For the purposes of this permit, a ***Composite Sample**** for non-storm water discharges is a sample composed of equal aliquots collected at the rate of at least once per hour at regular time intervals over the period of discharge in a 24-hour period and combined into a single sample. A composite sample may also be a sample collected continuously over a period of 24 hours at a rate proportional to the flow. (*Except for sampling associated with Biomonitoring; use procedures for sampling from EPA-821-R-02-013, or most current edition.)

Continuous Discharge: A routine release to the environment that occurs without interruption, except for infrequent shutdowns for maintenance, process changes, etc.

For the purpose of this permit a ***Recorder*** is a device that makes a graph or other automatic record of the stage, pressure, depth, velocity, or the movement or position of water controlling devices, usually as a function of time.

A ***Grab Sample***, for the purposes of this permit, is defined as a single effluent sample of at least 100 milliliters collected over a period not exceeding 15 minutes. The sample(s) shall be collected at the period(s) most representative of the total discharge.

For the purpose of this permit, a ***Calendar Day*** is defined as any 24-hour period.

For the purpose of this permit, a ***Quarter*** is defined as any one of the following three month periods: January 1 through March 31, April 1 through June 30, July 1 through September 30, or October 1 through December 31.

For the purpose of this permit, ***Semi-annually*** means the same as "once every six months." Measurements of the effluent characteristics concentrations may be made anytime during a 6 month period beginning from the issuance date of this permit so long as the second set of measurements for a given 12 month period are made approximately 6 months subsequent to that time, if feasible.

For the purpose of this permit, ***Annually*** is defined as a monitoring frequency of once every twelve (12) months beginning with the date of issuance of this permit so long as the following set of measurements for a given 12 month period are made approximately 12 months subsequent to that time.

D. REPORTING

1. Monitoring Results

Monitoring results shall be recorded monthly and submitted monthly using Discharge Monitoring Report (DMR) forms supplied by the Division of Water Pollution Control or comparable forms provided by the permittee, and approved by the Division of Water Pollution Control. Submittals shall be postmarked no later than 15 days after the completion of the reporting period. The top two copies of each report are to be submitted. A copy should be retained for the permittee's files. DMRs and any communication regarding compliance with the conditions of this permit must be sent to:

TENNESSEE DEPT. OF ENVIRONMENT & CONSERVATION
DIVISION OF WATER POLLUTION CONTROL
COMPLIANCE REVIEW SECTION
401 CHURCH STREET
L & C ANNEX 6TH FLOOR
NASHVILLE TN 37243-1534

The first DMR is due on the fifteenth of the month following permit effectiveness.

DMRs and any other information or report must be signed and certified by a responsible corporate officer as defined in 40 CFR 122.22, a general partner or proprietor, or a principal municipal executive officer or ranking elected official or his duly authorized representative. Such authorization must be submitted in writing and must explain the duties and responsibilities of the authorized representative.

The electronic submission of DMRs shall be accepted only if approved in writing by the division. For purposes of determining compliance with this permit, data submitted in electronic format is legally equivalent to data submitted on signed and certified DMR forms.

2. Additional Monitoring by Permittee

If the permittee monitors any pollutant specifically limited by this permit more frequently than required at the location(s) designated, using approved analytical methods as specified herein, the results of such monitoring shall be included in the calculation and reporting of the values required in the DMR form. Such increased frequency shall also be indicated on the form.

3. Falsifying Reports

Knowingly making any false statement on any report required by this permit may result in the imposition of criminal penalties as provided for in Section 309 of the Federal Water Pollution Control Act, as amended, and in Section 69-3-115 of the Tennessee Water Quality Control Act.

4. Outlier Data

Outlier data include analytical results that are probably false. The validity of results is based on operational knowledge and a properly implemented quality assurance program. False results may include laboratory artifacts, potential sample tampering, broken or suspect sample containers, sample contamination or similar demonstrated quality control flaw.

Outlier data are identified through a properly implemented quality assurance program, and according to ASTM standards (e.g. Grubbs Test, 'h' and 'k' statistics). Furthermore, outliers should be verified, corrected, or removed, based on further inquiries into the matter. If an outlier was verified (through repeated testing and/or analysis), it should remain in the preliminary data set. If an outlier resulted from a transcription or similar clerical error, it should be corrected and subsequently reported.

Therefore, only if an outlier was associated with problems in the collection or analysis of the samples, and as such does not conform with the Guidelines Establishing Test Procedures for the Analysis of Pollutants (40 CFR §136), it can be removed from the data set and not reported on the Discharge Monitoring Report forms (DMRs). Otherwise, all results (including monitoring of pollutants more frequently than required at the location(s) designated, using approved analytical methods as specified in the permit) should be included in the calculation and reporting of the values required in the DMR form. The permittee is encouraged to use "comment" section of the DMR form (or attach additional pages), in order to explain any potential outliers or dubious results.

E. SCHEDULE OF COMPLIANCE

Full compliance and operational levels shall be attained from the effective date of this permit.

PART II

A. GENERAL PROVISIONS

1. Duty to Reapply

Permittee is not authorized to discharge after the expiration date of this permit. In order to receive authorization to discharge beyond the expiration date, the permittee shall submit such information and forms as are required to the Director of Water Pollution Control (the "Director") no later than 180 days prior to the expiration date. Such applications must be properly signed and certified.

2. Right of Entry

The permittee shall allow the Director, the Regional Administrator of the U.S. Environmental Protection Agency, or their authorized representatives, upon the presentation of credentials:

a. To enter upon the permittee's premises where an effluent source is located or where records are required to be kept under the terms and conditions of this permit, and at reasonable times to copy these records;

b. To inspect at reasonable times any monitoring equipment or method or any collection, treatment, pollution management, or discharge facilities required under this permit; and

c. To sample at reasonable times any discharge of pollutants.

3. Availability of Reports

Except for data determined to be confidential under Section 308 of the Federal Water Pollution Control Act, as amended, all reports prepared in accordance with the terms of this permit shall be available for public inspection at the offices of the Division of Water Pollution Control. As required by the Federal Act, effluent data shall not be considered confidential.

4. Proper Operation and Maintenance

a. The permittee shall at all times properly operate and maintain all facilities and systems (and related appurtenances) for collection and treatment which are installed or used by the permittee to achieve compliance with the terms and conditions of this permit. Proper operation and maintenance also includes adequate laboratory and process controls and appropriate quality assurance procedures. This provision requires the operation of backup or auxiliary facilities or similar systems, which are installed by a permittee only when the operation is necessary to achieve compliance with the conditions of the permit. Backup continuous pH and flow monitoring equipment are not required.

b. Dilution water shall not be added to comply with effluent requirements to achieve BCT, BPT, BAT and or other technology-based effluent limitations such as those in State of Tennessee Rule 1200-4-5-.03.

5. Treatment Facility Failure

The permittee, in order to maintain compliance with this permit, shall control production, all discharges, or both, upon reduction, loss, or failure of the treatment facility, until the facility is restored or an alternative method of treatment is provided. This requirement applies in such situations as the reduction, loss, or failure of the primary source of power.

6. Property Rights

The issuance of this permit does not convey any property rights in either real or personal property, or any exclusive privileges, nor does it authorize any injury to private property or any invasion of personal rights, nor any infringement of Federal, State, or local laws or regulations.

7. Severability

The provisions of this permit are severable. If any provision of this permit due to any circumstance, is held invalid, then the application of such provision to other circumstances and to the remainder of this permit shall not be affected thereby.

8. Other Information

If the permittee becomes aware that he failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application or in any report to the Director, then he shall promptly submit such facts or information.

B. CHANGES AFFECTING THE PERMIT

1. Planned Changes

The permittee shall give notice to the Director as soon as possible of any planned physical alterations or additions to the permitted facility. Notice is required only when:

a. The alteration or addition to a permitted facility may meet one of the criteria for determining whether a facility is a new source in 40 CFR 122.29(b); or

b. The alteration or addition could significantly change the nature or increase the quantity of pollutants discharged. This notification applies to pollutants which are subject neither to effluent limitations in the permit, nor to notification requirements under 40 CFR 122.42(a) (1).

2. Permit Modification, Revocation, or Termination

a. This permit may be modified, revoked and reissued, or terminated for cause as described in 40 CFR 122.62 and 122.64, Federal Register, Volume 49, No. 188 (Wednesday, September 26, 1984), as amended.

b. The permittee shall furnish to the Director, within a reasonable time, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The permittee shall also furnish to the Director, upon request, copies of records required to be kept by this permit.

c. If any applicable effluent standard or prohibition (including any schedule of compliance specified in such effluent standard or prohibition) is established for any toxic pollutant under Section 307(a) of the Federal Water Pollution Control Act, as amended, the Director shall modify or revoke and reissue the permit to conform to the prohibition or to the effluent standard, providing that the effluent standard is more stringent than the limitation in the permit on the toxic pollutant. The permittee shall comply with these effluent standards or prohibitions within the time provided in the regulations that establish these standards or prohibitions, even if the permit has not yet been modified or revoked and reissued to incorporate the requirement.

d. The filing of a request by the permittee for a modification, revocation, reissuance, termination, or notification of planned changes or anticipated noncompliance does not halt any permit condition.

3. Change of Ownership

This permit may be transferred to another party (provided there are neither modifications to the facility or its operations, nor any other changes which might affect the permit limits and conditions contained in the permit) by the permittee if:

a. The permittee notifies the Director of the proposed transfer at least 30 days in advance of the proposed transfer date;

b. The notice includes a written agreement between the existing and new permittee's containing a specified date for transfer of permit responsibility, coverage, and liability between them; and

c. The Director, within 30 days, does not notify the current permittee and the new permittee of his intent to modify, revoke or reissue, or terminate the permit and to require that a new application be filed rather than agreeing to the transfer of the permit.

Pursuant to the requirements of 40 CFR 122.61, concerning transfer of ownership, the permittee must provide the following information to the division in their formal notice of intent to transfer ownership: 1) the NPDES permit number of the subject permit; 2) the effective date of the proposed transfer; 3) the name and address of the transferor; 4) the name and address of the transferee; 5) the names of the responsible parties for both the transferor and transferee; 6) a statement that the transferee assumes responsibility for the subject NPDES permit; 7) a statement that the transferor relinquishes responsibility for the subject NPDES permit; 8) the signatures of the responsible parties for both the transferor and transferee pursuant to the requirements of 40 CFR 122.22(a), "Signatories to permit applications"; and, 9) a statement regarding any proposed modifications to the facility, its operations, or any other changes which might affect the permit limits and conditions contained in the permit.

4. Change of Mailing Address

The permittee shall promptly provide to the Director written notice of any change of mailing address. In the absence of such notice the original address of the permittee will be assumed to be correct.

C. NONCOMPLIANCE

1. Effect of Noncompliance

All discharges shall be consistent with the terms and conditions of this permit. Any permit noncompliance constitutes a violation of applicable State and Federal laws and is grounds for enforcement action permit termination, permit modification, or denial of permit reissuance.

2. Reporting of Noncompliance

a. 24-Hour Reporting

In the case of any noncompliance which could cause a threat to public drinking supplies, or any other discharge which could constitute a threat to human health or the environment, the required notice of non-compliance shall be provided to the Division of Water Pollution Control in the appropriate Environmental Assistance Center within 24-hours from the time the permittee becomes aware of the circumstances. (The Environmental Assistance Center should be contacted for names and phone numbers of environmental response personnel).

A written submission must be provided within five days of the time the permittee becomes aware of the circumstances unless this requirement is waived by the Director on a case-by-case basis. The permittee shall provide the Director with the following information:

i. A description of the discharge and cause of noncompliance;

ii. The period of noncompliance, including exact dates and times or, if not corrected, the anticipated time the noncompliance is expected to continue; and

iii. The steps being taken to reduce, eliminate, and prevent recurrence of the noncomplying discharge.

b. Scheduled Reporting

For instances of noncompliance which are not reported under subparagraph 2.a. above, the permittee shall report the noncompliance on the Discharge Monitoring Report. The report shall contain all information concerning the steps taken, or planned, to reduce, eliminate, and prevent recurrence of the violation and the anticipated time the violation is expected to continue.

3. Overflow

a. "***Overflow***" means the discharge to land or water of wastes from any portion of the collection, transmission, or treatment system other than through permitted outfalls.

b. Overflows are prohibited.

c. The permittee shall operate the collection system so as to avoid overflows. No new or additional flows shall be added upstream of any point in the collection system, which experiences chronic overflows (greater than 5 events per year) or would otherwise overload any portion of the system.

d. Unless there is specific enforcement action to the contrary, the permittee is relieved of this requirement after: 1) an authorized representative of the Commissioner of the Department of Environment and Conservation has approved an engineering report and construction plans and specifications prepared in accordance with accepted engineering practices for correction of the problem; 2) the correction work is underway; and 3) the cumulative, peak-design, flows potentially added from new connections and line extensions upstream of any chronic overflow point are less than or proportional to the amount of inflow and infiltration removal documented upstream of that point. The inflow and infiltration reduction must be measured by the permittee using practices that are customary in the environmental engineering field and reported in an attachment to a Monthly Operating Report submitted to the local TDEC Environmental Assistance Center. The data measurement period shall be sufficient to account for seasonal rainfall patterns and seasonal groundwater table elevations.

e. In the event that more than five (5) overflows have occurred from a single point in the collection system for reasons that may not warrant the self-imposed moratorium or completion of the actions identified in this paragraph, the permittee may request a meeting with the Division of Water Pollution Control EAC staff to petition for a waiver based on mitigating evidence.

4. Upset

a. "***Upset***" means an exceptional incident in which there is unintentional and temporary noncompliance with technology-based effluent limitations because of factors beyond the reasonable control of the permittee. An upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, or careless or improper operation.

b. An upset shall constitute an affirmative defense to an action brought for noncompliance with such technology-based permit effluent limitations if the permittee demonstrates, through properly signed, contemporaneous operating logs, or other relevant evidence that:

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

ii. The permitted facility was at the time being operated in a prudent and workman-like manner and in compliance with proper operation and maintenance procedures;

iii. The permittee submitted information required under "Reporting of Noncompliance" within 24-hours of becoming aware of the upset (if this information is provided orally, a written submission must be provided within five days); and

iv. The permittee complied with any remedial measures required under "Adverse Impact."

5. Adverse Impact

The permittee shall take all reasonable steps to minimize any adverse impact to the waters of Tennessee resulting from noncompliance with this permit, including such accelerated or additional monitoring as necessary to determine the nature and impact of the noncomplying discharge. It shall not be a defense for the permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

6. Bypass

a. "***Bypass***" is the intentional diversion of wastewater away from any portion of a treatment facility. "Severe property damage" means substantial physical damage to property, damage to the treatment facilities, which would cause them to become inoperable, or substantial and permanent loss of natural resources, which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in production.

b. Bypasses are prohibited unless the following 3 conditions are met:

i. The bypass is unavoidable to prevent loss of life, personal injury, or severe property damage;

ii. There are not feasible alternatives to bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment down time. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass, which occurred during normal periods of equipment down time or preventative maintenance;

iii. The permittee submits notice of an unanticipated bypass to the Division of Water Pollution Control in the appropriate environmental assistance center within 24-hours of becoming aware of the bypass (if this information is provided orally, a written submission must be provided within five days). When the need for the bypass is foreseeable, prior notification shall be submitted to the Director, if possible, at least 10 days before the date of the bypass.

c. Bypasses not exceeding limitations are allowed **only** if the bypass is necessary for essential maintenance to assure efficient operation. All other bypasses are prohibited. Allowable bypasses not exceeding limitations are not subject to the reporting requirements of 6.b.iii, above.

D. LIABILITIES

1. Civil and Criminal Liability

Except as provided in permit conditions for "**Bypassing,**" "**Overflow,**" and "**Upset,**" nothing in this permit shall be construed to relieve the permittee from civil or criminal penalties for noncompliance. Notwithstanding this permit, the permittee shall remain liable for any damages sustained by the State of Tennessee, including but not limited to fish kills and losses of aquatic life and/or wildlife, as a result of the discharge of wastewater to any surface or subsurface waters. Additionally, notwithstanding this Permit, it shall be the responsibility of the permittee to conduct its wastewater treatment and/or discharge activities in a manner such that public or private nuisances or health hazards will not be created.

2. Liability Under State Law

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable State law or the Federal Water Pollution Control Act, as amended.

PART III

OTHER REQUIREMENTS

A. TOXIC POLLUTANTS

The permittee shall notify the Division of Water Pollution Control as soon as it knows or has reason to believe:

1. That any activity has occurred or will occur which would result in the discharge on a routine or frequent basis, of any toxic substance(s) (listed at 40 CFR 122, Appendix D, Table II and III) which is not limited in the permit, if that discharge will exceed the highest of the following "notification levels":

a. One hundred micrograms per liter (100 ug/l);

b. Two hundred micrograms per liter (200 ug/l) for acrolein and acrylonitrile; five hundred micrograms per liter (500 ug/l) for 2,4-dinitrophenol and for 2-methyl-4,6-dinitrophenol; and one milligram per liter (1 mg/L) for antimony;

c. Five (5) times the maximum concentration value reported for that pollutant(s) in the permit application in accordance with 122.21(g) (7); or

d. The level established by the Director in accordance with 122.44(f).

2. That any activity has occurred or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following "notification levels":

a. Five hundred micrograms per liter (500 ug/l);

b. One milligram per liter (1 mg/L) for antimony;

c. Ten (10) times the maximum concentration value reported for that pollutant in the permit application in accordance with 122.21(g)(7); or

d. The level established by the Director in accordance with 122.44(f).

B. REOPENER CLAUSE

If an applicable standard or limitation is promulgated under Sections 301(b) (2) (C) and (D), 304(B) (2), and 307(a) (2) and that effluent standard or limitation is more stringent than any effluent limitation in the permit or controls a pollutant not limited in the permit, the permit shall be promptly modified or revoked and reissued to conform to that effluent standard or limitation.

C. PLACEMENT OF SIGNS

Within sixty (60) days of the effective date of this permit, the permittee shall place and maintain a sign(s) at each outfall and any bypass/overflow point in the collection system. For the purposes of this requirement, any bypass/overflow point that has discharged five (5) or more times in the last year must be so posted. The sign(s) should be clearly visible to the public from the bank and the receiving stream or from the nearest public property/right-of-way, if applicable. The minimum sign size should be two feet by two feet (2' x 2') with one inch (1") letters. The sign should be made of durable material and have a white background with black letters.

The sign(s) are to provide notice to the public as to the nature of the discharge and, in the case of the permitted outfalls, that the discharge is regulated by the Tennessee Department of Environment and Conservation, Division of Water Pollution Control. The following is given as an example of the minimal amount of information that must be included on the sign:

TREATED INDUSTRIAL WASTEWATER **TVA - Sequoyah Nuclear Plant** **(Permittee's Phone Number)** **NPDES Permit NO. TN0026450** **TENNESSEE DIVISION OF WATER POLLUTION CONTROL** **1-888-891-8332 CHATTANOOGA-ENVIRONMENTAL FIELD OFFICE**

INDUSTRIAL STORM WATER RUNOFF **TVA - Sequoyah Nuclear Plant** **(Permittee's Phone Number)** **NPDES Permit NO. TN0026450** **TENNESSEE DIVISION OF WATER POLLUTION CONTROL** **1-888-891-8332 CHATTANOOGA-ENVIRONMENTAL FIELD OFFICE**

D. ANTIDEGRADATION

Pursuant to the Rules of the Tennessee Department of Environment and Conservation, Chapter 1200-4-3-.06, titled "Tennessee Antidegradation Statement," and in consideration of the Department's directive in attaining the greatest degree of effluent reduction achievable in municipal, industrial, and other wastes, the permittee shall further be required, pursuant to the terms and conditions of this permit, to comply with the effluent limitations and schedules of compliance required to implement applicable water quality standards, to comply with a State Water Quality Plan or other State or Federal laws or regulations, or where practicable, to comply with a standard permitting no discharge of pollutants.

E. BIOMONITORING REQUIREMENTS, CHRONIC

The permittee shall conduct a 3-Brood *Ceriodaphnia dubia* Survival and Reproduction Test and a 7-Day Fathead Minnow *(Pimephales promelas)* Larval Survival and Growth Test on samples of final effluent from Outfall 101. Sampling shall be representative of the discharges made. The permittee shall try to arrange some samples for the biomonitoring testing to coincide with the intermittent application of chemicals so that there are toxicity test results that reflect seasonal variations in chemical treatments.

The measured endpoint for toxicity shall be the inhibition concentration causing 25% reduction (IC25) in survival, reproduction, or growth of the test organisms. The IC25 shall be determined based on a 25% reduction as compared to the controls. The average reproduction and growth responses shall be determined based on the number of Ceriodaphnia dubia or Pimephales promelas larvae used to initiate the test. A separate statistical analysis based on survival information is not required.

Test shall be conducted and its results reported based on appropriate replicates of a total of five serial dilutions and a control, using the percent effluent dilutions as presented in the following table:

Serial Dilutions for Whole Effluent Toxicity (WET) Testing					
100% Effluent	**(100+PL)/2**	**Monitoring Limit (ML)**	**0.50 X ML**	**0.25 X ML**	**Control**
% effluent					
100	**86.4**	**43.2**	**21.6**	**10.8**	**0**

The dilution/control water used will be moderately hard water as described in <u>Short-Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Freshwater Organisms</u>, EPA-821-R-02-013 (or the most current edition). Results from a chronic standard reference toxicant quality assurance test for each species tested shall be submitted with the discharge monitoring report. Reference toxicant tests shall be conducted as required in EPA-821-R-02-013 (or the most current edition). Additionally, the analysis of this multi-concentration test shall include review of the concentration-response relationship to ensure that calculated test results are interpreted appropriately.

Toxicity will be demonstrated if the IC25 is less than the monitoring limit indicated for each outfall in the above table(s). Toxicity demonstrated by the tests specified herein will serve as a hard trigger for accelerated biomonitoring. However, if raw water intake samples (tested concurrently with the effluent samples) are shown to be toxic enough to represent a test failure (100 percent samples statistically less than controls using t-tests and minnow growth or daphnia reproduction is 25 percent less than controls) and if effluent toxicity is not statistically greater than calculated intake toxicity, the effluent toxicity test in question will be considered invalid. In the event these two above described conditions occur, the toxicity test shall be repeated according to the schedule requirements for test failure. Effluent toxicity that is not consistent with the intake toxicity conditions specified above will serve as a hard trigger for accelerated biomonitoring.

All tests will be conducted using a minimum of three 24-hour flow-proportionate composite samples of final effluent (e.g., collected on days 1, 3 and 5). If, in any control more than 20% of the test organisms die in 7 days, the test (control and effluent) is considered invalid and the test shall be repeated within 30 days of the date the initial test is invalidated. Furthermore, if the results do not meet the acceptability criteria of section 4.9.1, EPA-821-R-02-013 (or the most current edition), or if the required concentration-response review fails to yield a valid relationship per guidance contained in Method Guidance and Recommendations for Whole Effluent Toxicity (WET) Testing, EPA-821-B-00-004 (or the most current edition), that test shall be repeated. Any test initiated but terminated before completion must also be reported along with a complete explanation for the termination.

The toxicity tests specified herein for Outfall 101 shall be conducted according to the B/CTP and begin during the first chemical application requiring biomonitoring following the effective date of this permit. WET frequency and results reporting will be governed by the B/CTP. However, in order to effectively track WET monitoring, monthly reporting shall continue. For monitoring periods when WET testing is not required by the approved B/CTP, monitoring not required, or "MNR" shall be reported on the discharge monitoring report (DMR) or electronic report (if being used) to reflect that monitoring is not required.

In the event of a test failure, the permittee must start a follow-up test within 2 weeks and submit results from a follow-up test within 30 days from obtaining initial WET testing results. The follow-up test must be conducted using the same serial dilutions as presented in the corresponding table(s) above. The follow-up test will not negate an initial failed test. In addition, the **failure of a follow-up test will constitute a hard trigger for accelerated biomonitoring, which must also be reported.**

In the event of 2 consecutive test failures or 3 test failures within a 12-month period for the same outfall, the permittee must initiate a Toxicity Identification Evaluation/Toxicity Reduction Evaluation (TIE/TRE) study within 30 days and so notify the division by letter. This notification shall include a schedule of activities for the initial investigation of that outfall. **During the term of the TIE/TRE study, the frequency of biomonitoring shall be once every three months.** Additionally, the permittee shall submit progress reports once every three months throughout the term of the TIE/TRE study. The toxicity must be reduced to allowable limits for that outfall within 2 years of initiation of the TIE/TRE study. Subsequent to the results obtained from the TIE/TRE studies, the permittee may request an extension of the TIE/TRE study period if necessary to conduct further analyses. The final determination of any extension period will be made at the discretion of the division.

The TIE/TRE study may be terminated at any time upon the completion and submission of 2 consecutive tests (for the same outfall) demonstrating compliance. Following the completion of TIE/TRE study, the frequency of monitoring will return to a regular schedule, as defined previously in this section as well in Part I of the permit. **During the course of the TIE/TRE study, the permittee will continue to conduct toxicity testing of the outfall being investigated at the frequency of once every three months but will not be required to perform follow-up tests for that outfall during the period of TIE/TRE study.**

Test procedures, quality assurance practices, determinations of effluent survival/reproduction and survival/growth values, and report formats will be made in accordance with Short-Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Freshwater Organisms, EPA-821-R-02-013, or the most current edition.

Results of all tests, reference toxicant information, copies of raw data sheets, statistical analysis and chemical analyses shall be compiled in a report. The report will be written in accordance with Short-Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Freshwater Organisms, EPA-821-R-02-013, or the most current edition.

Two copies of biomonitoring reports (including follow-up reports) shall be submitted to the division. One copy of the report shall be submitted along with the discharge monitoring report (DMR). The second copy shall be submitted to the local Division of Water Pollution Control office address:

Chattanooga-Environmental Field Office
Division of Water Pollution Control
540 McCallie Avenue, Suite 550
Chattanooga, TN 37402-2013

F. STUDIES RELATED TO EVALUATION OF CWA SECTION 316

Studies as outlined below shall be conducted by the permittee to confirm the performance of the SQN monitoring system and to verify that Section 316 of the Clean Water Act is being adequately met. The data from the studies shall be compiled with past data and reported to the Division of Water Pollution Control with a request for continuation of the thermal variance in the next permit application.

1. <u>Section 316(a)</u>

(*The variance for this requirement will be public noticed with the permit.*)

a. For Section 316(a), the permittee shall analyze previous and new data to determine whether significant changes have occurred in plant operation, reservoir operation or instream biology that would necessitate the need for changes in the thermal variance. The Reservoir Fish Assemblage Index will be used to annually assess the overall health of the fish community in Chickamauga Reservoir. If the fish community or particular populations fall significantly below expectations, further investigations will be proposed, and upon approval by the Division of Water Pollution Control, initiated to verify apparent declines and assist in the identification of possible sources of impairment.

b. To determine the adequacy of the measurement for ambient river temperature, TVA shall conduct field surveys of the river temperature for low river flow, as recommended in TVA Report No. WR2009-1-45-151. Specifically, field surveys shall be conducted if TVA finds it necessary to operate the river in a steady manner below a daily average flow of about 6000 cfs past the plant, or if TVA finds it necessary to operate the river in an unsteady manner below a daily average flow past the plant of about 13000 cfs. This is for operation of both units at SQN. For the operation of one unit at SQN, the limiting river flows for such surveys shall be 3000 cfs and 6500 cfs for steady river flow and unsteady river flow, respectively. Surveys are not required for low flow events where there are no units in operation at SQN. If TVA operates consistently above these levels, no field surveys are required. Also, if an event requires reducing the river flow below these levels without adequate advance notice (e.g., emergency situation), the field surveys should be conducted at the earliest opportunity, in consideration of safe boating conditions and the time required in mobilizing staff and equipment. River flow data to demonstrate compliance to these conditions shall be submitted with the application for re-issuance of the permit. The results of any such surveys, if required, shall be provided to the Division within 90 days of completion of the survey.

c. To determine the adequacy of the diffuser mixing zone, TVA shall conduct field surveys of the river temperature for low river flow, as recommended in TVA Report No. WR2009-1-45-151. Specifically, field surveys shall be conducted if TVA finds it necessary to operate the river in a steady manner below a daily average flow of about 6000 cfs past the plant, or if TVA finds it necessary to operate the river in an unsteady manner below a daily average flow past the plant of about 10000 cfs. This is for operation of both units at SQN. For the operation of one unit at SQN, the limiting river flows for such surveys shall be 3000 cfs and 5000 cfs for steady river flow and unsteady river flow, respectively. Surveys are not required for low flow events where there are no units in operation at SQN. If TVA operates consistently above these levels, no field surveys are required. Also, if an event requires reducing the river flow below these levels without adequate advance notice (e.g., emergency situation), the field surveys should be conducted at the earliest opportunity, in consideration of safe boating conditions and the time required mobilizing staff and equipment. River flow data to demonstrate compliance to these conditions shall be submitted with the application for re-issuance of the permit. The results of any such surveys, if required, shall be provided to the Division within 90 days of completion of the survey.

2. Within 60 days of the permit effective date, the permittee shall prepare and submit for review by the Division a study plan which outlines how the permittee will conduct assessments that will generate information sufficient to support a determination of whether the Sequoyah Nuclear Plant's alternative thermal limit under Section 316(a) can be continued in its next NPDES permit. The proposed study plan shall be designed to supplement information previously provided by the permittee. The permittee shall implement provisions of the plan within 60 days of its approval by the Division.

3. Section 316(b)

   a. Remaining 316(b) requirements for this facility are determined to be in compliance based on best professional judgment in accordance with 40 CFR 401.14 and 122.43. This permit may be reopened to address new 316(b) compliance requirements upon issuance of a new rule or final guidance by EPA.

G. STUDY TO CONFIRM CALIBRATION OF NUMERICAL MODEL

The numerical model used to determine compliance with the temperature requirements for Outfall 101 shall be the subject of a calibration study once during the permit cycle. The study should be accomplished in time for data to be available for the next permit application for re-issuance of the permit. A report of the study will be presented to the Division of Water Pollution Control. Any adjustments to the numerical model to improve its accuracy will not need separate approval from the Division of Water Pollution Control; however, the Division will be notified when such adjustments are made.

The permittee shall calibrate the flow rate characteristics through the diffusers on a schedule of at least once every two years. For this permit period, such calibration shall be coordinated with the evaluation of the numerical modeling.

H. DIESEL FUEL OIL INTERCEPTOR SYSTEM

As previously requested by TVA in February 2006, to close out the monitoring requirements associated with the diesel fuel oil interceptor system; TDEC concurs that the diesel fuel oil recovery project can be terminated. This project has been successful in recovering spilled diesel fuel that leaked out onto the ground. Results from the past two years show results at non-detectable or very low levels. TVA can terminate this recovery project at the end of 2010.

PART IV

STORM WATER POLLUTION PREVENTION PLAN

AND

BIOCIDE/CORROSION TREATMENT PLAN

A. STORM WATER POLLUTION PREVENTION PLAN

Storm water runoff associated with industrial activity that is not discharged to the receiving stream through outfalls permitted in Part I of this permit is currently authorized under the Tennessee Storm Water Multi-Sector General permit for Industrial Activities (TMSP), Permit Number TNR050015. The TMSP requires development, implementation, and routine evaluation and updating of a storm water pollution prevention plan (SWPPP). The permittee shall also ensure that appropriate pollution prevention measures are identified in the SWPPP to minimize the discharge of pollutants in storm water or from ancillary activities via those outfalls described in Part I. Any necessary plan modifications shall be completed in accordance with the schedules set forth in the TMSP.

The discharger will develop, document and maintain a storm water pollution prevention plan (SWPPP) pursuant to the requirements as set forth in the Tennessee Multi-Sector General Permit for Industrial Activities, Sector O, "Storm Water Discharges Associated With Industrial Activity From Steam Electric Power Generating Facilities", Part 3, "Storm Water Pollution Prevention Plan Requirements", as included in the Attachment I of this permit. Also found at: http://www.state.tn.us/environment/wpc/stormh2o/pmt-o.pdf. The plan shall be signed by either a principal executive officer of a corporation, the owner or proprietor of a sole proprietorship, or a partner or general partner of a partnership.

B. BIOCIDE/CORROSION TREATMENT PLAN (B/CTP)

Previous permits addressed biocide and slimicide use at the site for process and non-process flows in the BMP program. A new program for managing the use of these products has been developed under the Biocide/Corrosion Treatment Plan (B/CTP). The permittee shall not conduct treatments of intake or process waters under this permit using biocides, dispersants, surfactants, corrosion inhibiting chemicals, or detoxification chemicals except in accordance with conditions specified under the written B/CTP [plan], which has been given prior approval on April 27, 2005, or subsequent revisions that are approved by the Division of Water Pollution Control. WET frequency and results reporting will be governed by the B/CTP.

C. DOCUMENTATION

The permittee shall maintain the SWPPP and the B/CTP plans at the facility and shall make the plans available to the permit issuing authority upon request.

D. SWPPP-B/CTP PLAN MODIFICATION

The permittee shall amend the SWPPP or B/CTP plan(s) plan whenever there is a change in the facility or change in the operation of the facility that materially increases the potential for the ancillary activities to result in a discharge of significant amounts of pollutants.

E. MODIFICATION FOR INEFFECTIVENESS

If the SWPPP or B/CTP plan(s) prove(s) to be ineffective in achieving the general objective of preventing the release of significant amounts of pollutants to surface waters and the specific objectives and requirements under section B, the permit shall be subject to modification pursuant to 40 CFR 122.62 or 122.63 to incorporate revised SWPPP or B/CTP requirements. Any such permit modification shall be subject to review in accordance with the procedures for permit appeals set forth in accordance with 69-3-110, Tennessee Code Annotated.

F. COMPLIANCE SCHEDULE

The SWPPP and B/CTP plan shall be maintained and the permittee shall begin implementation of any updates of the plan within six (6) months after the effective date of this permit.

ATTACHMENT I

Sector O - Storm Water Discharges Associated With Industrial Activity From Steam Electric Power Generating Facilities, Including Coal Handling Areas

Found at:

http://www.state.tn.us/environment/wpc/stormh2o/pmt-o.pdf

ADDENDUM TO RATIONALE

with

Record of Comments and Responses

National Pollutant Discharge Elimination System

TVA Sequoyah Nuclear Plant, Soddy Daisy, TN

NPDES Permit No. TN0026450

1 February 2011

I. Background and Introduction

On January 27, 2009, the Tennessee Valley Authority (TVA) submitted an application for an NPDES Permit for the discharge of effluent from the Sequoyah Nuclear Plant in Soddy Daisy, TN. The TN Department of Environment and Conservation (TDEC), Division of Water Pollution Control (the division) published a draft permit TN0026450 for the facility on October 11, 2010. Also, the division issued a public notice on the availability of the draft permit for public review and for a public hearing to be held in Chattanooga, TN. The hearing was held on November 10, 2010, and was followed by a comment period through December 10, 2010.

This Addendum to Rationale addresses comments submitted during the public notice period. It also presents TDEC's decision regarding the permit and rationale for that decision.

Comments are shown below with TDECs response and proposed permit changes, as applicable. Written comments are, for the most part, shown verbatim. Lengthy comments have been paraphrased from multiple-page comments which included background and spreadsheets of data. The full length documents are available for review on request. Comments are shown in plain text with **responses shown in bold text.**

II. Administrative Record

This Addendum to Rationale (or fact sheet) dated December, 2010, sets forth the division's basis for permit conditions to be applied for the issuance of the Tennessee NPDES permit for the facility discharge. The permit authorizes a point source discharge to waters of the State of Tennessee from the facility.

On October 14, 2010, the division issued Public Hearing Notice PH10-18, which announced a public hearing, conducted at the TDEC Chattanooga Environmental Field Office in Chattanooga, TN on Wednesday, November 10, 2010, at 6 p.m. (EST).

On October 11, 20109 the division issued Public Notice #MMIX-019, which announced its intent to issue the permit. The draft permit was made available in an electronic format on the division's web site at http://www.state.tn.us/environment/wpc/wpcppo/. The NPDES permit was drafted in accordance with the provisions of the Federal Water Pollution Control Act, the Tennessee Water Quality Control Act, and other applicable standards and regulations.

III. Facility Description

TVA - Sequoyah Nuclear Plant discharges approximately 20 MGD from a retention pond into the Tennessee River at mile 100 via the Diffuser Pond. The plant has two units with a generating capacity of 1,485 megawatts.

IV. Permit History

Permit was last issued in November, 2007, and expired in July 28, 2009 with an administrative extension for current coverage of daily operations at the Sequoyah Nuclear Plant.

This Addendum to Rationale contains all information obtained during the public review of the Draft Permit, including additional comments by the public and reviewing agencies, suggestions and calculations applicable to the proposed discharge.

V. COMMENTS RECEIVED AND RESPONSES

General

Several Commenters suggested changes to the previous Rationale. The Rationale portion of a permit is not edited after public notice has occurred because the Rationale defines the basis for permit conditions at the time of that writing. The Rationale is not legally binding but is an informational document.

Comments suggesting changes to the Permit of a grammatical, typographical, and informational nature are made in the final permit, but are not repeated herein.

Comment 1:

1. Page 1 of 29, Outfall 101 monitoring requirements:

   a. TVA requests that the effluent limits for Total Residual Chlorine (TRC) remain at the current NPDES Permit limit of 0.10 mg/L. Enclosed is a copy of SQN Biocide/Corrosion Treatment Plan Approval and B/CTP Request for Approval submitted to TDEC in March 2005, requesting an NPDES Permit limit of 0.10 mg/L for TRC. TVA's request was based on results from the onsite chlorine demand study which established the method of detection for TRC at 0.08 mg/ L for the SQN site. Also enclosed is a copy of TDEC July 30, 2004, approval for Watts Bar Nuclear's (WBN) Biocide/Corrosion Treatment Plan which established a 0.10 mg/L TRC permit limit for WBN. As previously discussed with your staff, a review of historical samples taken internal to the plant system and calculated for Outfall 101 since 1996 illustrates that the effluent concentrations comply with the allowable water quality based limits.

Response:

TDEC agrees to retain for Outfall 101 the TRC limit of 0.1 mg/l per the previous permit. This limit conforms to previous TDEC approval in 2005 of the B/CTP for both SQN and WBN.

Comment 2:

TVA request that TDEC add for clarification the following information as footnote 1 for Outfall 101. Samples taken in compliance with the monitoring requirements specified above shall be taken as follows:

- Flow - sampled at diffuser gate prior to entry to the Tennessee River;
- Ambient Temperature from Station 14 located at Tennessee River Mile 490.5 upstream of SQN;
- River Temperature - river temperature, temperature rise, and rate of temperature change shall be determined by numerical model.

Response:

Clarification of these sampling locations has been made on Page 2 of 29 for the footnote of Outfall 101 limits table.

Comment 3:

Page 3 of 29, Outfall 101 monitoring requirements: TVA requests that the last paragraph on this page be changed to read as:

Any substance, including radioactive materials, is of interest to our Agency if it has reasonable potential to exceed applicable water quality criteria. However, radioactive releases to the environment, notwithstanding point source discharges authorized via this permit, are not regulated under the Clean Water Act, but are instead **regulated under the Nuclear Regulatory Commission (NRC) by issuance of an Operating License.** Pertinent regulations are found under 10 CFR Part 20 and 10 CFR Part 50. Sequoyah Nuclear Plant effluents that may contain radioactive material are not addressed as part of the NPDES permitting process.

Response: Clarification of monitoring requirements per this comment is added to Page 3 of 29, Outfall 101.

Comment 4: Suggested Changes to Rationale

Response: Because the Rationale establishes the basis for permit conditions at the time of that writing, the Rationale remains unchanged in the administrative record. Subsequent clarifications or comments to the Rationale are addressed in this Addendum as supporting information for issuance of the renewed permit.

Shown below are TDEC clarifications to these suggested changes as it relates to whether changes are made in the permit.

1. Page R-5 of R-43, Outfall 101 monitoring requirements: TVA requests that the last paragraph on this page be changed to read as:

   Any substance, including radioactive materials, is of interest to our Agency if it has reasonable potential to exceed applicable water quality criteria. However, radioactive releases to the environment, notwithstanding point source discharges authorized via this permit, are not regulated under the Clean Water Act, but are instead **regulated under the Nuclear Regulatory Commission (NRC) by issuance of an Operating License.** Pertinent regulations are found under 10 CFR Part 20 and 10 CFR Part 50. Sequoyah Nuclear Plant effluents that may contain radioactive material are not addressed as part of the NPDES permitting process.

See above Response to comment 3.

2. Page R-8 of R-43, Outfall 101 monitoring requirements: TVA requests that the last sentence in Section e. on Polychlorinated Biphenyls (PCB) paragraph be changed to match the permit pages for Outfall 101 and to read as:

   PCB monitoring at Outfall 101 will be deleted from the monitoring requirements.

The permit does not require PCB monitoring at Outfall 101.

3. Page R-8 of R-43, Outfall 101 monitoring requirements: TVA requests that the effluent limits for Total Residual Chlorine (TRC) remain at the current NPDES Permit limit of 0.10 mg/L. As stated on the Rationale page R-8 of R-43, the Lower Limit of Quantification (LLD) for the colorimetric analysis of chlorine using DPD indicator are extremely variable and dependent upon the sample matrix. TVA has performed extensive LLD studies for chlorine analysis using EPA-approved analytical methodologies and associated instrumentation. SQN has determined that the LLD for the Tennessee River in the vicinity of SQN is 0.08 mg/L. TVA had this study independently confirmed by Watts Bar Nuclear Plant. Although the 0.1 mg/L effluent limit will exceed the criterion maximum concentration (CMC), it is recognized that the reported values provided by TVA are calculated value based on TRC measurements taken within a small system prior to mixing with the total cooling water flow. TVA's calculated value only takes into account the mixing with the large volume of non-chlorinated cooling water and does not taken into account the dissipation due to elevated temperatures of the water, sunlight, or turbulence of the water prior to being discharged from Outfall 101. With all of these factors included, TVA is providing a very conservative TRC calculated value for Outfall 101. Therefore, it is anticipated that an effluent limit of 0.10 mg/L for TRC will comply with water quality criteria.

See Comment 101 - The revised permit limit table for Outfall 101 limits TRC to 0.1 mg/L – see page 2 of the permit.

<u>Comment 5 regarding Thermal Variance</u>

After examining the record of prior 316(a) variance determinations for the Sequoyah Plant, EPA has concerns regarding the need for a more thorough examination and definition of the Balanced and Indigenous Population (BIP), the identification of Representative Important Species (RISs), and a closer examination of whether the variance is protective. Given the thinness of the available record for prior variance determinations, EPA believes a more focused study is needed. EPA acknowledges that TVA has in the past collected a substantial amount of data in support of its variance. TVA may use existing data in completing its next study and may incorporate the existence of such data into a CWA Section 316(a) Study Plan design; however, the existing data needs to be evaluated and presented in the context of a BIP definition that the existing record does not adequately provide.

To reiterate, in order to ensure that TVA's Study Plan is adequate to demonstrate that the Sequoyah Plant should get continuance of a Section CWA 316(a) variance during the term of its next NPDES permit, EPA requests the opportunity to review a draft CWA 316(a) study plan prior to TVA commencing the study

<u>Response:</u> The renewed permit requires TVA to submit a Study Plan within 60 days of the permit effective date. TDEC will ensure that EPA review and approval is requested prior to TDEC approval of the Study Plan.

<u>Comment 6:</u>

1. The permit fact should explain the changes in the monitoring location to internal monitoring point 103 for some of the parameters.

<u>Response:</u> Internal Monitoring Point 103 conveys low volume wastes (which are subject to Effluent Limitations Guidelines) into the higher flow diffuser pond which is primarily cooling water. Monitoring for compliance at IMP 003 enables both TDEC and the permittee to document compliance with ELGs prior to significant dilution with cooling water.

<u>Comment 7:</u>

2. The permit fact sheet should better explain the language in the permit regarding justification for eliminating the monitoring for boron.

<u>Response:</u> The draft permit inadvertently included boron in the table of effluent limits for Outfall 101. As noted in the rationale, neither the DMR monitoring data since 2000 nor the analyses submitted with the permit application have detected the presence of boron at the RDL of 0.2 mg/l.

<u>Comment 8:</u>

3. The permit should clarify in item 3 on page 4 that "this permit prohibits the discharge of metal cleaning waste."

AND

5. The fact sheet says that there will be no discharge of metal cleaning waste from internal outfall 103. Therefore, TDEC should delete "Treated Metal Cleaning Waste" from the description for Outfall 103. Otherwise, you will need to include the effluent guideline limits for metal cleaning waste.

<u>Response:</u> In the permit, the description atop the table with effluent limits has been revised to delete Metal cleaning wastes.

<u>Comment 9:</u>

4. The reasonable potential analyses should done for all metals.

<u>Response:</u> The permit application indicated detectable concentrations in Outfall 101 for the following metals (for which TN has relevant water quality criteria): arsenic, copper, mercury. A revised spreadsheet for reasonable potential analysis is attached to this Addendum.

WATER QUALITY BASED EFFLUENT CALCULATIONS
OUTFALL 101

FACILITY: Sequoyah Neclear Plant
PERMIT #: TN0026450

Stream (1Q10) [MGD]	Stream (30Q5) [MGD]	Waste Flow [MGD]	Ttl. Susp. Solids [mg/l]	Hardness (as CaCO3) [mg/l]	Stream Allocation [%]
3483.0	7740.0	1509.6	10	50	90

	1	2	3	4	5	6	7	8
	Stream	Fish/Aqua. Life		Effluent	Fish & Aquatic Life Water Quality Criteria (1Q20)			
	Bckgrnd.	Water Quality Criteria		Fraction	In-Stream Allowable		Calc. Effluent Concentration	
EFFLUENT CHARACTERISTIC	Conc.	Chronic	Acute	Dissolved	Chronic	Acute	Chronic	Acute
	[ug/l]	[ug/l]	[ug/l]	[Fraction]	[ug/l]	[ug/l]	[ug/l]	[ug/l]
Chlorine (T. Res.)	0.0	11.0	19.0	1.0	11.0	19.0	**32.74**	**56.55**
Arsenic *	1.350	150	340	1.0	150	340	**443.67**	**1009.21**
Copper **	2.40	4.95	6.99	0.35	14.25	20.12	**37.43**	**54.91**
Mercury, (T) *	0.005	0.770	1.400	1.000	0.770	1.400	**2.28**	**4.16**

	9	10	11	12	13	14
	Human Health Water Quality Criteria (30Q2)					
	In-Stream Criteria			Calc. Effluent Concentration		
EFFLUENT CHARACTERISTIC	Organisms	Water/Organism	DWS	Organisms	Water/Organism	DWS
	[ug/l]	[ug/l]	[ug/l]	[ug/l]	[ug/l]	[ug/l]
Chlorine (T. Res.)	NA	NA	NA	**NA**	**NA**	**NA**
Arsenic *	10.0	10.0	10.0	**151**	**151**	**151**
Copper **	NA	NA	NA	**NA**	**NA**	**NA**
Mercury, (T) *	0.051	0.05	2.0	**0.3**	**0.3**	**7.5**

*** Criteria for this criteria is expressed as dissolved.**

** Denotes metals for which Fish & Aquatic Life Criteria are expressed as a function of total hardness.
The Fish & Aquatic Life criteria for this metal are in the dissolved form at laboratory conditions.

NOTE: Water Quality criteria for stream use classifications other than Fish & Aquatic Life are based on the 30Q5 flow.

RATIONALE

TVA - Sequoyah Nuclear Plant
NPDES PERMIT NO. TN0026450
Soddy Daisy, Hamilton County, Tennessee

Permit Writer: Mr. Bob Alexander
September, 2010

I. DISCHARGER

TVA - Sequoyah Nuclear Plant
SB-2A, Sequoyah Access Road, P O BOX 2000
Soddy Daisy, Hamilton County, Tennessee

Contact Person:
Stephanie Howard, Environmental Manager - SQN and WBN
423-843-6700

Nature of Business:
Production of electric power by thermonuclear fission and other associated operations.

SIC Code(s): 4911 (Electric Services)
Industrial Classification: Primary [PRIMARY INDUSTRY CATEGORY means any industry category listed in the NRDC Settlement Agreement (Natural Resources Defense Council v. Train, 8 ERC 2120 [D.D.C. 1976], modified 12 ERC 1833 [D.D.C. 1979]).]
Discharger Rating: Major

II. PERMIT STATUS

NPDES Permit No. TN0026450 issued 11/30/07
NPDES Permit No. TN0026450 expired 07/28/09
Application for Renewal received at:
CH-EFO, 1/29/09; NCO, 2/4/09

<u>Watershed Scheduling</u>

Environmental Field Office: Chattanooga
Primary Longitude: 85-05-14 Primary Latitude: 35-12-35
Hydrocode: 6020001 Watershed Group: 3
Watershed Identification: Tennessee River (Hamilton Co. Except Chattanooga)

Target Watershed Evaluation Date: 2013

III. FACILITY DISCHARGES AND RECEIVING WATERS

TVA - Sequoyah Nuclear Plant discharges process and non-process wastewaters through Outfalls 101, IMP103, IMP107, 110, 116, 117 and 118 to Tennessee River. Appendix 1 summarizes facility discharges and receiving stream information for all outfalls.

The Tennessee Multi-Sector General Storm Water Permit TNR050015 covers storm water discharges associated with industrial activity of this facility. Storm water concerns associated with this facility are covered in this general permit, so they will not be addressed in detail in the individual NPDES permit.

The Chickamauga Reservoir portion of the Tennessee River is considered to be fully supporting all designated uses shown in Appendix 1. Biological data submitted by TVA with the permit application addresses the condition of the fishery in Chickamauga Lake. These data are discussed below as part of the analyses of thermal effects of cooling water discharges.

Flow is regulated in the Tennessee River by upstream operations of Watts Bar Dam at mile 529.9 and, therefore, the TDEC rule at 1200-4-3.05 require application of the minimum critical low flow based on the 1Q10 recurrence interval. The 1Q10 used in the previous permit was 5400 cfs or 3491 MGD.

Information was provided with the permit application addressing changes in TVA Reservoir Operations which were implemented during the previous permit term. These changes were addressed and are summarized in the Reservoir Operations EIS[1], which established:

- Bi-weekly average flow, June through August of 13,000 cfs.
- Bi-weekly average flow, May and September of 7,000 cfs.
- Daily Average flow, October through April of 3,000 cfs.

Updates to the policy are summarized in the TVA letter describing existing operations policies as attached to the permit application[2]. Significant points regarding flow through Chickamauga Dam* are:

- For upstream tributary reservoir flow volume above the minimum operating guide, weekly average minimum flow increases June 1 from 14,000 cfs to 25,000 by August 1.
- From August to Labor Day (1st week of September), weekly average minimum flow is 29,000 cfs.
- For reservoir volume below the guide, weekly average minimum flow from June to August is 13,000 cfs.
- From August to Labor Day, the weekly average minimum flow is 25,000 cfs.

River flows as low as 6,000 cfs in November 2007 are identified in the 2009 TVA Report, which was required by the previous permit 3. This flow value occurred during a record-setting

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[1] TVA, *Programmatic EIS, TVA Reservoir Operations Study, Record of Decision, May 2004,* Appendix A, pg A-5, available at http://www.tva.gov/environment/reports/ros_eis/ros_rod.pdf.

[2] TVA *letter to Stefanie Howard*, SQN, from Charles L. Bach, GM, River Scheduling, TVA River Operations, January 7, 2009.

[3] TVA, *Ambient Temperature and Mixing Zone Studies for Sequoyah Nuclear Plant, WR2009-1-45-151, Prepared by Hopping, Stewart, Montgomery, and Higgins, Knoxville, TN, January 2009.*

drought and is considered by TDEC as comparable to the 1Q10 low flow value used in the previous permit.

* The only significant difference in river flow from Watts Bar Dam and Chickamauga Dam is due to Hiwassee River flow, which is approx. 670 cfs, or 433 MGD.

Note on Radiological Discharges:

Effluent discharges authorized through an NPDES program can not cause condition of pollution, nor a discharge of toxics in toxic amounts can be authorized. Any substance, including radioactive materials, is of interest to our agency if it has reasonable potential to exceed applicable water quality criteria. However, radioactive releases to the environment, notwithstanding point source discharges authorized via this permit, are not regulated under the Clean Water Act, but are instead regulated under the Nuclear Regulatory Commission (NRC) by issuance of an Operating License. Pertinent regulations are found under 10 CFR Part 20 and 10 CFR Part 50. Sequoyah Nuclear Plant effluents that may contain radioactive material are not addressed as part of the NPDES permitting process.

IV. APPLICABLE EFFLUENT LIMITATIONS GUIDELINES

The Standard Industrial Classification (SIC) code for TVA - Sequoyah Nuclear Plant is 4911 (Electric Services). Process wastewater discharged through Outfall 101 is regulated by 40 CFR Part §423.12(b) (3)-BPT, and 40 CFR Part §423.13(d) (1)-BAT. Appendix 2 lists the applicable best available technology (BAT) and best conventional pollution control technology (BCT) effluent limitations guidelines. Certain variances are included in the permit to comply with Section 316(a) of the Clean Water Act.

EPA is currently drafting revised ELGs for steam electric plants and issued a proposed Information Collection Request (ICR) questionaire on March 9, 2010.[4]

- ICR was distributed in mid-2010 to selected fossil plants
- Responses from fossil plants were due in 60 days
- EPA analyses of the data will follow, with draft ELGs planned for 2012
- Final ELGs are planned to be proposed in 2014.

For detailed information and to see the questionaire, see Fact Sheet: Request for Comment on Questionnaire for the Steam Electric Power Generating Effluent Guidelines (February 2010). A relevant excerpt is quoted below:

“Approximately 734 fossil- or nuclear-fueled steam electric plants will be required to complete Parts A and I of the questionnaire. This total includes approximately 495 coal-fired, 9 petroleum coke-fired, 20 oil-fired, 168 gas-fired, 20 nuclear power plants, and 22 combination power plants. […] One or more of these subpopulations will also be required to fill out certain additional detailed sections (for some sections of the questionnaire, the coal-fired respondents will be reduced to a subset of approximately 94 plants).

EPA has determined that the data obtained through the Steam Electric ICR is necessary for EPA to review and revise the ELGs for the steam electric industry. The ICR will obtain information about steam electric power generating industry operations for use in characterizing

[4] 75 FR 10791, March 9, 2010

waste streams and the processes that generate the wastes, environmental data, and the availability and affordability of technologies that may be used to reduce wastewater pollutant discharges associated with this industry. These data will be used to perform **detailed technical and economic analyses** that will support EPA's potential **development of numerical limitations** or best management practices for wastewaters generated by steam electric plants."[5] [emphasis added].

V. PREVIOUS PERMIT LIMITS AND MONITORING REQUIREMENTS

Appendix 3 lists the permit limitations and monitoring requirements as defined in the previous permit.

Previous permit terms related to compliance with CWA Section 316 included submission of biological monitoring data by January 2008. These data were to be collected in accordance with the permittee's Proposal for Information Collection (PIC) plan, developed in 2005 under the 316(b) requirements prior to their suspension by EPA on March 20, 2007.

Additional background and detailed discussion of thermal conditions and permit limits are provided below in Sec. VII New Permit Limits – Outfall 101 Effluent Temperature.

VI. HISTORICAL MONITORING AND INSPECTION

During the previous permit term there were no reported violations of the applicable effluent limitations. Data reported by TVA - Sequoyah Nuclear Plant on Discharge Monitoring Report forms during the previous permit term is summarized in Appendix 4.

Division field personnel performed a recent (2006) Compliance Evaluation Inspection (CEI) at the facility however, no notable issues were revealed.

VII. NEW PERMIT LIMITS AND MONITORING REQUIREMENTS

The proposed new permit limits have been selected by determining technology-based limits, then evaluating whether those limits protect the water quality of the receiving stream. If the technology-based limit would cause violations of water quality, then the water quality-based limit is chosen. The technology-based limit is determined from EPA effluent limitations guidelines if applicable (see Part IV); or from State of Tennessee effluent limits for effluent limited segments per Rule 1200-4-5-.03(2); or by way of operational and/or treatability data.

Note that in general, the term "anti-backsliding" refers to a statutory provision that prohibits the renewal, reissuance, or modification of an existing NPDES permit that contains effluents limits, permit conditions, or standards that are less stringent than those established in the previous permit.

Appendix 5 lists the proposed effluent limitations and monitoring requirements for all outfalls to be included in the new permit.

A. Outfall 101

Outfall 101 is the largest volume discharge from the TVA-SQN facility that is primarily composed of once through cooling waters. It also contains water from internal monitoring points (IMP) 103 and 107, and storm water runoff from the site. When the plant is operating in open

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[5] *See* EPA Supporting Statement; *supra* note 8 at 1-2.

mode, the discharge volume will be more than a billion gallons per day. Discharge is by gravity feed to the two diffusers from the diffuser pond. The diffuser pond does not have a significant holding capacity for the discharges and the residence time for water in the pond is relatively short (several hours).

a. Flow

Flow shall be reported in Million Gallons per Day (MGD). Monitoring of flow quantifies the load of pollutants to the stream. The flow shall be continuously monitored and recorded, and reported on the monthly discharge report (DMR).

b. Oil and Grease

The limits for Oil and Grease per 40 CFR 423 (15 mg/l Monthly Average and 20 mg/l Daily Maximum) are applied here to meet the monitoring and compliance standards for low volume wastes. A review of data for Oil and Grease at Outfall101 for the past 14 years shows a maximum of 10.0 mg/L and a median value of < 5.0 mg/L. TVA also monitors Oil and Grease from the Low Volume Waste Pond (IMP103). To comply with antibacksliding provisions, IMP103 will become the primary monitoring and compliance point for Oil & Grease. Oil and Grease monitoring at Outfall101 will be deleted from the permit requirements.

c. Total Suspended Solids (TSS)

The limits for Total Suspended Solids (TSS) per 40 CFR 423 (30 mg/l Monthly Average and 100 mg/l Daily Maximum) are applied here to meet the monitoring and compliance standards for low volume wastes. A review of data for TSS at Outfall101 for the past 14 years shows a maximum of 38.0 mg/L and a median value of 5.0 mg/L. TVA also monitors TSS from the Low Volume Waste Pond (IMP103). To comply with antibacksliding provisions, IMP103 will become the primary monitoring and compliance point for TSS. TSS monitoring at Outfall101 will be deleted from the permit requirements.

d. pH

According to the State of Tennessee Water Quality Standards [Chapter 1200-4-3-.03(3) (b)], the pH for the protection of Fish and Aquatic Life shall lie within the range of 6.5 to 9.0 and shall not fluctuate more than 1.0 unit in this range over a period of 24 hours. A review of data for pH at Outfall101 for the past 14 years shows a maximum of 8.5 S.U. and a median value of 7.6 S.U. TVA also monitors pH from the Low Volume Waste Pond (IMP103). To comply with antibacksliding provisions, IMP103 will become the primary monitoring and compliance point for pH. pH monitoring at Outfall101 will be deleted from the permit requirements. The previous permit limits of 6.0 to 9.0 are retained at IMP103 and were taken from EPA's Effluent Limitation Guidelines 40 CFR Part 423.

e. Polychlorinated Biphenyls

EPA's Effluent Limitation Guidelines in 40 CFR Part 423 requires that there shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid. Therefore, **NO DISCHARGE of PCBs will be allowed**. A review of data for PCB at Outfall101 for the past 11 years shows values below 0.0005 mg/L, which is the Required Detection Level per TDEC rules. PCB monitoring at Outfall101 will be revised to require reporting once per permit cycle by grab sample.

f. Total Residual Chlorine

Technology-based (BAT) limits of 0.2 mg/L monthly average and 0.5 mg/L daily maximum limits apply to free available chlorine in cooling tower blowdown in accordance with 40 CFR, part 423, Subpart 423.13 (b) (1). The total residual chlorine (TRC) test includes all chlorine species measured in the free available chlorine test as well as other chlorine compounds such as chloramines. Thus the permit writer retains the TRC test in place of the free available chlorine test for compliance with the 40 CFR limitations.

Water quality limits of 0.04 mg/L monthly average and 0.06 mg/L daily maximum for total chlorine residual are calculated to protect water quality as shown in Appendix 5a based on the discharge flow of Outfall 101, 1509.6 MGD. The limits are based on the protection of water quality in the Tennessee River to meet published WQC of 0.011 monthly average and 0.019 mg/l daily maximum.

A review of data for TRC values at Outfall101 during the previous permit shows an average concentration of 0.018 mg/L and a maximum of 0.056 mg/L. Accordingly, the renewed permit will establish the monthly average limit of 0.04 mg/L and the daily maximum limit of 0.06 mg/L for Total Residual Chlorine (TRC).

With the permit application, TVA submitted:

> *The Lower Limit of Quantification (LLD) for the colorimetric analysis of chlorine using DPD indicator are extremely variable and dependent upon the sample matrix. Typically, a more pure matrix results in a lower LLD because less interference is present. Instrument manufactures typically report a "best case" LLD in their specification by using a distilled water matrix for LLD determination. However, this LLD cannot be achieved in more complex matrices such as river water due to the presence of organic compounds and color which both negatively impact analytical sensitivity.*
>
> *Sequoyah has performed extensive LLD studies for chlorine analysis using EPA-approved analytical methodologies and associated instrumentation. Sequoyah has determined that the LLD for Tennessee is 0.08 mg/L. This study was independently confirmed by Watts Bar Nuclear Plant.*

The acceptable methods for analysis of TRC are any methods specified in Title 40 CFR, Part 136, as amended. The method detection level (MDL) for TRC shall not exceed 0.08 mg/l, unless the permittee demonstrates that its MDL is higher. The permittee shall retain the documentation that justifies the higher MDL and have it available for review upon request. Under the renewed permit limits, reporting of TRC at less than 0.08 mg/l shall be interpreted to constitute compliance with the permit.

g. Boron, Total (as B)

The division has reviewed the permit application and DMR data submitted since 2000 and has confirmed that Boron is not detected in the effluent. Accordingly, boron monitoring at Outfall101 will be deleted from the permit requirements.

h. Compliance with Section 316, Clean Water Act

1. 316(a) Potential Thermal Effects on a Balanced Indigenous Population

Thermal discharges are a concern for potential effects on a balanced and indigenous population of fish and other aquatic organisms at this location. TVA's extensive studies to date will be further expanded under EPA's guidance during this permit cycle. EPA Region IV has indicated that additional aquatic data should be collected during the five-year duration of the subject permit to facilitate the Section 316(a) determination in the "next NPDES permit." (Permit III.L.) The renewed permit retains the alternative thermal limit as existing data demonstrate the maintenance of a balanced indigenous population ("BIP") in the receiving water body. TVA will be required to submit a study plan outlining proposed assessments to support continuance of the ATL. The plan will be designed to supplement existing information previously provided by TVA. EPA has agreed to this approach and will participate in the review of the plan and the resulting data.

Section 316(a) of the Clean Water Act allows point-source discharges of heated water to exceed State water quality thermal criteria based on demonstrating maintenance of "Balanced Indigenous Populations" (BIP) of aquatic life. SQN is operating under a 316(a) alternate thermal variance that has been administratively continued with each permit renewal based on studies conducted in the 1980's. The requirement for conducting 316(a) studies in TN comes from EPA Region IV guidance to the States requiring future variance requests be granted on new data generated to show aquatic communities meet the BIP standard.

In 2001, TDEC approved the TVA program for Reservoir Fish Assemblies Index (RFAI) studies to support the continuation of thermal variances. RFAI data is collected at upstream and downstream stations in Chickamauga Lake every year. With the application, TVA submitted data from 2000 through 2009 supporting their request for continuation of the 316(a) variance from the previous permit.

With the permit renewal application of January 2009, TVA described ecological conditions near SQN as monitored at three locations under their Vital Signs (VS) program, inflow, transition and forebay. In addition to the fish community, environmental indicators are measured in the VS program for dissolved oxygen, chlorophyll, sediment quality, and benthic macro-invertebrate community.

TDEC has reviewed the RFAI fish community data for 2000-2009 and identified no substantial difference in the fish community of the Chickamauga Reservoir between fish upstream and downstream of SQN. Fish data for both the upstream and downstream stations were determined similar and meet the BIP standard.

Extensive interagency discussions between TVA, TDEC, and EPA Region 4 have occurred regarding future studies to demonstrate BIP. EPA Region 4 has requested additional information prior to their approval of TDEC renewal of any NPDES permits for steam electric power plants, in order to evaluate the thermal component and protection and propagation of a BIP. EPA and TVA have agreed to revise the existing TVA process for reservoir monitoring in accordance with the following terms:

Within 60 days of the permit effective date, the permittee shall prepare and submit for review by the Division a study plan which outlines how the permittee will conduct assessments that *will generate information sufficient to support a determination of whether the Sequoyah Nuclear Plant's alternative thermal limit under Section 316(a) can be continued in its next NPDES permit. The proposed study plan shall be designed to supplement information previously provided by the permittee. The permittee shall implement provisions of the plan within 60 days of its approval by the Division*

In the renewed permit, TDEC will extend the thermal variance, with the condition that TVA will revise the reservoir monitoring approach acceptable to TDEC and EPA Region 4.

2. Thermal Limits and Monitoring Requirements

This permit requires compliance with TN effluent temperature criteria except for the months of November through March when a variance is allowed for upstream to downstream rise in temperature to be as great as 5 C°. Otherwise, temperature shall be limited according to the State of Tennessee Water Quality Standards for the protection of Fish & Aquatic Life [Chapter 1200-4-3-.03(3) (e)]. It is recognized that the temperature of the cooling water discharge will be greater than the temperature of the water prior to its use for cooling or other purposes. This discharge shall not cause the temperature change in receiving stream to exceed 3°C relative to an upstream control point for the months of April through October. Also, this discharge shall not cause the temperature of receiving stream to exceed 30.5°C (except as a result of natural causes), and this discharge shall not cause the maximum rate of temperature change in receiving stream to exceed 2°C per hour; except as a result of natural causes.

The calculated and measured temperatures of the effluent are reported on the monthly Discharge Monitoring Reports (DMRs). The temperature difference, rate of change, and receiving stream calculated-temperatures, shall also be limited and reported on the DMR's. The measured, reported, temperature of the effluent is not limited as such, and an exceedances of the above mentioned 30.5°C water quality criteria will not be considered a permit violation for measured effluent temperature. **The 30.5°C value applies to the receiving stream, not the effluent.** When background stream temperatures are warm and approach 30.5°C as a result of natural conditions the division understands that the plant is then operated in Helper Mode. Helper Mode is defined as: full operation of one cooling tower and at least three lift pumps per operating unit. The permit maximum of 30.5°C may be exceeded when the instream temperatures exceed 29.4°C and the plant operates in Helper Mode. In no circumstance shall a one-hour average maximum downstream river temperature exceed 33.9°C without consent of the permitting authority. **The division shall be notified by phone, facsimile, and/or electronic mail as soon as possible (within 12-hours of calculating these conditions) should these conditions present themselves.** Compliance with the 30.5°C maximum limit shall be determined from the 24-hour average.

The 24-hour average temperature rise in the receiving stream shall be calculated by taking measurements continuously (continuously is defined as measurements taken in 15 minute or less intervals). The 24-hour average value shall be determined using the current and previous ninety-six 15-minute measurements. Thus, every 15 minutes a 24-hour average value shall be calculated. The maximum of the ninety-six observations generated per day by this procedure shall be the daily maximum temperature rise for that day.

Instream river temperatures shall be averaged every 15 minutes in similar fashion to give a "rolling" 24-hour average. To determine compliance with the instream maximum limit of 30.5°C and the temperature difference between upstream and downstream temperatures, the 24-hour average shall be used.

Tennessee Rule 1200-4-3-.05 applies to temperature monitoring by including protection of the water quality in the mixing zone.

"Mixing Zone - Mixing zone refers to that section of a flowing stream or impounded waters in the immediate vicinity of an outfall where an effluent becomes dispersed and mixed. Such zones shall be restricted in area and length and shall not (i) prevent the free passage of fish or cause aquatic life mortality in the receiving waters; (ii) contain materials in concentrations that exceed recognized acute toxicity levels for biota representative of the aquatic community in the receiving waters; (iii) result in offensive conditions; (iv) produce undesirable aquatic life or result in dominance of a nuisance species; (v) endanger the public health or welfare; or (vi) adversely affect the reasonable and necessary uses of the area; (vii) create a condition of chronic toxicity beyond the edge of the mixing zone; and (viii) adversely affect nursery and spawning areas."

The mixing zone was established in the initial EPA-issued permit (April 1, 1983), and as defined, has been retained in Tennessee's reissuance of the permit. The definition of the mixing zone for the new permit is continued from the previous permit for the discharge at Outfall 101, which encompasses 1500 feet downstream of the diffusers to 275 feet upstream of the diffusers and 750 feet wide. Depth of the mixing zone includes the entire depth of the reservoir on the downstream side of the diffusers. On the upstream side of the diffusers the mixing zone extends in depth from the surface 275 feet upstream of the diffusers to the top of the diffuser pipes. The initial mixing zone also included the intake forebay and diffuser pond when the plant operated in closed mode. The diffuser pond is not recognized as waters of the State, instead is considered part of the treatment system and therefore, is not part of the mixing zone for permit purposes. The intake forebay is recognized as waters of the State, but shall be included in the mixing zone only in circumstances when the plant operates in closed mode. The intake forebay connects to the river through openings at the bottom of the skimmer wall. In closed mode operation relatively little water is coming through the openings in the skimmer wall. Therefore, it makes sense to include the intake forebay in the mixing zone in these circumstances. TVA does not anticipate the operation of the plant in closed mode. However, if such emerges as a serious possibility, the monitoring requirements for the forebay shall be determined by appropriate study at that time.

The mixing zone is needed for two reasons. It allows mixing for the thermal loading of the effluent before water quality criteria must be met. For compliance purposes, it allows a well-defined area to be used for actual instream assessments.

TVA Report No. WR2009-1-45-151, required in the last permit cycle, provided a summary of data and studies that have been performed to validate the adequacy of the ambient temperature measurement and the adequacy of the mixing zone. As a part of this work, the location of the ambient temperature measurement had to be moved upstream from about Tennessee River Mile 484.7 to about Tennessee River Mile 490.5, due to the recirculation of plant effluent that occurs at low river flow. TVA shall continue to evaluate the adequacy of the ambient temperature measurement and the adequacy of the mixing zone, if it found necessary to reduce the river flow below levels summarized in Report No. WR2009-1-45-151.

When both units are operational, the difference between the upstream and downstream temperatures is usually between 3 and 4 Celsius degrees during the winter months. The maximum for data reported since January 2000 was 2.0°C. Since 2000, an instream-maximum temperature greater than 30.5°C has only occurred only during the summer of 2010. In these events, no temperature violations were incurred because the plant was placed in helper mode with the operation of one cooling tower and three lift pumps per operating unit. Under these operating conditions, the maximum instream temperature may exceed 30.5°C. During the drought of 2006-7, the highest reported receiving-stream temperature was less than 30.5° in summer.

Sampling of the effluent flow and temperature shall be continuous and shall be recorded for the DMR.

3. Cooling Water Intake Structure - Section 316(b)

316(b) requirements for this facility are determined to be in compliance based on best professional judgment in accordance with 40 CFR 401.14 and 122.43. As required by the previous permit, TVA submitted biological monitoring data collected in accordance with the permittee's Proposal for Information Collection (PIC) plan as developed under the 316(b) requirements prior to their suspension by EPA on March 20, 2007. This permit may be reopened to address new 316(b) compliance requirements upon issuance of a new rule or final guidance by EPA.

316(b) limitations for this facility are determined to be in compliance based on best professional judgment in accordance with 40 CFR 401.14 and 122.43. This permit may be reopened to address compliance with 316(b) requirements upon issuance of a new rule or final guidance by EPA.

This permit, TN0005410, had been previously issued by EPA under the federal NPDES permit program. In those previous permits the facility was deemed to be in compliance with the Clean Water Act Regulations, Establishing Requirements for Cooling Water Intake Structures at Phase II Existing Facilities. This regulation is also referred to as the “316(b) rule”. Previous and current compliance with the rule have been and continue to be based on best professional judgment (BPJ) in accordance with Title 40 CFR 401.14 and 122.43. In 2007, during review of the draft permit addressing TVA's request for permit modification of the 316(b) language, EPA Region 4 suggested the division add language to the rationale of the permit to better detail the events supporting this modification. As it is still relevant to this permit renewal, we have included background information regarding the 2007 recent Court actions relating to the 316(b) rule:

On February 16, 2004, EPA took final action on regulations governing cooling water intake structures at certain existing power producing facilities under section 316(b) of the Clean Water Act (Phase II rule). 69 FR 41576 (July 9, 2004). The final Phase II rule applies to existing facilities that are point sources that, as their primary activity, both generate and transmit electric power or generate electric power for sale to another entity for transmission; use or propose to use cooling water intake structures with a total design intake flow of 50 MGD or more to withdraw cooling water from waters of the United States; and use at least 25 percent of the water withdrawn exclusively for cooling purposes (see 40 CFR 125.91).

Under the Phase II rule, EPA established performance standards for the reduction of impingement mortality and entrainment (see 40 CFR 125.94). The performance standards consist of ranges of reductions in impingement mortality and/or entrainment. These performance standards were determined to reflect the Best Technology Available (BTA) for minimizing adverse environmental impacts at facilities covered by the Phase II rule.

These regulations were challenged by industry and environmental stakeholders. On judicial review, the Second Circuit decision (Riverkeeper, Inc. v. EPA, 475 F.3d 83, (2d Cir., 2007)) remanded several provisions of the Phase II rule on various grounds. The provisions remanded to EPA include:

- *EPA's determination of the BTA under section 316(b);*
- *The rule's performance standard ranges;*
- *The cost-cost and cost-benefit compliance alternatives;*
- *The Technology Installation and Operation Plan provision;*
- *The restoration provision; and*
- *The ``independent supplier'' provision.*

With several significant provisions of the Phase II rule affected by the decision, and with the need to provide timely direction to Stakeholders about the continuing application of the Phase II rule, EPA's Assistant Administrator for Water issued a memorandum on March 20, 2007, which announced EPA's intention to suspend the Phase II rule. This memorandum also discussed the anticipated issuance of [this] Federal Register suspension document.

The formal suspension of the rule was published in the Federal Register: July 9, 2007 (Volume 72, Number 130)] [Rules and Regulations] [Page 37107-37109], and is available from the Federal Register Online via GPO Access [wais.access.gpo.gov] [DOCID:fr09jy07-3].

Upon notice of the suspension of this rule, TVA requested to modify and remove only the suspended 316(b) requirements previously issued in this and seven (7) other TVA NPDES permits. The division agreed with the TVA request and modified only those requirements specifically suspended by the EPA, specifically the CDS report. All other permit requirements remained in place as enforceable compliance items as previously permitted and were deemed to remain in compliance with the remainder of the Clean Water Act based on BTA and best professional judgment (BPJ). In January, 2009, TVA submitted biological monitoring data collected in accordance with the permittee's Proposal for Information Collection (PIC) plan as developed under the 316(b) requirements prior to their suspension by EPA on March 20, 2007. This and other information will be used to support evaluation of Best Technology Available during permit reissuance in subsequent years.

B. Internal Monitoring Point 103

IMP103 is an internal sampling point representing discharges from the Low Volume Waste Treatment Pond (LVWTP), which includes pressure washing and vehicle washing. Wastewater from the Essential Raw Cooling Water (ERCW) system, the Raw Cooling Water (RCW) system, the Lined Metal Cleaning Waste Pond, and the Turbine Building Sump also discharge into the LVWTP. The diffuser pond discharges pass through the diffusers through Outfall 101, into the Tennessee River. <u>IMP103 will become the primary monitoring and compliance point for low volume waste.</u>

Flow

Flow shall be reported in Million Gallons per Day (MGD) and monitored at the time of sample collection. Monitoring of flow quantifies the load of pollutants to the stream. Flow will be recorded on a totalizer and reported 3 times per week.

Oil and Grease

The limits for oil and grease in the new permit will be required by EPA's Effluent Limitation Guidelines (ELG) 40 CFR Part 423: 15 mg/l Monthly Average, 20 mg/l Daily Maximum. The ELG states: "The quantity of pollutants discharged in the low volume waste sources shall not exceed the quantity determined by multiplying the flow of the low volume waste sources times the concentration listed in the [following] table." However to comply with antibacksliding provisions the previous permit limits will be retained. Sampling will be twice per month by grab sample.

Total Suspended Solids (TSS)

The limits for TSS in the new permit will be required by EPA's Effluent Limitation Guidelines (ELG) 40 CFR Part 423: 30 mg/l Monthly Average, 100 mg/l Daily Maximum. The ELG states: "The quantity of pollutants discharged in the low volume waste sources shall not exceed the quantity determined by multiplying the flow of the low volume waste sources times the concentration listed in the [following] table." However to comply with antibacksliding provisions the previous permit limits will be retained. Sampling will be twice per month by grab sample.

pH

According to the State of Tennessee Water Quality Standards [Chapter 1200-4-3-.03(3) (b)], the pH for the protection of Fish and Aquatic Life shall lie within the range of 6.5 to 9.0 and shall not fluctuate more than 1.0 unit in this range over a period of 24 hours. The previous permit limits of 6.0 to 9.0 will be retained and were derived from EPA's Effluent Limitation Guidelines 40 CFR Part 423. The sample type will be grab and will be measured three times per week.

C. Internal Monitoring Point 107

IMP07 is an internal monitoring point to check compliance with permit limitations for the metal cleaning wastewaters which discharges to the Low Volume Waste Treatment pond (LVWTP). The LVWTP (Outfall 103) then discharges into the Diffuser Pond which discharges through Outfall 101 to the Tennessee River, and is monitored by parameters established for those discharged wastewaters.

The last metal cleaning wastewater discharged into IMP107 was in December 2001. Since that timeframe, IMP107 been discharged approximately 150 times due to rainfall. A review of the monitoring data shows that TSS has averaged 3.5 mg/L since December 2001 with a maximum of 19.0 mg/L. Oil and Grease has averaged < 5.0 mg/L (e.g., detection limit) since December 2001 with a maximum of 6.2 mg/L. Copper has averaged 0.005 mg/L since December 2001 with a maximum of 0.023 mg/L. Iron has averaged 0.312 mg/L since December 2001 with a maximum of 1.0 mg/L on February 12, 2004. pH readings since December 2001 have had a median of 8.4 S.U. with a maximum pH value of 8.9 S.U.

TVA Sequoyah Nuclear Plant is authorized to discharge rain water from the defunct metal cleaning ponds into the Low Volume Waste Treatment Pond, (IMP103) which discharges into the Diffuser Pond (Outfall101). TVA will be allowed to direct rainwater that falls in the now defunct metal cleaning ponds to the Low Volume Waste Treatment Pond without any requirements to monitor the discharge at the defunct metal cleaning ponds (IMP107). TVA will put in place a procedure to ensure that no wastewater will be discharged to the metal cleaning ponds.

D. Outfall 110 [Closed Mode Operations only]

As described in the permit application, a discharge from Outfall 110 occurs only when the power plant operates in closed mode operation, which is infrequent. Operation in closed mode has been precluded because of operational restrictions that happen when the plant is operated in this [closed] mode; discharge from Outfall 110 is not anticipated to occur. Closed mode operation is when condenser-circulating water is cooled in the cooling towers and is then routed, via the cold-water return channel, to the intake forebay. Outfall 110 is a sampling point for water passing from the channel into the forebay. The discharge would consist of non-contact cooling water, including primarily condenser circulating water, the essential raw cooling water, and raw cooling water. Other waters would be from the liquid radwaste system, regeneration wastes from the condensate demineralizer, and steam generator blowdown.

Outfall 110 will be limited with the same permit limitations established for Outfall 101 when operated in closed mode only. If discharge occurs, the permittee will monitor and report on the discharge using the same sampling and analysis protocol(s) established for Outfall 101. When no discharge occurs, the permittee shall report "no discharge" on the Discharge Monitoring Report (DMR).

When the facility operates in closed mode, the mixing zone boundaries change to include the intake forebay. Mixing zone temperature compliance calculations only apply at Outfall 101, temperature will not be limited for Outfall 110 discharges.

E. Outfalls 116 and 117

These discharges result from backwashing wastewater from the screens and strainers of the water intake for Condenser Circulating Water (CCW), (Outfall 116) and the intake for Essential Raw Cooling Water (ERCW) (Outfall 117).

Previous permit conditions did not include numerical limitations or monitoring requirements, instead narrative requirements established that no materials were discharged except material previously present in the intake water, and that there shall be no visible sheen in the discharges.

Based on recurrent reports which do not indicate presence of pollutants in this backwash, monitoring will be <u>deleted</u> from the renewed permit.

F. Outfall 118

This outfall drains the Essential Raw Cooling Water dredge pond. Presently the pond is not in service and discharges small amounts of storm water are coming from its now-vegetated area.

The previous outfall limitations were established for discharges from the pond when it was in service, including limits and monitoring for settleable solids, TSS and dissolved oxygen.

These limits became void after the pond was emptied of dredged water and vegetation established in the pond area.

The permit writer proposes that present permit limits be applied to discharges from the pond, if it is put back into service. Otherwise, no monitoring will be required. When no discharge occurs, the permittee shall report "no discharge" on the Discharge Monitoring Report (DMR).

G. Additional Limitations, Monitoring Requirements and Conditions

In addition to the specific numerical limitations discussed above, there are a number of general requirements that will apply to outfalls 101, 110, 116, 117, and 118 and internal monitoring points IMP 103, and IMP 107. These requirements are discussed as follows:

i. 40 CFR Part 423.12 (b) (2) (BPT) and Part 423.13 (a) (BAT) specify, "There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid." This requirement was in the previous permit and will be retained in the new permit.

ii. 40 CFR Part 423.12 (b) (8) (BPT requirements, non wastewater source specific) states that "Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available chlorine or total residual chlorine at any one time unless the utility can demonstrate to the Regional Administrator or State, if the State has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination."

iii. 40 CFR Part 423.13 (b) (2) (BAT requirements, specific to once through cooling water) also states that for plants with a rated electric generating capacity of 25 or more megawatts that "Total residual chlorine may not be discharged from any single generating unit for more than two hours per day unless the discharger demonstrates to the permitting authority that discharge for more than two hours is required for macroinvertebrate control. Simultaneous multi-unit chlorination is permitted."

iv. 40 CFR Part 423.13 (d) (2) (BAT requirements, specific to cooling tower blowdown) states "Neither free available nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the Regional Administrator or State, if the State has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination."

These requirements are potentially applicable to Outfalls 101 (and Outfall 110 in Closed Mode). Chlorine is not added to the Condenser Circulating Water System (once through cooling water), or to the high-pressure fire protection system, (when flushed), at the Sequoyah Nuclear Plant who's discharge is primarily through Outfall 101. With regard to cooling tower blowdown, TVA has made a demonstration to the Division that the facility cannot operate the cooling towers under these requirements without significant damage to the system potentially jeopardizing operational safety. **These requirements were not in the previous permit and will not be included in the new permit.**

v. 40 CFR Part 423.13 (d) (1), BAT requirements for cooling tower blowdown, establishes monthly average and daily maximum effluent limitations for the 126 Priority Pollutants. The monthly average limit and the daily maximum limit (except for chromium and zinc) is "No Detectable Amount." However, Part 423.13 (d) (3) allows the permitting authority, at its discretion, to utilize engineering calculations which demonstrate that the regulated pollutants are not detectable in the final discharge by analytical methods in 40 CFR Part 136. This requirement is potentially applicable to outfall 101. TVA has provided data that demonstrates that priority pollutants will not be added to the system in quantities that will be detectable in cooling tower blowdown. Also the data provided with the Form 2C permit application indicates that the priority pollutants were not present in detectable amounts. The following general statement will be added to the permit "Priority Pollutants will not be discharged in cooling tower blowdown in amounts that are detectable by analytical methods in 40 CFR Part 136. Monitoring for the Priority Pollutants will not be required."

vi. Bromine products may be used at times in the raw water system. For purposes of measurement of Total Residual Chlorine (TRC) in the permit, analyses shall include residual bromine with the results reported as chlorine. Thus there is no separate test for residual bromine, but one test for situations where combinations of chlorine and bromine are being used.

vii. It is recognized that the permittee must use biocides and corrosion inhibitor products to properly operate the facility. Because the chemicals in these products may be detrimental to fish and aquatic life in the receiving stream, there is a need to evaluate the nature of the chemicals, the dosage to be used, the duration of use, the effluent concentration, and the need for treatment prior to discharge. Previous permits addressed biocide/slimicide and corrosion inhibitor products use at the site for process and non-process flows in the BMP program. A program for managing the use of these products has been developed under the Biocide/Corrosion Treatment Plan (B/CTP). The permittee shall not conduct treatments of intake or process waters under this permit using biocides, dispersants, surfactants, corrosion inhibiting chemicals, or detoxification chemicals except in accordance with conditions specified under the written B/CTP [plan], which has been given prior approval on April 27, 2005 (or other revisions), by the Division of Water Pollution Control. The mechanism to alter these applications is by formally amending the B/CTP.

VIII. Water Quality Based Calculations for METALS AND TOXICS

The primary concern for aquatic toxicity from SQN discharges relates to use of **biocides or oxidizers such as chlorine**. The following procedure is used to calculate the allowable instream concentrations for metals and toxics permit limitations.

1. The most recent background conditions of the receiving stream segment for Outfall 101 were compiled using this information:

    * 1Q10 of receiving stream (3491 MGD)
    * Calcium hardness (measured ambient data (50 mg/L))
    * Total suspended solids (10 mg/l, default)
    * Background metals concentrations (measured ambient data)
    * Other dischargers impacting this segment
    * Downstream water supplies, if applicable

2. The chronic water quality criteria are converted from total recoverable metal at lab conditions to dissolved lab conditions for the following metals: cadmium, copper, lead, nickel and zinc. Then translators are used to convert the dissolved lab conditions to total recoverable metal at ambient conditions.

3. The acute water quality criteria are converted from total recoverable metal at lab conditions to dissolved lab conditions for the following metals: cadmium, copper, lead, nickel, zinc, silver and mercury. Then translators are used to convert the dissolved lab conditions to total recoverable metal at ambient conditions for the following metals: cadmium, copper, lead, nickel, silver and mercury.

4. The chronic criteria for Chromium (T) are given in the total recoverable form and are not converted to a dissolved lab condition or to the total recoverable ambient condition.

5. A standard mass balance equation determines the total allowable concentration (permit limit) for each pollutant. This equation also includes a percent stream allocation of 90%.

The following equations are used to evaluate **water quality protection**:

Eqn: $$Cm = \frac{QsCs + QwCw}{Qs + Qw}$$

where:

Cm = resulting in-stream concentration after mixing
Cw = concentration of pollutant in wastewater
Cs = stream background concentration
Qw = wastewater flow
Qs = stream low flow

to protect water quality:

Eqn: $Cw \leq \frac{(S_A)\,[Cm\,(Qs + Qw) - QsCs]}{Qw}$

where: (S_A) = the percent "Stream Allocation".

FACILITY: Sequoyah Neclear Plant
PERMIT #: TN0026450

Stream (1Q10) [MGD]	Stream (30Q5) [MGD]	Waste Flow [MGD]	Ttl. Susp. Solids [mg/l]	Hardness (as CaCO3) [mg/l]	Stream Allocation [%]
3483.0	7740.0	1509.6	10	50	90

	1	2	3	4	5	6	7	8
	Stream	Fish/Aqua. Life		Effluent	Fish & Aquatic Life Water Quality Criteria (1Q20)			
	Bckgrnd.	Water Quality Criteria		Fraction	In-Stream Allowable		Calc. Effluent Concentration	
EFFLUENT	Conc.	Chronic	Acute	Dissolved	Chronic	Acute	Chronic	Acute
CHARACTERISTIC	[ug/l]	[ug/l]	[ug/l]	[Fraction]	[ug/l]	[ug/l]	[ug/l]	[ug/l]
Chlorine (T. Res.)	0.000	11.000	19.000	1.000	11.000	19.000	**36.4**	**62.8**

	9	10	11	12	13	14
	Human Health Water Quality Criteria (30Q2)					
	In-Stream Criteria			Calc. Effluent Concentration		
EFFLUENT	Organisms	Vater/Organism	DWS	Organisms	Vater/Organism	DWS
CHARACTERISTIC	[ug/l]	[ug/l]	[ug/l]	[ug/l]	[ug/l]	[ug/l]
Chlorine (T. Res.)	NA	NA	NA	**NA**	**NA**	**NA**

NOTE: Water Quality criteria for stream use classifications other than Fish & Aquatic Life are based on the 30Q5 flow.

Calculations for this permit have been made using a standardized worksheet titled "Water Quality Based Effluent Calculations", shown below.

Division policy dictates the following procedures in establishing these permit limits:

1. The critical low flow values are determined using USGS data:

   Fish and Aquatic Life Protection

   7Q10 - Low flow under natural conditions
   1Q10 - Regulated low flow conditions

   Other than Fish and Aquatic Life Protection

   30Q2 - Low flow under natural conditions

2. Fish & Aquatic Life water quality criteria for certain Metals are developed through application of hardness dependent equations. These criteria are combined with

dissolved fraction methodologies in order to formulate the final effluent concentrations.

3. For criteria that are hardness dependent, chronic and acute concentrations are based on a Hardness of 50 mg/L and Total Suspended Solids (TSS) of 10 mg/L unless STORET or Water Supply intake data substantiate a different value. Minimum and maximum limits on the hardness value used for all water quality calculations are 25 mg/L and 400 mg/L respectively.

4. Background concentrations are determined from the Division database, results of sampling obtained from the permittee, and/or obtained from nearby stream sampling data. If this background data is not sufficient, one-half of the chronic "In-stream Allowable" water quality criteria for fish and aquatic life is used. If the measured background concentration is greater than the chronic "In-stream Allowable" water quality criteria, then the measured background concentration is replaced with the chronic "In-stream Allowable" water quality criteria for the purpose of calculating the appropriate effluent limitation (Cw). Under these circumstances, and in the event the "stream allocation" is less than 100%, the calculated chronic effluent limitation for fish and aquatic life should be equal to the chronic "In-stream Allowable" water quality criteria. These guidelines should be strictly followed where the industrial source water is not the receiving stream. Where the industrial source water is the receiving stream, and the measured background concentration is greater than the chronic "In-stream Allowable" water quality criteria, consideration may be given as to the degree to which the permittee should be required to meet the requirements of the water quality criteria in view of the nature and characteristics of the receiving stream.

Each worksheet has fourteen (14) data columns, all of which may not be applicable to any particular characteristic constituent of the discharge. A description of each column is as follows:

Column 1: The "Stream Background" concentrations of the effluent characteristics.

Column 2: The "Chronic" Fish and Aquatic Life Water Quality Criteria. For Cadmium, Copper, Lead, Nickel, and Zinc, this value represents the criteria for the dissolved form at laboratory conditions. The Criteria Continuous Concentration (CCC) is calculated using the equation:

Eqn: $$CCC = (\exp\{ m_C [\ln (\text{stream hardness})] + b_C \}) (CCF)$$

where: CCF = Chronic Conversion Factor

This equation and the appropriate coefficients for each metal are from Tennessee Rule 1200-4-3-.03 and the EPA guidance contained *in The Metals Translator: Guidance For Calculating A Total Recoverable Permit Limit From a Dissolved Criterion* (EPA 823-B-96-007, June 1996). Values for other metals are in the total form and are not hardness dependent; no chronic criteria exist for silver. Published criteria are used for non-metal parameters.

Column 3: The "Acute" Fish and Aquatic Life Water Quality Criteria. For Cadmium, Copper, Lead, Nickel, Silver, and Zinc, this value represents the criteria for the dissolved form at laboratory conditions. The Criteria Maximum Concentration (CMC) is calculated using the equation:

Eqn: $$CMC = (\exp\{ m_A [\ln (\text{stream hardness})] + b_A \}) (ACF)$$

where: ACF = Acute Conversion Factor

This equation and the appropriate coefficients for each metal are from Tennessee Rule 1200-4-3-.03 and the EPA guidance contained in *The Metals Translator: Guidance For Calculating A Total Recoverable Permit Limit From a Dissolved Criterion* (EPA 823-B-96-007, June 1996). Values for other metals are in the total form and are not hardness dependent; no acute criteria exist for Total Chromium. Published criteria are used for non-metal parameters.

Column 4: The "Translator" converts the value for dissolved metal at laboratory conditions (columns 2 & 3) to total recoverable metal at in-stream ambient conditions (columns 5 & 6). This factor is calculated using the linear partition coefficients found in *The Metals Translator: Guidance for Calculating a Total Recoverable Permit Limit from a Dissolved Criterion* (EPA 823-B-96-007, June 1996) and the equation:

Eqn: $$\frac{C_{diss}}{C_{total}} = \frac{1}{1 + \{ [K_{po}] [ss^{(1+a)}] [10^{-6}] \}}$$

where: ss = in-stream suspended solids concentration [mg/l]

Linear partition coefficients for streams are used for unregulated (7Q10) receiving waters, and linear partition coefficients for lakes are used for regulated (1Q10) receiving waters. For those parameters not in the dissolved form in columns 2 & 3 (and all non-metal parameters), a Translator of 1 is used.

Column 5: The "Chronic" Fish and Aquatic Life Water Quality Criteria at in-stream ambient conditions. This criteria is calculated by dividing the value in column 2 by the value in column 4.

Column 6: The "Acute" Fish and Aquatic Life Water Quality Criteria at in-stream ambient conditions. This criteria is calculated by dividing the value in column 3 by the value in column 4.

Column 7: The "Chronic" Calculated Effluent Concentration for the protection of fish and aquatic life. This is the Chronic limit.

Column 8: The "Acute" Calculated Effluent Concentration for the protection of fish and aquatic life. This is the Acute limit.

Column 9: The In-Stream Water Quality Criteria for the protection of Human Health associated with the stream use classification of Organism Consumption (Recreation).

Column 10: The In-Stream Water Quality Criteria for the protection of Human Health associated with the stream use classification of Water and Organism Consumption. These criteria are only to be applied when the stream use classification for the receiving stream includes both "Recreation" and "Domestic Water Supply."

Column 11: The In-Stream Water Quality Criteria for the protection of Human Health associated with the stream use classification of Domestic Water Supply.

Column 12: The Calculated Effluent Concentration associated with Organism Consumption.

Column 13: The Calculated Effluent Concentration associated with Water and Organism Consumption.

Column 14: The Calculated Effluent Concentration associated with Domestic Water Supply.

NOTE: The calculated chronic water quality effluent concentrations from Column 7 should be compared, individually, to the values calculated in Columns 12, 13, and 14 in order to determine the most stringent chronic permit limitations. The calculated acute water quality effluent concentrations from Column 8 should then be compared, individually, to values equal to two (2) times the values presented in Columns 12, 13, and 14 in order to determine the most stringent acute permit limitations. These water quality based limits are compared to any technology based (CFR or Tennessee "Rules") effluent limitations, and/or any previous permit limitations, for final determination of the permit limits. TVA has demonstrated that Priority Pollutants will not be discharged in cooling tower blowdown in amounts that are detectable by analytical methods in 40 CFR Part 136. Monitoring for the Priority Pollutants will not be required.

Storm Water

The Tennessee Multi-Sector General Storm Water Permit (TMSP) No.TNR050015 covers storm water discharges associated with the industrial activity of this facility. Storm water concerns associated with this facility are covered in this general permit, so they will not be addressed in detail in the individual NPDES permit.

Since it is the intent of the division that the permittee institutes a Storm Water Pollution Prevention Plan (SWPPP) in order to minimize the discharge of pollutants from storm water outfalls. It is the opinion of the division that the best method for dealing with potential pollution associated with storm water discharges from the TVA-Sequoyah Nuclear Plant facility is through implementation of an aggressive SWPPP coupled with the TMSP to verify SWPPP discharge monitoring effectiveness.

In order to assist the permittee in the evaluation of the effectiveness of the SWPPP, benchmark values developed for the TMSP for Industrial Activities are provided herein for comparison. These benchmark values (cut-off concentrations) were developed by the EPA and the State of Tennessee and are based on data submitted by similar industries for the development of the multi-sector general storm water permit. The cut-off concentrations are target values and should not be construed to represent permit limits.

Parameters of Concern	Cut-Off Concentration [mg/L]
Total Suspended Solids (TSS)	***200***
Oil & Grease	***15***
Iron, TOTAL	***5.0***
pH (range)	***5.0 - 9.0***

Note: Sample values are from the Tennessee Storm Water Multi-Sector General Permit for Industrial Activities, Rationale, Part III, Table III-A: *Parameter Benchmark Values.*

The new permit will contain a requirement that a Storm Water Pollution Prevention Plan be developed and maintained to regulate storm water runoff. This SWPPP is meant to ensure that runoff from the facility site is not a significant source of pollution to the receiving stream. The discharger will develop, document and maintain the SWPPP pursuant to the requirements as set forth in the Tennessee's Storm Water Multi-Sector General Permit for Industrial Activities, Sector O, "*Storm Water Discharges Associated with Industrial Activity from* Steam Electric Power Generating Facilities, Including Coal Handling Areas", Part 3, "Storm Water Pollution Prevention Plan Requirements", as included in the ATTACHMENT I of this permit also found at http://www.state.tn.us/environment/wpc/stormh2o/pmt-o.pdf. The effectiveness of this SWPPP will be examined by requiring storm water monitoring data be submitted of the combined process/storm water discharges. At that time, should the results so dictate, the division maintains the authority to institute specific numeric limitations for the monitored parameters.

IX. BIOMONITORING REQUIREMENTS, CHRONIC

The discharge of industrial wastewater from Outfall 101 may contain several different pollutants, the combined effect of which has a reasonable potential to be detrimental to fish and aquatic life. The Tennessee Water Quality Standards criteria stipulate that "*The waters shall not contain toxic substances, whether alone or in combination with other substances, which will produce toxic conditions...*".

Where the stream is the source, calculation of toxicity limits follows:

$$\text{Dilution Factor} = \frac{Qs}{Qw}$$

where: **Qw** is a wastewater flow (Qw = 1509 MGD) and **Qs** is a receiving stream low flow (1Q10, estimated at 3491 MGD). Please refer to Appendix 1 for specific details regarding facility discharge and receiving stream.

Therefore, IWC is Instream Waste Concentration and is calculated using the following formula:

$$IWC = \frac{Qw}{Qs} \times 100 = \text{Instream Waste Concentration}$$

$$IWC - \frac{Qw}{Qs} \times 100 - \text{Instream Waste Concentration}$$

Where: IWC $\leq$ 1.0 X IC25; or, INHIBITION CONCENTRATION, 25% $\geq$ IWC

Stream Is Source

Stream Flow	Wastewater Flow	Total Flow
[MGD]	[MGD]	[MGD]
3491	1509	3491

DF	2.3
LC50 >	144.1
IC 25 >	43.2

Specifically:

WET testing will now be required on 43.2% effluent based on new flow data provided with this permit renewal application. Toxicity demonstrated in any of the effluent samples as specified above will serve as a trigger for accelerated monitoring.

The toxicity tests specified herein for Outfall 101 shall be conducted according to the B/CTP and begin during the first chemical application requiring biomonitoring following the effective date of this permit. WET frequency and results reporting will be governed by the B/CTP. However, in order to effectively track WET monitoring, monthly reporting shall continue. For monitoring periods when WET testing is not required by the approved B/CTP, monitoring not required, or "MNR" shall be reported on the discharge monitoring report (DMR) or electronic report (if being used) to reflect that monitoring is not required.

X. OTHER REQUIREMENTS

A. BEST MANAGEMENT PRACTICES

Best management practices are included in the permit. Best management practices will apply to the activity that is likely to cause or contribute to pollution of the state's waters. The best management practices under this permit may be combined into a single document with the storm water pollution prevention plan (SWPPP) required under the TMSP general permit TNR050015 if the permittee wishes.

Liquid radwaste is treated by a Liquid Radwaste System and discharged into the cooling channel. The water discharged is mixed with the cooling water and discharged through Outfall 101. Liquid radwaste treatment is to collect and treat those liquids, which are radioactive or potentially radioactive. The treatment typically includes activated carbon, cation exchange resins and a mixed bed resin. Chemical pollutant concerns are minimal, for this waste. Past data and process knowledge indicate that the effluent requirements for low volume wastes are met for this system. The liquid radwastes will be handled according to the TVA-SQN best management practices (BMP) plan.

Best management practices will be included for toxics and hazardous materials control as well as pollutants defined under the Tennessee Water Quality Control Act. The BMP plan shall also include:

1. Biocide treatments for in-plant systems and an approved mechanism for notification and Division approval that should not delay changes needed to protect both the systems of the facility and all manner of plant and aquatic life in waters of the State. This shall be accomplished by amending the B/CTP, but will not require permit modification.
2. Construction and repairs with potential for pollution contributions that are not routed to an appropriate treatment system.
3. Housekeeping and maintenance standard practices manuals.
4. Minimization of pollutants that could result from the backwash activities at Outfall 116 and Outfall 117.

B. CWA Section 316 APPLICATIONS and STUDIES

Section 316(a) allows temperature variance where balanced populations are being protected. Section 316(b) Rule (September 7, 2004) requires that intake designs be implemented to minimize adverse impacts on the aquatic life. Both of these aspects are addressed in the permit including an evaluation of the mixing zone used in the permit.

C. DISCHARGE MODEL CALIBRATION

Diffuser discharges are modeled and the model results used to determine compliance. The characteristics of the model and discharge situation may vary with time. Therefore, calibration of the diffuser flows and the model will continue to be conducted as in the previous permit.

XI. XIII. ANTIDEGRADATION

Tennessee's Antidegradation Statement is found in the Rules of the Tennessee Department of Environment and Conservation, Chapter 1200-4-3-.06. This statement outlines the criteria for the two types of high quality waters. Outstanding National Resource Waters (ONRWs) are designated by the Water Quality Control Board. Other high quality waters, as identified by the division, are referred to as Exceptional Tennessee Waters. Other surface waters not specifically identified and/or designated as high quality are referred to as Available Conditions Waters. Some available conditions waters may be identified by the division as either not meeting water quality criteria or needing additional water-quality based controls to prevent excursion of criteria for some parameters and conditions and are referred to as Unavailable Conditions Waters for those parameters or conditions.

The division has made a stream tier determination of the receiving waters associated with the subject discharge(s) and has found the receiving stream to be other than a high quality water. Additionally, this water is fully supporting of its designated uses. The Department has maintained, and shall continue to assess, the water quality of the stream to assure that the water quality is adequate to protect the existing uses of the stream fully, and to assure that there shall be achieved the highest statutory and regulatory requirements for all new and existing point sources and all cost-effective and reasonable best management practices for nonpoint source control.

XII. PERMIT DURATION

The proposed limitations meet the requirements of Section 301(b) (2) (A), (C), (D), (E), and (F) of the Clean Water Act as amended. It is the intent of the Division to organize the future issuance and expiration of this particular permit such that other permits located in the same watershed and group within the State of Tennessee will be set for issuance and expiration at the same time. In order to meet the target reissuance date for the Tennessee River (Hamilton Co. Except Chattanooga) watershed and following the directives for the Watershed Management Program initiated in January 1996, the permit will be issued to expire in the year 2013.

APPENDIX 1

OUTFALL 101	
LONGITUDE	LATITUDE
85-05-14	35-12-35

FLOW (MGD)	DISCHARGE SOURCE
1447.0000	Condenser Circulating Water ("Open" mode)
40.4100	Essential Raw Cooling Water (ERCW)
2.1250	Yard Drainage Pond (9.5 Mil Gal)
	(incl. bldg. sumps, misc. air conditioner cooling water
	auxiliary bldg. cooling water, misc. waters, and
	storm water runoff from 186.4 acres of property)
1.1900	Low Volume Waste Treatment Pond
	(10 Mil Gal. Pond; Outfall 103)
1490.7250	TOTAL DISCHARGE*

RECEIVING STREAM DISCHARGE ROUTE			
Tennessee River at mile 483.65			
STREAM LOW	7Q10	1Q10	30Q2
FLOW (CFS) *	6250.000	5400.000	8490.000
(MGD)	4040.6	3491.1	5488.8

STREAM USE CLASSIFICATIONS (WATER QUALITY)				
FISH	RECREATION	IRRIGATION	LW&W	DOMESTIC
X	X	X	X	X
INDUSTRIAL	NAVIGATION			
X	X			

Outfall 101 identifies discharge from the Diffuser Pond to the Tennessee River and is the primary discharge of the facility.
*Note that the total discharge value may differ slightly from the schematic provided with the application, and the number used for other calculations.
The Diffuser Pond receives discharges from IMP 103 and IMP 107.

FACILITY DISCHARGES AND RECEIVING WATERS

OUTFALL 110	
LONGITUDE	LATITUDE
85-05-09	35-13-23

FLOW (MGD)	DISCHARGE SOURCE
1516.252	Condenser circulating water
40.320	Essential raw cooling water
37.1794	Raw cooling water
0.750	Steam generator blowdown
	Liquid radwaste, regeneration wastes from
	condensate demineralizer
1594.5014	TOTAL DISCHARGE

RECEIVING STREAM DISCHARGE ROUTE			
Discharges to intake forebay			
STREAM LOW	7Q10	1Q10	30Q2
FLOW (CFS) *	NA		
(MGD)	NA	0.000	0.000

STREAM USE CLASSIFICATIONS (WATER QUALITY)				
FISH	RECREATION	IRRIGATION	LW&W	DOMESTIC
X	X	X	X	
INDUSTRIAL	NAVIGATION			

Discharge at Outfall 110 would occur if plant operates in "closed" mode, during which time several water systems would discharge via Outfall 110 to the plant's intake forebay. In closed mode operation, water recirculates back to the intake forebay and is pulled back into the plant intakes. Closed mode operation is not used under normal plant operations.

APPENDIX 1 (continued)

FACILITY DISCHARGES AND RECEIVING WATERS

Internal Monitoring Point

OUTFALL 103	
LONGITUDE	LATITUDE

RECEIVING STREAM DISCHARGE ROUTE
Discharge to Diffuser pond (Outfall 101) to the Tennessee River

FLOW (MGD)	DISCHARGE SOURCE
1.1371	Condensate Demineralizer (Con DI)
	demineralizer, turbine, building sump
	and storm water runoff
1.1371	TOTAL DISCHARGE

STREAM LOW FLOW (CFS) *	7Q10	1Q10	30Q2
	NA	NA	NA
(MGD)	0.0	0.0	0.0

STREAM USE CLASSIFICATIONS (WATER QUALITY)				
FISH	RECREATION	IRRIGATION	LW&W	DOMESTIC
X	X	X	X	X
INDUSTRIAL	NAVIGATION			
X				

Treatment: Varies from none to neutralization. Final treatment is provided by sedimentation and oil skimming in a 10 million gallon pond

* Reference: Flow Duration and Low Flows of Tennessee Streams through 1992 by George S. Outlaw and Jess D. Weaver. Water Resources Investigations Report 95-4293 prepared by the U.S. Geological Survey in Cooperation with the Tennessee Department of Environment and Conservation and the Tennessee Valley Authority, Nashville, Tennessee, 1996.

FACILITY DISCHARGES AND RECEIVING WATERS

Internal Monitoring Point

OUTFALL 107	
LONGITUDE	LATITUDE

RECEIVING STREAM DISCHARGE ROUTE
Water is pumps into condenser circulating water channel which drains to the Diffuser Pond (Outfall 101) or is pumped to Low Volume Waste Treatment Pond (Outfall 103) which drains into the Diffuser Pond and hten to the Tennessee River

FLOW (MGD)	DISCHARGE SOURCE
0.0025	Metal cleaning wastewater and storm water
	runoff
0.0025	TOTAL DISCHARGE

STREAM LOW FLOW (CFS) *	7Q10	1Q10	30Q2
	NA	NA	NA
(MGD)	NA	NA	NA

STREAM USE CLASSIFICATIONS (WATER QUALITY)				
FISH	RECREATION	IRRIGATION	LW&W	DOMESTIC
X	X	X	X	X
INDUSTRIAL	NAVIGATION			
X				

Treatment: Sedimentation, neutralization, aeration and chemical precipitation into one-million gallon pond series

* Reference: Flow Duration and Low Flows of Tennessee Streams through 1992 by George S. Outlaw and Jess D. Weaver. Water Resources Investigations Report 95-4293 prepared by the U.S. Geological Survey in Cooperation with the Tennessee Department of Environment and Conservation and the Tennessee Valley Authority, Nashville, Tennessee, 1996.

APPENDIX 1 (continued)

FACILITY DISCHARGES AND RECEIVING WATERS

OUTFALL 116	
LONGITUDE	LATITUDE
85-05-13	35-13-33

FLOW (MGD)	DISCHARGE SOURCE
0.060	Washwater from the
	Condenser Circulating Water Trash Sluice
0.0600	TOTAL DISCHARGE

RECEIVING STREAM DISCHARGE ROUTE
Discharges to an embayment of Chickamauga Reservoir at Tennessee River mile 485.3.

STREAM LOW FLOW (CFS) *	7Q10	1Q10	30Q2
(MGD)	0.0	0.0	0.0

STREAM USE CLASSIFICATIONS (WATER QUALITY)				
FISH	RECREATION	IRRIGATION	LW&W	DOMESTIC
X	X	X	X	X
INDUSTRIAL	NAVIGATION			
X	X			

This is an intermittent discharge from the backwash of debris from screen and strainers of the Condenser Cooling Water system to an embayment of the Tennessee River north of the power plant.

FACILITY DISCHARGES AND RECEIVING WATERS

OUTFALL 117	
LONGITUDE	LATITUDE
85-05-03	35-13-32

FLOW (MGD)	DISCHARGE SOURCE
0.0140	Backwash of the Essential Raw Water
	Intake Screen and Strainer
0.0140	TOTAL DISCHARGE

RECEIVING STREAM DISCHARGE ROUTE
Discharges to Tennessee River at mile 484.9.

STREAM LOW FLOW (CFS) *	7Q10	1Q10	30Q2
(MGD)	0.0	0.0	0.0

STREAM USE CLASSIFICATIONS (WATER QUALITY)				
FISH	RECREATION	IRRIGATION	LW&W	DOMESTIC
X	X	X	X	X
INDUSTRIAL	NAVIGATION			
X	X			

This is an intermittent discharge from the backwash of debris from screen and strainers of the Essential Raw Cooling Water system to the Tennessee River.

APPENDIX 1 (continued)

FACILITY DISCHARGES AND RECEIVING WATERS

OUTFALL 118	
LONGITUDE	LATITUDE
85-05-03	35-13-32

FLOW (MGD)	DISCHARGE SOURCE
n/a	Storm water runoff only, from the inactive
	ERCW dredge pond; no industrial activity present.
0.0000	TOTAL DISCHARGE

RECEIVING STREAM DISCHARGE ROUTE			
Discharges to intake forebay			
STREAM LOW FLOW (CFS) *	7Q10	1Q10	30Q2
(MGD)	0.0	0.0	0.0

STREAM USE CLASSIFICATIONS (WATER QUALITY)				
FISH	RECREATION	IRRIGATION	LW&W	DOMESTIC
X	X	X	X	X
INDUSTRIAL	NAVIGATION			
X	X			

Discharge from the Essential Raw Cooling Water dredge pond is inactive, except for storm water runoff from the vegetated area.
This pond could be used for temporary disposal of sediment dredged from intake channel providing water to the plant. Such dredging would be conducted when there is need to restore the channel depth to acceptable level.

APPENDIX 2

APPLICABLE EFFLUENT LIMITATIONS GUIDELINES

40 CFR PART 423 EFFLUENT LIMITATION GUIDELINES
STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY

EFFLUENT CHARACTERISTIC	Low Volume Waste Sources			
	§423.12(b)(3) - BPT		§423.13 - BAT	
	Average of Daily Values for 30 Consecutive Days	Maximum for Any 1 Day	Average of Daily Values for 30 Consecutive Days	Maximum for Any 1 Day
	[mg/l]	[mg/l]	[mg/l]	[mg/l]
TSS	30.0	100.0	--	--
Oil & Grease	15.0	20.0	--	--
pH	6.0 - 9.0	6.0 - 9.0	--	--

Note: 1. The quantity of pollutants discharged shall not exceed the quantity determined by multiplying the flow of low volume waste sources times the concentration listed. At the permitting authority's discretion, the quantity of pollutant allowed to be discharged may be expressed as a concentration limitation instead of the mass based limitations specified. Concentration limitations shall be those specified above.

2. There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.

APPENDIX 2

APPLICABLE EFFLUENT LIMITATIONS GUIDELINES (continued)

40 CFR PART 423 EFFLUENT LIMITATION GUIDELINES
STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY

	Metal Cleaning Wastes			
	§423.12(b)(5) - BPT		§423.13(e) - BAT	
EFFLUENT CHARACTERISTIC	Average of Daily Values for 30 Consecutive Days [mg/l]	Maximum for Any 1 Day [mg/l]	Average of Daily Values for 30 Consecutive Days [mg/l]	Maximum for Any 1 Day [mg/l]
TSS	30.0	100.0	--	--
Oil & Grease	15.0	20.0	--	--
Copper (T)	1.0	1.0	1.0	1.0
Iron (T)	1.0	1.0	1.0	1.0
pH	6.0 - 9.0	6.0 - 9.0	--	--

* Applicable to chemical metal cleaning wastes.

Note: 1. The quantity of pollutants discharged shall not exceed the quantity determined by multiplying the flow of metal cleaning wastes times the concentration listed. At the permitting authority's discretion, the quantity of pollutant allowed to be discharged may be expressed as a concentration limitation instead of the mass based limitations specified. Concentration limitations shall be those specified above.

2. There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.

3. §423.12 refers to metal cleaning wastes while §423.13 refers to chemical metal cleaning wastes only.

APPENDIX 2

APPLICABLE EFFLUENT LIMITATIONS GUIDELINES (continued)

40 CFR PART 423 EFFLUENT LIMITATION GUIDELINES
STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY

	Once Through Cooling Water			
	§423.12(b)(6) - BPT		§423.13(b) - BAT	
EFFLUENT CHARACTERISTIC	Average Concentration [mg/l]	Maximum Concentration [mg/l]	Average Concentration [mg/l]	Maximum Concentration [mg/l]
Free Available Chlorine	0.2 *	0.5 *	0.2 *	0.5 *
Total Residual Chlorine	--	--	--	0.20 **

* §423.12 is applicable to all plants. §423.13 is applicable to plants with a total rated electric generating capacity of less than 25 megawatts only. Neither free available chlorine nor total residual chlorine may be discharged from any single generating unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the permitting authority that the units in a particular location cannot operate at or below this level of chlorination.

** Plant with a total rated electric generating capacity of 25 or more megawatts only. Total residual chlorine may not be discharged from any single generating unit for more than two hours per day unless the discharger demonstrates to the permitting authority that discharge for more than two hours is required for macroinvertebrate control. Simultaneous multi-unit chlorination is permitted.

Note: 1. The quantity of pollutants discharged shall not exceed the quantity determined by multiplying the flow of once through cooling water times the concentration listed. At the permitting authority's discretion, the quantity of pollutant allowed to be discharged may be expressed as a concentration limitation instead of the mass based limitations specified. Concentration limitations shall be those specified above.

2. There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.

APPENDIX 3

PREVIOUS PERMIT LIMITS

PERMIT LIMITS

OUTFALL 101

Condenser Cooling Water, Essential Raw Cooling Water, Cooling Tower Blowdown, Raw Cooling Water, Low Volume Wastes, Metal Cleaning Waste, Sanitary Wastewater, Miscellaneous Low Volume Wastes, including Various Facilities Drains and Sumps, A/C Condensate, Steam Generator Blowdown, High Pressure Fire Protection water, Regeneration Wastes From Condensate Demineralizer, and Storm Water Runoff

	EFFLUENT LIMITATIONS				MONITORING REQUIREMENTS	
	MONTHLY		DAILY			
EFFLUENT CHARACTERISTIC	AVG. CONC. (mg/l)	AVG. AMNT. (lb/day)	MAX. CONC. (mg/l)	MAX. AMNT. (lb/day)	MSRMNT. FRQNCY.	SAMPLE TYPE
FLOW	–		Report (MGD)		Continuous	Recorder [1]
AMBIENT TEMP.	–		Report (Deg.C)		Continuous	Calculate [2]
RIVER TEMP.	–		30.5 Deg.C		Continuous	Modeled [2]
CHLORINE (Ttl.Res.)	0.036	–	0.0580	–	5/Week	Calculate [2]
PCB's	NO DISCHARGE		NO DISCHARGE		Anuually	Grab
pH	Range 6.0 - 9.0		Range 6.0 - 9.0		1/Week	Grab
OIL AND GREASE	15	–	20	--	1/Week	Grab
TSS	30	–	100	--	1/Week	Grab
IC25	Survival, Reproduction, & Growth in 43.9% Effluent				1/Quarter	Composite [3]

Samples taken in compliance with the monitoring requirements specified above shall be taken as follows: Flow - sampled at diffuser gate prior to entry to the Tennessee River; Ambient Temperature - river side of the plant intake skimmer wall; River Temperature - river temperature , temperature rise, and rate of temperature change shall be determined by numerical model.

[1] Measurements shall be made every 15 minutes at the 1-meter, 1.5-meter, and 2-meter depths and the data transmitted to the plant. Temperatures at the three depths shall be avecaged every 15 minutes to give a temperature at the 1.5 -meterdepth. Both 1-hour and 24-hour averages shall be determined every 15 minutes for the Ambient Temperature and River Temperature (i.e., running averages). The 1-hour average shall be computed by averaging the current value and the previous four 15-minute values. The 24-hour average shall be computed by averaging 15-minute values over 24 hours.

[2] See text below table for further information.

[3] See part III for further description of toxicity tests.

PREVIOUS PERMIT LIMITS AND MONITORING REQUIREMENTS

PERMIT LIMITS

OUTFALL 103
Demineralizer Regeneration from Plant 2 Demineralizer, Turbine Building Sump, Treated Metal Cleaning Waste from Outfall 107 and Storm Water Runoff

EFFLUENT CHARACTERISTIC	EFFLUENT LIMITATIONS				MONITORING REQUIREMENTS	
	MONTHLY		DAILY			
	AVG. CONC. (mg/l)	AVG. AMNT. (lb/day)	MAX. CONC. (mg/l)	MAX. AMNT. (lb/day)	MSRMNT. FRQNCY.	SAMPLE TYPE
FLOW	Report (MGD)		Report (MGD)		Recorder	Totalizer
pH	Range 6.0 - 9.0		Range 6.0 - 9.0		3/Week	Grab
OIL AND GREASE	15	190	20	250	1/Week	Grab
TSS	30	380	100	1250	1/Week	Grab

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s):
Treatment Pond discharge prior to mixing with other waste streams.

Note: In the event that the Turbine Building Sump is discharged directly to the CCW Channel or the yard drainage pond, TSS, Oil and Grease, and pH shall be monitored 5/Week.

(continued)

PERMIT LIMITS

OUTFALL 107
Metal Cleaning Wastewater and Storm Water Runoff

EFFLUENT CHARACTERISTIC	EFFLUENT LIMITATIONS				MONITORING REQUIREMENTS	
	MONTHLY		DAILY			
	AVG. CONC. (mg/l)	AVG. AMNT. (lb/batch)	MAX. CONC. (mg/l)	MAX. AMNT. (lb/batch)	MSRMNT. FRQNCY.	SAMPLE TYPE
FLOW	Report (MGD)		Report (MGD)		1/Day	Calculation
pH	Range 6.0 - 9.0		Range 6.0 - 9.0		1/Day	Grab
OIL AND GREASE	--	--	15	--	1/Day	Grab
TSS	--	--	30	--	1/Day	Composite
COPPER (T)	--	--	1.0	--	1/Day	Composite
IRON (T)	--	--	1.0	--	1/Day	Composite
PHOSPHOROUS (P) [1]	--	--	1.0	--	1/Day	Composite

Metal cleaning waste shall mean any cleaning compounds, rinse waters or any other waterborne residues derived from cleaning any metal process equipment.

Metal cleaning waste shall not be discharged into a pond(s) before all non-metal cleaning liquids have been removed to the extent practical without discharging previously removed solids.

In the event that metal cleaning wastes must be processed and discharged through the liquid radwaste system, the limitations and monitoring requirements above shall apply to the discharge from the liquid radwaste system prior to mixing with the Cooling Tower Blowdown.

There shall be no distinct discharge of floating scum, solids, oil sheen, visible foam, and other floating matter in other than trace amounts.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s):
Discharge from the individual pond(s) prior to mixing with any other waste stream.

[1] Limitations and monitoring requirements shall apply only if phosphorous bearing cleaning solutions are used.

PREVIOUS PERMIT LIMITS AND MONITORING REQUIREMENTS (continued)

PERMIT LIMITS

OUTFALL 110

Condenser Cooling Water, Essential Raw Cooling Water, Raw Cooling Water, Misc.

	EFFLUENT LIMITATIONS				MONITORING REQUIREMENTS	
	MONTHLY		DAILY			
EFFLUENT CHARACTERISTIC	AVG. CONC. (mg/l)	AVG. AMNT. (lb/batch)	MAX. CONC. (mg/l)	MAX. AMNT. (lb/batch)	MSRMNT. FRQNCY.	SAMPLE TYPE
FLOW	Report (MGD)		Report (MGD)		1/Day	Calculation
pH	Range 6.0 - 9.0		Range 6.0 - 9.0		1/Day	Grab
OIL AND GREASE	--	--	15	--	1/Day	Grab
TSS	--	--	30	--	1/Day	Composite
COPPER (T)	--	--	1.0	--	1/Day	Composite
IRON (T)	--	--	1.0	--	1/Day	Composite
PHOSPHOROUS (P) [1]	--	--	1.0	--	1/Day	Composite

Metal cleaning waste shall mean any cleaning compounds, rinse waters or any other waterborne residues derived from cleaning any metal process equipment.

Metal cleaning waste shall not be discharged into a pond(s) before all non-metal cleaning liquids have been removed to the extent practical without discharging previously removed solids.

In the event that metal cleaning wastes must be processed and discharged through the liquid radwaste system, the limitations and monitoring requirements above shall apply to the discharge from the liquid radwaste system prior to mixing with the Cooling Tower Blowdown.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): Discharge from the individual pond(s) prior to mixing with any other waste stream.

[1] Limitations and monitoring requirements shall apply only if phosphorous bearing cleaning solutions are used.

PREVIOUS PERMIT LIMITS AND MONITORING REQUIREMENTS (continued)

PERMIT LIMITS

OUTFALLS 116 and 117

Outfall 116: Backwash from the Intake for Condenser Cooling Water
Outfall 117: Backwash from the Intake for Emergency Raw Cooling Water Screen

These discharges are permitted without chemical monitoring requirements.

There shall be no discharge of floating materials other than those previously present in the intake water.

The discharge shall not have a visible oil sheen.

The discharges shall be under the Best Management Practices to control trash and debris.

PERMIT LIMITS

OUTFALL 118
Settling Pond for Dredged Material from Intake Forebay
(Only applicable when the pond is in service)

	EFFLUENT LIMITATIONS				MONITORING REQUIREMENTS	
	MONTHLY		DAILY			
EFFLUENT CHARACTERISTIC	AVG. CONC. (mg/l)	AVG. AMNT. (lb/batch)	MAX. CONC. (mg/l)	MAX. AMNT. (lb/batch)	MSRMNT. FRQNCY.	SAMPLE TYPE
FLOW	Report (MGD)		Report MGD		1/Batch	Estimate
SETTLEABLE SOLIDS	–	–	1.0 ml/l	–	1/30	Grab [1]
TSS	–	–	100	–	2/7	Grab [1]
Dissolved Oxygen	–	–	2.0 Minimum	–	2/7	Grab [1]

There shall be no discharge of floating scum, solids, oil sheen, visible foam, and other floating matter in other than trace amounts.

Samples taken in compliance with the monitoring requirements specified above shall be taken of a discharge from the settling pond prior to mixing with the Intake Forebay.

[1] Grab samples shall be taken at these frequencies, including a grab sample to be taken immediately proir to termination of the batch discharge.

These effluent limitations and monitoring requirements only apply at times this settling pond contains is in use as settling basin for dredged sediment. Best management practices shall be used to control runoff from the pond. Examples include vegetative cover, silt fences, and/or hay bales.

APPENDIX 4

HISTORICAL MONITORING AND INSPECTION

Outfall 101

PARAMETER	FLOW	TSS	TRC	BORON	PH	TEMP DIFF	TEMP RATE	RIVER TEMP
Units	MGD	mg/l	mg/l	mg/l	SU	deg C	deg C	deg C
Maximum	1787	38	0.056	1.5	8.52	4.8	2	31.3
Minimum	498	1	0	0.2	6.85	-1.1	-2.1	4.9
Average	1509.64	5.42	0.01	0.22		1.61	0.09	19.87
Median	1578	5	0.011	0.2	7.57	1.6	0.1	20.4
Count	3897	674	4133	106	914	3893	3893	3893

Outfall 103

PARAMETER	FLOW	TSS	OIL & GREASE	PH
Units	MGD	mg/l	mg/l	SU
Maximum	3.621	43	11	9.29
Minimum	0	1	5	6.23
Average	1.14	9.87	5.25	
Median	1.146	9	5	7.75
Count	3895	709	722	1809

Outfall 107

PARAMETER	FLOW	TSS	OIL & GREASE	PH	COPPER	IRON
Units	MGD	mg/l	mg/l	SU	mg/l	mg/l
Maximum	0.082	19	6.2	8.99	0.023	1.8
Minimum	0.012	1	5	7.26	0.001	0.03
Average	0.03	3.55	5.03		0.00	0.31
Median	0.032	3	5	8.35	0.002	0.19
Count	163	163	164	165	164	169

APPENDIX 5a

NEW PERMIT LIMITS AND MONITORING REQUIREMENTS

WATER QUALITY BASED EFFLUENT CALCULATIONS

FACILITY: Sequoyah Neclear Plant
PERMIT #: TN0026450

Stream (1Q10) [MGD]	Stream (30Q5) [MGD]	Waste Flow [MGD]	Ttl. Susp. Solids [mg/l]	Hardness (as CaCO3) [mg/l]	Stream Allocation [%]
3483.0	7740.0	1509.6	10	50	90

	1	2	3	4	5	6	7	8
	Stream	Fish/Aqua. Life		Effluent	Fish & Aquatic Life Water Quality Criteria (1Q20)			
	Bckgrnd.	Water Quality Criteria		Fraction	In-Stream Allowable		Calc. Effluent Concentration	
EFFLUENT CHARACTERISTIC	Conc.	Chronic	Acute	Dissolved	Chronic	Acute	Chronic	Acute
	[ug/l]	[ug/l]	[ug/l]	[Fraction]	[ug/l]	[ug/l]	[ug/l]	[ug/l]
Chlorine (T. Res.)	0.000	11.000	19.000	1.000	11.000	19.000	**36.4**	**62.8**

	9	10	11	12	13	14
	Human Health Water Quality Criteria (30Q2)					
	In-Stream Criteria			Calc. Effluent Concentration		
EFFLUENT CHARACTERISTIC	Organisms	Water/Organisms	DWS	Organisms	Water/Organisms	DWS
	[ug/l]	[ug/l]	[ug/l]	[ug/l]	[ug/l]	[ug/l]
Chlorine (T. Res.)	NA	NA	NA	**NA**	**NA**	**NA**

NOTE: Water Quality criteria for stream use classifications other than Fish & Aquatic Life are based on the 30Q5 flow.

APPENDIX 5b

New Permit LIMITS

PERMIT LIMITS

OUTFALL 101

Condenser Circulating Water, Essential Raw Cooling Water, Cooling Tower Blowdown, Raw Cooling Water, Low Volume Wastes, Miscellaneous Low Volume Wastes, including Various Facilities Drains and Sumps, A/C Condensate, Steam Generator Blowdown, High Pressure Fire Protection water, Regeneration Wastes From Condensate Demineralizer, and Storm Water Runoff

	EFFLUENT LIMITATIONS				MONITORING REQUIREMENTS	
	MONTHLY		DAILY			
EFFLUENT CHARACTERISTIC	AVG. CONC. (mg/l)	AVG. AMNT. (lb/day)	MAX. CONC. (mg/l)	MAX. AMNT. (lb/day)	MSRMNT. FRQNCY.	SAMPLE TYPE
FLOW	Report (MGD)		Report (MGD)		Continuous	Recorder [1,2]
AMBIENT TEMP.	--		Report (Deg.C)		Continuous	Calculate [1,2]
RIVER TEMP.	--		Report (Deg.C)		Continuous	Calculate [1,3]
CHLORINE (Ttl.Res.)	0.04	--	0.06	--	5/week	Calculate [4,5]
IC25	Survival, Reproduction, & Growth in 43.2% Effluent				See Permit and Note[2]	Composite [3]

[1] Samples taken in compliance with the monitoring requirements specified above shall be taken as follows: Flow - sampled at diffuser gate prior to entry to the Tennessee River; Ambient Temperature - river side of the plant intake skimmer wall; River Temperature - river temperature , temperature rise, and rate of temperature change shall be determined by numerical model.

[2] See text below table for further information that applies to this outfall (101). WET testing frequency and results reporting will be governed by the B/CTP. However, in order to effectively track WET monitoring monthly reporting shall continue. For monitoring periods when WET testing is not required by the approved B/CTP; monitoring not required, or "MNR" shall be reported on the discharge monitoring report (DMR) or the electronic "report (if being used) to reflect that monitoring is not required.

[3] See part III for further description of toxicity tests.

[4] TRC analyses shall be performed within fifteen (15) minutes of sample collection.

5 The acceptable methods for analysis of TRC are any methods specified in Title 40 CFR, Part 136, as amended. The method detection level (MDL) for TRC shall not exceed 0.08 mg/l, unless the permittee demonstrates that its MDL is higher. The permittee shall retain the documentation that justifies the higher MDL and have it available for review upon request. Under the renewed permit limits, reporting of TRC at less than 0.08 mg/l shall be interpreted to constitute compliance with the permit.

New Permit Limits (continued)

PERMIT LIMITS
OUTFALL 103

This is an Internal Monitoring Point (IMP).
Condensate Demineralizer (CON DI), Turbine Building Sump, Essential Raw Cooling Water, Raw Cooling Water, and Storm Water Runoff

	EFFLUENT LIMITATIONS				MONITORING REQUIREMENTS	
	MONTHLY		DAILY			
EFFLUENT CHARACTERISTIC	AVG. CONC. (mg/L)	AVG. AMNT. (lb/day)	AVG. CONC. (mg/L)	AVG. AMNT. (lb/day)	MSRMNT. FRQNCY.	SAMPLE TYPE
FLOW	Report (MGD)		Report (MGD)		Recorder	Totalizer
pH	Report 6.0 - 9.0		Report 6.0 - 9.0		3 / Week	Grab
Oil & Grease	15	-	20	-	2 / Month	Grab
TSS	30	-	100	-	2 / Month	Grab

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s):

Low Volume Treatment Pond Discharge prior to mixing with other waste streams.

Note: In the event the Turbine Building Sump is discharged directly to the CCW Channel or the Yard Drainage Pond, TSS, Oil & Grease, and pH shall be monitored 5 / Week.

Internal Monitoring Point 107

TVA Sequoyah Nuclear Plant is authorized to discharge rain water from the defunct metal cleaning ponds (IMP107) into the Low Volume Waste Treatment Pond, (IMP103) which discharges into the Diffuser Pond (Outfall101). TVA will be allowed to direct rainwater that falls in the now defunct metal cleaning ponds to the Low Volume Waste Treatment Pond without any requirements to monitor the discharge at the defunct metal cleaning ponds (IMP107). TVA will put in place a procedure to ensure that no wastewater will be discharge to the metal cleaning ponds

New Permit Limits (continued)

PERMIT LIMITS

OUTFALL 110[1]

Condenser Circulating Water, Essential Raw Cooling Water, Cooling Tower Blowndown, Raw Cooling Water,

EFFLUENT CHARACTERISTIC	EFFLUENT LIMITATIONS				MONITORING REQUIREMENTS	
	MONTHLY		DAILY			
	AVG. CONC. (mg/L)	AVG. AMNT. (lb/day)	AVG. CONC. (mg/L)	AVG. AMNT. (lb/day)	MSRMNT. FRQNCY.	SAMPLE TYPE
TEMPERATURE	-	-	38.3°C		1/Day	Multi Grabs 2
CHLORINE (Ttl. Res.)	-	-	0.10	-	1/7 Days	Multi Grabs 2

1 Limitations and monitoring requirements are applicable only during periods of closed-mode operation.
There shall be no distinct discharge of floating scum, solids, oil sheen, visible foam,
and/or other floating matter in other than trace amounts.
Samples taken in compliance with the monitoring requirements specified above shall be taken at
the following location(s): recycled cooling water flow prior to entering the Intake Forebay.
Monitoring frequency shall be increased to 1/Day multiple grab any time the discharge is
occurring and fish distress or fatality is observed in the Intake Forebay.

2 Multiply Grabs shall consist of four grab samples collected during one shift each day.

PERMIT LIMITS

OUTFALL 116 and 117

Outfall 116: Backwash from the Intake of the Condenser Circulating Water

Outfall 117: Backwash from the Intake of the Essential Raw Cooling Water (ERCW) System

There are no effluent limits or monitoring requirements for these discharges.
The discharge shall not have a visible oil sheen and the permittee shall take reasonable steps to prevent the return of materials collected on the screens to the receiving waters in a way that causes an unattractive condition on the receiving waters.

New Permit Limits (continued)

PERMIT LIMITS

OUTFALL 118

Settling Pond for Dredged Material form Intake Forebay and ERCW Pump Pits (Wells)

(Only applicable when the pond is in service.)

EFFLUENT CHARACTERISTIC	EFFLUENT LIMITATIONS				MONITORING REQUIREMENTS	
	MONTHLY		DAILY			
	AVG. CONC. (mg/L)	AVG. AMNT. (lb/day)	AVG. CONC. (mg/L)	AVG. AMNT. (lb/day)	MSRMNT. FRQNCY.	SAMPLE TYPE
FLOW	Report (MGD)*		Report (MGD)*		1/Batch	Estimate
SETTLEABLE SOLIDS	-	-	1.0 ml/L	-	1/30 Days	Grab [1]
TOTAL SUSPENDED SOLIDS	-	-	100	-	2/7 Days	Grab [1]
DISSOLVED OXYGEN	-	-	2.0 Minimum	-	2/7 Days	Grab [1]

There shall be no discharge of floating scum, solids, oil sheen, visible foam, and other floating matter in other than trace amounts. Samples taken in compliance with the monitoring requirements specified above shall be taken of a discharge from the settling pond prior to mixing with the Intake Forebay.

1 Grab samples shall be taken at these frequencies, including a grab sample taken immediately prior to termination of the batch discharge.

These effluent limitations and monitoring requirements only apply at times when this settling pond is in use as a settling basin for dredged sediment. Best Management Practices (BMP) shall be used to control runoff from the pond. Examples include vegetative cover, silt fences, and/or hay bales.

Attachment D

Threatened and Endangered Species Correspondence

Attachment D

Threatened and Endangered Species Correspondence

- Jennings, M. E., U.S. Fish and Wildlife Service to R. Warner, U.S. Fish and Wildlife Service. December 6, 2010.

December 06, 2010

Memorandum

To: Richard Warner, NEPA Coordinator, FWS, Atlanta, GA

From: Mary E. Jennings, Field Supervisor (ES), FWS, Cookeville, TN

Subject: Tennessee Valley Authority, Draft Supplemental Environmental Impact Statement (DEIS) for the Sequoyah Nuclear Plant Units 1 and 2 License Renewal, Hamilton County, Tennessee (ER 10/0950)

We have cursorily reviewed the Environmental Review Distribution Transmittal and the DEIS available at *www.tva.com/environment/reports/sqn-renewal*. The Tennessee Field Office has no substantive comments to offer at this time.

If you have any questions concerning our comments, please contact Steve Alexander of my staff at 931/528-6481 (ext. 210) or via e-mail at *steven_alexander@fws.gov*.

Attachment E

Severe Accident Mitigation Alternatives Analysis

Attachment E

Severe Accident Mitigation Alternatives Analysis

Attachment E contains the following sections.

Table of Contents

List of Tables

List of Acronyms

ACAS	Auxiliary Control Air System
AFW	Auxiliary Feedwater
ARFS	Air Return Fan System
ARV	Atmospheric Relief Valve
ATWS	Anticipated Transient Without Scram
BAT	Boric Acid Tank
BSERF	Bypass Small Early Release Frequency
CCF	Common Cause Failure
CCS	Component Cooling Water System (SQN System Designation)
CCP	Centrifugal Charging Pump
CDF	Core Damage Frequency
CVCS	Chemical and Volume Control System
DG	Diesel Generator
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
ERCW	Emergency Raw Cooling Water
ERG	Emergency Response Guideline
FIVE	Fire Induced Vulnerability Evaluation
FPS	Fire Protection System
HCLPF	High Confidence, Low Probability Failure
HEP	Human Error Probability
HFE	Human Failure Event
HLERF	High-pressure Large Early Release Frequency
HPFP	High Pressure Fire Protection
HRA	Human Reliability Analysis
HVAC	Heating, Ventilation and Air Conditioning
ILERF	Isolation Large Early Release Frequency
IPE	Individual Plant Examination
IPEEE	IPE for External Events
ISLOCA	Inter-System Loss of Coolant Accident
LER	Large Early Release
LERF	Large Early Release Frequency
LLERF	Low-pressure Large Early Release Frequency
LOCA	Loss of Coolant Accident
LOSP	Loss of Offsite Power
MACR	Maximum Averted Cost Risk
MCC	Motor Control Center
MCR	Main Control Room
MD	Motor Driven
MSPI	Mitigating System Performance Indicator
PORV	Power Operated Relief Valve
PRA	Probabilistic Risk Assessment
PWST	Primary Water Storage Tank
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RLE	Review Level Earthquake

RHR	Residual Heat Removal
RRW	Risk Reduction Worth
RWST	Refueling Water Storage Tank
SAMA	Severe Accident Mitigation Alternative
SBO	Station Blackout
SER	Small Early Release
SERF	Small Early Release Frequency
SG	Steam Generator
SGTR	Steam Generator Tube Rupture
SI	Safety Injection
SMA	Seismic Margins Assessment
SQUG	Seismic Qualification Users Group
SW	Service Water
TB	Turbine Building
TDAFW	Turbine Driven Auxiliary Feedwater Pump

ATTACHMENT E.1
EVALUATION OF SQN PRA MODEL

E.1 EVALUATION OF PROBABILISTIC RISK ANALYSIS MODEL

The severe accident risk for Sequoyah Nuclear Plant (SQN) Units 1 and 2 was estimated using each unit's Probabilistic Risk Analysis (PRA) model and a Level 3 model developed using the Version 3.6.0 of the Windows Interface for MACCS2, MELCOR Accident Consequence Code (WinMACCS). The CAFTA code was used to develop the SQN PRA Level 1 and Level 2 models. This document provides the description of SQN PRA levels 1 and 2 analyses, Core Damage Frequency (CDF) uncertainty, Individual Plant Examination of External Events (IPEEE) analyses, and PRA model peer review.

E.1.1 PRA Model – Level 1 Analysis

The PRA model (Level 1 and Level 2) used for the SQN SAMA analysis was the SQN SAMA Model which is based on the most recent internal events risk model for SQN (PRA CAFTA R0). This model is the result of a conversion from a large event tree, small fault tree model quantified with RISKMAN to a small event tree, large fault tree model quantified with CAFTA. Each unit has its own version of this model so that minor differences in plant availability and initiator frequency are addressed.

This model reflects the SQN configuration and design as of November 30, 2009. It uses component failure and unavailability data as of November 30, 2009. Overall results and contribution to CDF by initiator group for Unit 1 and Unit 2 are provided in Table E.1-1 and Table E.1-2.

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

Table E.1-3 provides a listing of Level 1 RRW risk significant events (component failures, operator actions, and initiating events) down to a RRW of 1.005 obtained from the Unit 1 SQN SAMA Model results and correlates each event to the SAMAs that are applicable to it. Table E.1-4 is a similar listing of RRW risk significant events which were obtained from the Unit 2 SQN SAMA Model results.

Table E.1-1 – Unit 1 SQN SAMA Model CDF Results by Major Initiators

Initiating Event Group	Initiator CDF	% CDF
Internal Flooding	1.67E-05	56.32%
Loss of all Component Cooling Water	3.58E-06	12.09%
Stuck Open Safety/Relief Valve	2.33E-06	7.86%
Secondary Side Break Outside of Containment	1.31E-06	4.44%
Losses of Main Feedwater	9.28E-07	3.13%
Reactor Trip	9.17E-07	3.10%
Loss of Train 1A Component Cooling Water	8.98E-07	3.03%
Loss of Instrument Boards	7.35E-07	2.48%
Loss of Offsite Power	6.48E-07	2.19%
Turbine Trip	5.14E-07	1.74%
Small LOCA	3.92E-07	1.32%
Loss of Condenser Vacuum	1.60E-07	0.54%
Loss of RCP	9.32E-08	0.31%
Excessive Main Feedwater	8.44E-08	0.29%
MSIV Closures	6.44E-08	0.22%
Loss of Plant Air	6.17E-08	0.21%
Loss of Vital Battery Boards	5.30E-08	0.18%
Vessel Rupture	2.93E-08	0.10%
Interfacing System LOCA	2.80E-08	0.09%
Medium LOCA	2.55E-08	0.09%
Steam Generator Tube Rupture	2.43E-08	0.08%
Core Power Excursion	1.21E-08	0.04%
Secondary Side Break Inside of Containment	1.09E-08	0.04%
Loss of 6.9kV Boards	8.85E-09	0.03%
Loss of Unit Boards	6.83E-09	0.02%
Large LOCA	5.29E-09	0.02%
Inadvertent Safety Injection	5.01E-09	0.02%
Steam Generator PORV Fails Open	3.41E-09	0.01%
Non-Isolable LOCA	3.04E-09	0.01%
Total	2.96E-05	100.00%
SBO Contribution	3.86E-06	13.04%
ATWS Contribution	4.07E-06	13.73%

Table E.1-2 – Unit 2 SQN SAMA Model CDF Results by Major Initiators

Initiating Event Group	Initiator CDF	% CDF
Internal Flooding	2.33E-05	66.29%
Loss of all Component Cooling Water	3.16E-06	8.99%
Stuck Open Safety/Relief Valve	2.50E-06	7.13%
Secondary Side Break Outside of Containment	1.36E-06	3.88%
Reactor Trip	9.06E-07	2.58%
Loss of Train 2A Component Cooling Water	7.55E-07	2.15%
Losses of Main Feedwater	6.87E-07	1.96%
Loss of Instrument Boards	5.65E-07	1.61%
Turbine Trip	5.05E-07	1.44%
Small LOCA	4.48E-07	1.28%
Loss of Offsite Power	3.89E-07	1.11%
Loss of RCP	9.16E-08	0.26%
Loss of Condenser Vacuum	8.70E-08	0.25%
Excessive Main Feedwater	7.72E-08	0.22%
Loss of Vital Battery Boards	4.69E-08	0.13%
MSIV Closures	4.69E-08	0.13%
Loss of Plant Air	3.90E-08	0.11%
Steam Generator Tube Rupture	3.28E-08	0.09%
Vessel Rupture	2.97E-08	0.08%
Interfacing System LOCA	2.84E-08	0.08%
Medium LOCA	2.58E-08	0.07%
Secondary Side Break Inside of Containment	1.18E-08	0.03%
Core Power Excursion	1.12E-08	0.03%
Loss of 6.9kV Boards	7.19E-09	0.02%
Large LOCA	5.35E-09	0.02%
Inadvertent Safety Injection	4.91E-09	0.01%
Loss of Unit Boards	4.52E-09	0.01%
Steam Generator PORV Fails Open	3.44E-09	0.01%
Non-Isolable LOCA	3.29E-09	0.01%
Total CDF	3.51E-05	
SBO Contribution	3.61E-06	10.28%
ATWS Contribution	4.11E-06	11.70%

Table E.1-3 - Correlation of Unit 1 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
HASE2	4.60E-03	1.264	Trip RCPs on loss of Component Cooling Water	This term represents operator failure to trip the reactor cooling pumps on loss of component cooling water in order to prevent failure of the RCP seals. Phase I SAMAs 59, 61, 154, 155, 156, 157, 260 and 264, to reduce the likelihood of the need to trip RCP pumps have been implemented. Phase II SAMAs 55, 56, 103, 215 and 283 to increase the reliability of seal injection or cooling and increase training and improve awareness of important operator actions have been evaluated.
HARR1	2.40E-02	1.154	Align high pressure recirculation, given auto swapover works	This event represents the failure of operators to align high pressure recirculation given that auto swap over to containment sump has failed. Phase I SAMAs 31 and 36 dealing with alignment of recirculation have been implemented. Phase II SAMAs 32, 103 and 283, evaluated automatic recirculation alignment and increase training and improve awareness of important operator actions have been evaluated.
%1CCSTL	1.00E+00	1.138	UNIT 1 CCSTL INITIATING EVENT IDENTIFIER	This term represents the total loss of component cooling water system initiator. This term is essentially a flag event in the model which always occurs in cutsets containing component cooling water events leading to the total loss of component cooling water and plant trip. Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, 56 and 215 have also been evaluated.
%662.0-1_026_S	2.84E-01	1.133	HPFP SPRAY EVENT IN 662.0-1 - Initiator	This event represents the initiator for a spray event in the Turbine Building which originates from High Pressure Fire Protection system piping. Phase II SAMA 285, to protect equipment in the Turbine Building from internal flooding effects has been evaluated.
%0_ELB_FLOOD	3.57E-06	1.124	ELECTRIC BOARD ROOM FLOODS - Initiator	This event is a combination of individual flooding initiators, all of which either originate in or propagate to both electric board rooms 734.0-A2 and 734.0-A24. As modeled, this initiator results in the loss of all AC power. Phase II SAMA 286 to limit internal flooding propagation between electrical divisions on Auxiliary Building elevation 734.0 has been evaluated.

Table E.1-3 - Correlation of Unit 1 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
U0_CCS02AHUFD_1_2	8.12E-05	1.098	CCF of two components: AHUFD1CLR_0300190 & AHUFD1CLR_0300191	This term represents the common cause failure of CCS and AFW Pump Space Coolers A and B to start on demand. Phase II SAMA 289 to install a backup room cooling train was evaluated.
HAFR1	2.60E-03	1.086	Restore MDAFW LCV control following initiator and loss of air	This event represents the failure of operators to connect nitrogen bottles for AFW level control valves. Phase I SAMA 73, for local manual operation of auxiliary feedwater system, has been implemented. Phase II SAMAs 70, 87, 103, 188, and 283 to improve the reliability of air systems and increase training and awareness of important operator actions have been evaluated.
%1SLOCAL	2.84E-03	1.085	STUCK OPEN SAFETY/RELIEF VALVE	This event represents a stuck open safety/relief valve initiator, which has a plant response similar to that of a small break LOCA. Important actions associated with this initiator are failure to align high pressure recirculation (HARR1) and failure to cooldown and depressurize (AFWOP3). Phase I SAMAs 36, 41 and 42 improve capability for cooldown and depressurization have been implemented. Phase II SAMAs 32, 103 and 283 for automatic recirculation and improved operator training have been evaluated.
ACPFR0CMP_0320086	7.68E-02	1.085	COMPRESSOR B FAILS TO RUN	This term represents the failure of Auxiliary Control Air System compressor B to continue to run. Phase II SAMAs 70, 87, 188 to increase reliability of air systems and coping capability on their loss have been evaluated.
ACPFR0CMP_0320060	7.68E-02	1.084	COMPRESSOR A FAILS TO RUN	This term represents the failure of Auxiliary Control Air System compressor A to continue to run. Phase II SAMAs 70, 87, 188 to increase reliability of air systems and coping capability on their loss have been evaluated.
SHECLR-2	4.40E-03	1.077	Mispositioning ERCW valves, blocking flow to the CCS/AFW and the BAT/AFW space coolers	This term represents the failure of operators properly position ERCW valves following a flush procedure for the CCS, BAT and AFW pump Train B space coolers. This is a pre-initiator event. Phase II SAMA 283 to increase awareness of important human actions has been evaluated.

Table E.1-3 - Correlation of Unit 1 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
HAMARV	1.90E-03	1.076	Handwheel Operation of the Steam Generator Atmospheric Relief Valves S/G 1&4	This term represents the failure of operators to manually open SG atmospheric relief valves in the event of the failure of air and power support systems. Phase I SAMA 40 for remote manual capability of SG PORVs has been implemented. Phase II SAMAs 87, 88, 188 and 283 to increase the reliability of air systems and PORVs, and to increase training and improve awareness of important operator actions have been evaluated.
PTSFD1PMP_0030142	9.38E-03	1.073	Turbine Driven Aux-Feedwater Pump Fails to Start	This event represents the random failure of the turbine driven AFW pump to start. Phase I SAMAs 72, 73, 74 and 223 to improve the reliability of the AFW turbine driven pump have been implemented.
SHECLR-1	4.40E-03	1.071	Mispositioning ERCW valves, blocking flow to the CCS/AFW and the BAT/AFW space coolers	This term represents the failure of operators properly position ERCW valves following a flush procedure for the CCS, BAT and AFW pump Train A space coolers. This is a pre-initiator event. Phase II SAMA 283 to increase awareness of important human actions have been evaluated.
ACPFR_SOK_2	1.37E+00	1.07	ACPFR Stake of Knowledge Factor for a group of 2	This term is a factor used to address the state of knowledge correlation for two air compressors. It is used to adjust the frequency of cutsets which contain two air compressor events. Phase II SAMAs 70, 87, 188 to increase reliability of air systems and coping capability on their loss have been evaluated.
HAFR2	2.20E-03	1.064	Restore TDAFWP speed control following initiator and loss of air	This event represents the failure of operators to restore speed control of the turbine driven AFW pump following loss of air. Phase I SAMA 73 to proceduralize local manual operation of auxiliary feedwater system when control power is lost has been implemented. Phase II SAMAs 103 and 283 to increase training and improve awareness of important operator actions have been evaluated.
HAFR2_FL	5.00E+00	1.063	FLOODING MULTIPLIER HARFR2	This term is used to add an additional stress factor due to flooding on to human failure event HAFR2. Phase II SAMA 279 to improve internal flooding response has been evaluated.

Table E.1-3 - Correlation of Unit 1 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
%690.0-A01-2_026_S	8.31E-03	1.06	HPFP SPRAY EVENT IN 690.0-A1-2 - Initiator	This term represents the initiator for a HPFP spray event in partition 2 of room 690.0-A1 in the Auxiliary Building. Phase II SAMAs 288 and 275 to install spray shields for the component cooling water pumps and CCS pump and AFW pump Space Coolers; install spray shields on the AFW pumps and AFW/BAT Space Coolers have been evaluated.
CBKFO1BKR_0680008	1.34E-03	1.06	SQN-1-BCTA-068-0008 BREAKERS FAILS TO OPEN ON DEMAND FOR RCP 1	This term represents the failure of the Reactor Coolant Pump 1 circuit breakers to open when demanded. Phase I SAMAs 59, 61, 154, 155, 156, 157, 260 and 264, to reduce the likelihood of the need to trip RCP pumps have been implemented. Phase II SAMAs 55, 56, 215 and 218 have also been evaluated.
CBKFO1BKR_0680031	1.34E-03	1.06	SQN-1-BCTA-068-0031 BREAKERS FAILS TO OPEN ON DEMAND FOR RCP 2	This term represents the failure of the Reactor Coolant Pump 2 circuit breakers to open when demanded. Phase I SAMAs 59, 61, 154, 155, 156, 157, 260 and 264, to reduce the likelihood of the need to trip RCP pumps have been implemented. Phase II SAMAs 55, 56, 215, and 218 have also been evaluated.
CBKFO1BKR_0680050	1.34E-03	1.06	SQN-1-BCTA-068-0050 BREAKERS FAILS TO OPEN ON DEMAND FOR RCP 3	This term represents the failure of the Reactor Coolant Pump 3 circuit breakers to open when demanded. Phase I SAMAs 59, 61, 154, 155, 156, 157, 260 and 264, to reduce the likelihood of the need to trip RCP pumps have been implemented. Phase II SAMAs 55, 56, 215 and 218 have also been evaluated.
CBKFO1BKR_0680073	1.34E-03	1.06	SQN-1-BCTA-068-0073 BREAKERS FAILS TO OPEN ON DEMAND FOR RCP 4	This term represents the failure of the Reactor Coolant Pump 4 circuit breakers to open when demanded. Phase I SAMAs 59, 61, 154, 155, 156, 157, 260 and 264, to reduce the likelihood of the need to trip RCP pumps have been implemented. Phase II SAMAs 55, 56, 215 and 218 have also been evaluated.
COMBINATION_1593	4.22E+02	1.048	HEP dependency factor for HAFR2,HARR1,HAFR1	This term is a factor that accounts for the dependency between multiple human failure events (HAFR2, HARR1, HAFR1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.

Table E.1-3 - Correlation of Unit 1 Level 1 Risk Significant Terms to SAMAs (Based on CDF)				
Event Name	**Probability**	**RRW**	**Event Description**	**Disposition**
HAOB2	5.60E-03	1.045	Establish RCS Bleed and Feed cooling given no CCPs running	This term represents the failure of operators to establish feed and bleed operation given that chemical and volume control pumps are available. (Basic Event name in model is not accurate.) Phase II SAMAs 103 and 283 to increase training and improve awareness of important operator actions have been evaluated.
AHUFD1CLR_0300191	2.23E-03	1.038	CCS PUMPS AND AFW PUMPS SPACE COOLER B FAILS TO START ON DEMAND	This event represents the failure of the CCS Pumps and AFW Pumps "B" area cooler to start. Phase II SAMA 289 to install a backup train of room cooling has been evaluated.
AFWOP3	4.10E-03	1.037	Depressurize/cooldown to LP injection after a small or medium LOCA with failure of HP recirculation	This term represents the failure of operators to depressurize and cooldown vessel so that low pressure injection can be used following a small or medium LOCA with failure of high pressure recirculation. Phase I SAMAs 36, 41 and 42 improve capability for cooldown and depressurization have been implemented.
HARR1_FL	5.00E+00	1.037	FLOODING MULTIPLIER FOR HARR1	This term is used to add a stress factor due to flooding on to human failure event HARR1. Phase II SAMA 279 to improve internal flooding response has been evaluated.
AHUFD1CLR_0300190	2.23E-03	1.036	CCS PUMPS AND AFW PUMP SPACE COOLER A FAILS TO START ON DEMAND	This event represents the failure of the CCS Pumps and AFW Pumps "A" area cooler to start. Phase II SAMA 289 to install a backup train of room cooling has been evaluated.
TM_1PMP_003001AS	5.72E-03	1.033	Unit 1 TDAFW Pump in Test or Maintenance	This term represents the maintenance unavailability of the turbine driven AFW pump. Phase I SAMAs 72 and 223 to improve the reliability of the AFW turbine driven pump have been implemented.
%1RTIE	3.43E-01	1.032	REACTOR TRIP	This initiator represents a general reactor trip. Phase II SAMA 218, to increase the reliability of power supplies has been evaluated.
TB_SPRAY_FACTOR	1.00E-01	1.032	CONDENSATE FLOOD EVENT IN 662.0-1 Affects the TB Distribution Panels - Non-suppr	This term represents a factor for damage due to spray for flooding events in the Turbine Building. Phase II SAMA 285, to protect equipment in the Turbine Building from internal flooding effects has been evaluated.

Table E.1-3 - Correlation of Unit 1 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
%1CCSA	1.00E+00	1.031	CCS TRAIN 1A INITIATING EVENT IDENTIFIER	This term represents the loss of component cooling water Train 1A initiating event. This event is essentially a flag event in the model which always occurs in cutset containing a component cooling water event leading to the loss of Train 1 A of component cooling water as an initiator. Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.
HXRPL1HEX_0700008AIE	4.23E-03	1.031	CCS HEAT EXCHANGER 1A1 PLUGGING	This term represents the initiating event frequency for component cooling water train A heat exchanger 1A1 plugging failure. This event is a contributor to the loss of component cooling water Train A initiator (%1CCSA) and the total loss of component cooling water initiator (%1CCSTL). Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.
HXRPL1HEX_0700008BIE	4.23E-03	1.031	CCS HEAT EXCHANGER 1A2 PLUGGING	This term represents the initiating event frequency for component cooling water train A heat exchanger 1A2 plugging failure. This event is a contributor to the loss of component cooling water Train A initiator (%1CCSA) and the total loss of component cooling water initiator (%1CCSTL). Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.
TM_1CLR_0300191	2.21E-03	1.031	CCS Pumps and AFW Pump Space Cooler B Maintenance	This term represents the maintenance unavailability of the CCS Pumps and AFW Pump Space Cooler B. Phase II SAMA 289 to install a backup room cooling train was evaluated.
COMBINATION_2322	5.26E+02	1.029	HEP dependency factor for HAOB2,HAMARV	This term is a factor that accounts for the dependency between multiple human failure events (HAOB2, HAMARV) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.

Table E.1-3 - Correlation of Unit 1 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
TM_1CLR_0300190	2.21E-03	1.029	CCS Pumps and AFW Pump Space Cooler A Maintenance	This term represents the maintenance unavailability of the CCS Pumps and AFW Pump Space Cooler A. Phase II SAMA 289 to install a backup room cooling train was evaluated.
%690.0-A01-3_026_S	8.31E-03	1.028	HPFP SPRAY EVENT IN 690.0-A1 – Initiator	This term represents the initiator for a HPFP spray event in partition 3 of room 690.0-A1 in the Auxiliary Building. Phase II SAMA 288 to install spray shields for the component cooling water pumps and CCS pump and AFW pump Space Coolers has been evaluated.
HACD1	4.20E-02	1.028	Perform cooldown with main feedwater, following AFW failure	This event represents the failure of operators to cooldown the RCS with main feedwater given that AFW has failed. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
COMBINATION_210	1.02E+03	1.024	HEP dependency factor for HARR1,AFWOP3,HAMARV	This term is a factor that accounts for the dependency between multiple human failure events (HARR1, AFWOP3, HAMARV) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
TM_1PMP_0700038	5.91E-03	1.024	CCS Pump B in Maintenance	This term represents the unavailability of the CCS B pump due to maintenance. Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.
%662.0-1_026_F	3.84E-02	1.022	HPFP FLOOD EVENT IN 662.0-1 AFFECTS THE TB DISTRIBUTION BOARDS - Initiator	This event represents the initiator for a flood in the Turbine Building which originates from High Pressure Fire Protection system piping. This flood impacts the Turbine Building electrical distribution boards. Phase II SAMA 285, to protect equipment in the Turbine Building from internal flooding effects has been evaluated.

Table E.1-3 - Correlation of Unit 1 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
RCPSEAL182	2.08E-01	1.022	RCP SEAL 182 GPM	This term represents a 182 gpm RCP seal leak that occurs as the result of loss of CCS Train A and seal injection. Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, and 215 have also been evaluated. Phase II SAMAs 55, 56, 226 and 240 to increase reliability of seal injection have also been evaluated.
TM_U1PMP0740020	5.33E-03	1.022	RHR PUMP 1A-A IS UNAVAILABLE DUE TO TEST OR MAINTENANCE	This term represents the maintenance unavailability of motor driven RHR Pump 1A-A. Phase II SAMA 278 improving the reliability of the RHR pumps has been evaluated.
HXRPL1_IEF_CCS_HX_ 1A1/2_&_OB1/2	6.29E-05	1.02	IE FREQENCY FOR CCF OF HEAT EXCHANGER 1A1/2 AND 0B1/2 PLUGGING	This term represents the initiating event frequency for the common cause failure of both the train 1A and train 0B component cooling heat exchangers plugging. This event leads to the total loss of component cooling system initiator (%1CCSTL). Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.
%0LOSP-WI	4.06E-03	1.019	Loss of Offsite Power (Weather Induced)	This term represents the loss of offsite power sources due to weather related events affecting all sources of offsite power. Phase 1 SAMAs addressing power reliability and coping capability for SBO that have been implemented or determined to have excessive implementation cost include SAMAs 1, 2, 3, 4, 9, 10, 13, 22, 23, 24, 67, 173, 176, 216, 229 and 244. Phase II SAMAs 70, 167, 215, 226, and 240 to improve coping capability during an SBO have been evaluated.
U1_02RHRPSRFD_1_2	1.49E-04	1.019	CCF of two components: PSRFD1PMP_0740010 & PSRFD1PMP_0740020	This term represents the common cause failure of the RHR pumps failing to start. Phase I SAMA 44 for using air cooled motors for ECCS pumps has been implemented. Phase II SAMA 278 improving the reliability of the RHR pumps has been evaluated.

Table E.1-3 - Correlation of Unit 1 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
%1TLMFW	9.55E-02	1.018	TOTAL LOSS OF MAIN FEEDWATER	This initiating event represents the total loss of main feedwater. Phase I SAMAs 65, 77 and 221 have been implemented or determined to have excessive implementation cost. Phase II SAMA 68 has been evaluated.
%1TTIE	1.94E-01	1.018	TURBINE TRIP	This term represents a plant initiator due to a turbine trip. Phase I SAMA 225 to upgrade main turbine controls has been implemented. Phase II SAMA 218 to improve the reliability of power supplies has been evaluated.
COMBINATION_1942	1.92E+01	1.018	HEP dependency factor for HARR1,HAFR1	This term is a factor that accounts for the dependency between multiple human failure events (HARR1, HAFR1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
RCPSEAL021	7.90E-01	1.018	RCP SEAL 21 GPM	This term represents a 21 gpm RCP seal leak that occurs as the result of loss of CCS Train A and seal injection. Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45 and 215 have also been evaluated. Phase II SAMAs 55, 56, 226 and 240 to increase reliability of seal injection have also been evaluated.
U0_CAS02CMPSR_1_2	2.20E-03	1.018	CCF of two components: ACPFR0CMP_0320060 & ACPFR0CMP_0320086	This term represents the common case failure of ACAS Compressors A and B to run. Phase II SAMAs 70, 87, 188 to increase reliability of air systems and coping capability on their loss have been evaluated.
%690.0-A01-3_067_F_0B	5.34E-05	1.017	ERCW FLOOD EVENT IN 690.0-A01-3 FROM B DISCHARGE HEADER - Initiator	This term represents the initiator for an ERCW flood event in partition 3 of room 690.0-A1 in the Auxiliary Building. This initiator results in failure of seal cooling due to loss of component cooling. Phase II SAMA 215 to provide an independent seal cooling system has been evaluated.
%690.0-A01-3_067_M_0B	5.34E-05	1.017	ERCW MAJOR FLOOD EVENT IN 690.0-A01-3 FROM B DISCHARGE HEADER - Initiator	This term represents the initiator for an ERCW major flood event in partition 3 of room 690.0-A1 in the Auxiliary Building. This initiator results in failure of seal cooling due to loss of component cooling. Phase II SAMA 215 to provide an independent seal cooling system has been evaluated.

Table E.1-3 - Correlation of Unit 1 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
PSRFD1PMP_0740020	3.66E-03	1.017	Residual Heat Removal Pump Fails to Start (1-PMP-074-0020)	This event represents the random failure of RHR Pump 1B-B to start. Phase I SAMA 44 for using air cooled motors for ECCS pumps has been implemented. Phase II SAMA 278 improving the reliability of the RHR pumps has been evaluated.
%662.0-1_026_F-1	3.84E-02	1.016	HPFP FLOOD EVENT IN 662.0-1 DOES NOT AFFECT THE TB DISTRIBUTION BOARDS - Initiator	This event represents the initiator for a flood in the Turbine Building which originates from High Pressure Fire Protection system piping. This flood does not impact the Turbine Building electrical distribution boards. Phase II SAMA 285, to protect equipment in the Turbine Building from internal flooding effects has been evaluated.
COMBINATION_919	2.38E+01	1.015	HEP dependency factor for HARR1,HACD1	This term is a factor that accounts for the dependency between multiple human failure events (HARR1, HACD1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
U1_04AFWPORFO_ALL	1.06E-04	1.015	CCF of all components in group 'U1_04AFWPORFO'	This term represents the common cause failure of all four SG atmospheric relief valves to open on demand. Phase II SAMA 276 to reduce the likelihood of common cause failure of SG atmospheric relief valves was evaluated.
U1_CRI	1.20E-06	1.015	UNIT 1 CONTROL RODS FAIL TO INSERT	This term represents the hardware failure of control rods to insert when required. Phase II SAMA 277 to improve the reliability of the control rods has been evaluated.
%1PLMFW	1.53E-01	1.014	Partial Loss of Main Feedwater	This initiating event represents the partial loss of main feedwater. Phase I SAMAs 65, 77 and 221 have been implemented or determined to have excessive implementation cost. Phase II SAMA 68 has been evaluated.
COMBINATION_1408	5.31E+02	1.014	HEP dependency factor for HAFR2,HAOB2,HAFR1	This term is a factor that accounts for the dependency between multiple human failure events (HAFR2, HAOB2, HAFR1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.

Table E.1-3 - Correlation of Unit 1 Level 1 Risk Significant Terms to SAMAs (Based on CDF)				
Event Name	**Probability**	**RRW**	**Event Description**	**Disposition**
%714.0-A01-1_067_F_0B	4.10E-05	1.013	ERCW FLOOD EVENT IN 714.0-A1-1 FROM DISCHARGE B - Initiator	This term represents the initiator for an ERCW flood event in partition 1 of room 714.0-A1 in the Auxiliary Building. This initiator results in failure of seal cooling due to loss of component cooling. Phase II SAMA 215 to provide an independent seal cooling system has been evaluated.
%1LDAAC	1.00E+00	1.012	Loss of 120V AC Vital Instrument Board I	This term represents the failure of the 120V AC Vital Instrument Board I. Phase I SAMAs 7 and 16, which improve the reliability of 120V AC have been implemented. Phase II SAMA 8 for improving training on loss of 120V AC has been evaluated.
%1LDBAC	1.00E+00	1.012	Loss of 120V AC Vital Instrument Board II	This term represents the failure of the 120V AC Vital Instrument Board II. Phase I SAMAs 7 and 16, which improve the reliability of 120V AC have been implemented. Phase II SAMA 8 for improving training on loss of 120V AC has been evaluated
BUSFR1BDE250NC_D_IE	9.94E-04	1.012	Electrical Bus Failure of 1-BDE-250-NC-D	This term represents the initiating event failure of the electrical bus associated with Vital Instrument Power Board 1-I (%1LDAAC). This term represents the failure of the 120V AC Vital Instrument Board I. Phase I SAMAs 7 and 16, which improve the reliability of 120V AC have been implemented. Phase II SAMA 8 for improving training on loss of 120V AC has been evaluated.
BUSFR1BDE250NE_E_IE	9.94E-04	1.012	Bus Fails to Operate	This term represents the initiating event failure of the electrical bus associated with Vital Instrument Power Board 1-II (%1LDBAC). This term represents the failure of the 120V AC Vital Instrument Board I. Phase I SAMAs 7 and 16, which improve the reliability of 120V AC have been implemented. Phase II SAMA 8 for improving training on loss of 120V AC has been evaluated.
COMBINATION_213	2.09E+04	1.012	HEP dependency factor for HASE2,HARR1,AFWOP3,HAMARV	This term is a factor that accounts for the dependency between multiple human failure events (HASE2, HARR1, AFWOP3, HAMARV) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.

Table E.1-3 - Correlation of Unit 1 Level 1 Risk Significant Terms to SAMAs (Based on CDF)				
Event Name	**Probability**	**RRW**	**Event Description**	**Disposition**
PTSFR1PMP_0030142	1.76E-03	1.012	Turbine Driven Aux-Feedwater Pump Fails to Run	This event represents the random failure of the turbine driven AFW pump to run. Phase 1 SAMAs 72, 73, 74 and 223 to improve the reliability of the AFW turbine driven pump have been implemented.
TM_1PMP0030118A	5.72E-03	1.012	MDAFW Pump 1A-A in Test or Maintenance	This term represents the maintenance unavailability of motor driven AFW Pump 1A-A. Phase I SAMA 223 to improve the reliability of the AFW pumps and valves has been implemented.
%1SSBO-1	2.93E-03	1.011	SECONDARY SIDE BREAK OUTSIDE CONTAINMENT-SG 1	This event represents secondary side break outside containment initiator. Important actions associated with this initiator are failure to terminate safety injection (SSIOP) and failure to align high pressure recirculation (HARR1). Phase I SAMAs 31, 36, and 247 to improve reliability of recirculation have been implemented. Phase II SAMAs 32, 103 and 283 for automatic recirculation and improved operator training have been evaluated.
%1SSBO-2	2.93E-03	1.011	SECONDARY SIDE BREAK OUTSIDE CONTAINMENT-SG 2	Same as %1SSBO-1.
%1SSBO-3	2.93E-03	1.011	SECONDARY SIDE BREAK OUTSIDE CONTAINMENT-SG 3	Same as %1SSBO-1.
%1SSBO-4	2.93E-03	1.011	SECONDARY SIDE BREAK OUTSIDE CONTAINMENT-SG 4	Same as %1SSBO-1.
AFWOP3_FL	5.00E+00	1.01	FLOODING MULTIPLIER FOR AFWOP3	This term is used to add an additional stress factor due to flooding on to human failure event AFWOP3. Phase II SAMA 279 to improve internal flooding response has been evaluated.
AHUFD1CLR_0300176	2.23E-03	1.01	Air Handling Unit (Standby) Fails to Start (1-CLR-030-0176)	This event represents the failure of RHR Pump 1B-B Room air handling unit failure to start. Phase II SAMA 160 to improve coping capability for the loss of room cooling has been evaluated.
U1_02RHRAHUFD_1_2	8.12E-05	1.01	CCF of two components: AHUFD1CLR_0300175 & AHUFD1CLR_0300176	This term represents the common cause failure of the RHR Pump 1A-A and 1B-B pump room coolers to start. Phase II SAMA 160 to improve coping capability for the loss of room cooling has been evaluated.

Table E.1-3 - Correlation of Unit 1 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
CMPSD0CMP_0320060	1.02E-02	1.009	COMPRESSOR A FAILS TO START	This term represents the failure of Auxiliary Control Air System (ACAS) Compressor A failing to start. Phase II SAMAs 70, 87, 188 to increase reliability of air systems and coping capability on their loss have been evaluated.
CMPSD0CMP_0320086	1.02E-02	1.009	COMPRESSOR B FAILS TO START	This term represents the failure of Auxiliary Control Air System (ACAS) Compressor B failing to start. Phase II SAMAs 70, 87, 188 to increase reliability of air systems and coping capability on their loss have been evaluated.
TM_1PMP0030128B	5.72E-03	1.009	MDAFW Pump 1B in Test or Maintenance	This term represents the maintenance unavailability of motor driven AFW Pump 1A-A. Phase I SAMA 223 to improve the reliability of the AFW pumps and valves has been implemented.
U0_CCS02AHUFR_1_2	8.56E-06	1.009	CCF of two components: AHUFR1CLR_0300190 & AHUFR1CLR_0300191	This term represents the common cause failure of CCS and AFW Pump Space Coolers A and B to run. Phase II SAMA 289 to install a backup room cooling train was evaluated.
U1_RPS02RTBFO_1_2	1.38E-06	1.009	CCF of two components: RTBFO1BKRC099KE320A & RTBFO1BKRC099KF320B	This term represents the common cause failure of the reactor trip breakers 1-BKRC-099-KE/320-A and 1-BKRC-099-KF/320-B to trip open on demand. Phase II SAMAs 136 and 137 have been evaluated.
AHUFD_SOK_2	1.22E+00	1.008	AHUFD State of Knowledge Factor for a group of 2	This term is a factor used to address the state of knowledge correlation for two air handling units. It is used to adjust the frequency of cutsets which contain two air handling unit events. Phase II SAMA 160 to improve coping capability for the loss of room cooling has been evaluated.
PCOFD1PMP_0700038	2.38E-03	1.008	PUMP B FAILS TO START ON DEMAND	This term represents the failure of component cooling water Pump 1B to start on a demand. Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.

Table E.1-3 - Correlation of Unit 1 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
SRVWR1SRV_06800563	1.00E-01	1.008	SAFETY VALVE FAILS TO RESEAT AFTER WATER RELIEF SQN-1-VLV-068-0563	This event represents the failure of one of three pressurizer safety relief valves to reclose following a water (versus steam) pressure relief which then leads to a small LOCA type scenario. Phase II SAMA 284 to reduce probability that the pressurizer safety relief valves fail to close was evaluated.
SRVWR1SRV_06800564	1.00E-01	1.008	SAFETY VALVE FAILS TO RESEAT AFTER WATER RELIEF SQN-1-VLV-068-0564	This event represents the failure of one of three pressurizer safety relief valves to reclose following a water (versus steam) pressure relief which then leads to a small LOCA type scenario. Phase II SAMA 284 to reduce probability that the pressurizer safety relief valves fail to close was evaluated.
SRVWR1SRV_06800565	1.00E-01	1.008	SAFETY VALVE FAILS TO RESEAT AFTER WATER RELIEF SQN-1-VLV-068-0565	This event represents the failure of one of three pressurizer safety relief valves to reclose following a water (versus steam) pressure relief which then leads to a small LOCA type scenario. Phase II SAMA 284 to reduce probability that the pressurizer safety relief valves fail to close was evaluated.
TKPRP1TNK_0700063IE	2.41E-05	1.008	SURGE TANK A RUPTURE	This term represents the initiating event frequency for component cooling water train A surge tank failure due to rupture. This event is a contributor to the loss of component cooling water Train A initiator (%1CCSA) and the total loss of component cooling water initiator (%1CCSTL). Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.
%662.0-1_026_M	1.27E-02	1.007	HPFP MAJOR FLOOD EVENT IN 662.0-1 AFFECTS THE TB DISTRIBUTION BOARDS - Initiator	This event represents initiator for a major flood in the Turbine Building which originates from High Pressure Fire Protection system piping. This major flood impacts the Turbine Building electrical distribution boards. Phase II SAMA 285, to protect equipment in the Turbine Building from internal flooding effects has been evaluated.

Table E.1-3 - Correlation of Unit 1 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
%690.0-A01-1_067_F_2A	8.77E-04	1.007	ERCW FLOOD EVENT IN 690.0-A1-1 FROM 2A-A HEADER - Initiator	This term represents the initiator for an ERCW flood event in partition 1 of room 690.0-A1 in the Auxiliary Building. This initiator results in isolation of ERCW header and loss of component cooling water and RCP seal cooling. Phase II SAMA 215 to provide an independent seal cooling system has been evaluated.
%690.0-A01-2_024_S	9.99E-04	1.007	RCW SPRAY EVENT IN 690.0-A1-2 - Initiator	This term represents the initiator for a RCW spray event in partition 2 of room 690.0-A1 in the Auxiliary Building. Phase II SAMAs 288 and 275 to install spray shields for the component cooling water pumps and CCS pump and AFW pump Space Coolers; and install spray shields on the AFW pumps and AFW/BAT Space Coolers have been evaluated.
MORXC0FCV_0670478IE	3.90E-04	1.007	FCV 67-478 TRANSFERS CLOSED	This term represents the failure of ERCW valve FCV 67-478, which supplies cooling water to the Train A component cooling water heat exchangers. This is a contributor to the loss of component cooling water Train A initiator (%1CCSA) and the total loss of component cooling water initiator (%1CCSTL). Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.
MORXC1FCV_0670146IE	3.90E-04	1.007	FCV 67-146 TRANSFERS CLOSED	This term represents the failure of ERCW valve FCV 67-146, which is in the cooling water return line from the Train A component cooling water heat exchangers. This is a contributor to the loss of component cooling water Train A initiator (%1CCSA) and the total loss of component cooling water initiator (%1CCSTL). Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.

Table E.1-3 - Correlation of Unit 1 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
MORXC1FCV_0670223IE	3.90E-04	1.007	FCV 67-223 TRANSFERS CLOSED	This term represents the failure of ERCW valve (U1) FCV 67-223, which supplies cooling water to the Train A component cooling water heat exchangers. This is a contributor to the loss of component cooling water Train A initiator (%1CCSA) and the total loss of component cooling water initiator (%1CCSTL). Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.
MORXC2FCV_0670223IE	3.90E-04	1.007	FCV 67-223 TRANSFERS CLOSED	This term represents the failure of ERCW valve (U2) FCV 67-223, which supplies cooling water to the Train A component cooling water heat exchangers. This is a contributor to the loss of component cooling water Train A initiator (%1CCSA) and the total loss of component cooling water initiator (%1CCSTL). Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.
PCOFR1PMP_0700046IE	3.90E-02	1.007	PUMP A FAILS TO OPERATE	This term represents the initiating event frequency of component cooling water Pump A failing to run. It is a contributor to the loss of component cooling water Train A initiator (%1CCSA) and the total loss of component cooling water initiator (%1CCSTL). Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.
U0_ERW04STRPL_ALL	6.49E-07	1.007	CCF of all components in group 'U0_ERW04STRPL'	This term represents the common cause plugging of the ERCW river water strainers. Phase I SAMA 202 and 264 for enhancing screen wash and for improved procedures for coping with loss of ERCW have been implemented. Phase II SAMA 46 for adding a service water pump has been evaluated.
%690.0-A01-1_026_S	8.31E-03	1.006	HPFP SPRAY EVENT IN 690.0-A1 - Initiator	This term represents the initiator for a HPFP spray event in partition 1 of room 690.0-A1 in the Auxiliary Building. Phase II SAMA 275 to install spray shields on the AFW pumps and AFW/BAT Space Cooler has been evaluated.

Table E.1-3 - Correlation of Unit 1 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
%690.0-A01-1_067_S	8.44E-03	1.006	ERCW SPRAY EVENT IN 690.0-A1 - Initiator	This term represents the initiator for an ERCW spray event in partition 1 of room 690.0-A1 in the Auxiliary Building. This initiator results in the loss of AFW pumps. Phase II SAMA 068 to install an additional feedwater pump has been evaluated.
COMBINATION_2365	2.63E+01	1.006	HEP dependency factor for HARR1,HAMARV	This term is a factor that accounts for the dependency between multiple human failure events (HARR1, HAMARV) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
PMAFD1PMP_00300118	1.86E-03	1.006	MDAFW PUMP FAILS TO START SQN-1-3-118-A	This term represents the random failure of motor driven AFW Pump 1A-A failing to start. Phase I SAMAs 196 and 223 for adding a motor driven AFW pump and improving reliability of AFW pumps and valves have been implemented.
PSRFD1PMP_0740010	3.66E-03	1.006	Residual Heat Removal Pump Fails to Start (1-PMP-074-0010)	This term represents the random failure of RHR Pump 1A-A to start. Phase I SAMA 44 for using air cooled motors for ECCS pumps has been implemented. Phase II SAMA 278 improving the reliability of the RHR pumps has been evaluated.
U1_0BLOCK	7.50E-01	1.006	Probability that 0 PORVs are blocked	This term represents the fraction of time during plant operation that no PORVs are blocked. This event is related to logic associated with the number of PORVs and safety valves that are required during ATWS events. Since this is the preferable state, no evaluation is necessary.
%1LOCV	2.97E-02	1.005	Loss of Condenser Vacuum	This term represents an initiating event as a result of loss of condenser vacuum. This event is bounded by the total loss of main feedwater initiator (%1TLMFW) since condenser vacuum supports main feedwater. Phase I SAMAs 65, 77 and 221 have been implemented or determined to have excessive implementation cost. Phase II SAMA 68 has been evaluated.
%662.0-1_026_M-1	1.27E-02	1.005	HPFP MAJOR FLOOD EVENT IN 662.0-1 DOES NOT AFFECT THE TB DISTRIBUTION BOARDS - I	This event represents the initiator for a major flood in the Turbine Building which originates from High Pressure Fire Protection system piping. This flood does not impact the Turbine Building electrical distribution boards. Phase II SAMA 285, to protect equipment in the Turbine Building from internal flooding effects has been evaluated.

Table E.1-3 - Correlation of Unit 1 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
%669.0-A01_067_S	6.08E-03	1.005	ERCW SPRAY EVENT IN 669.0-A1 - Initiator	This term represents the initiator for an ERCW spray event in room 669.0-A1 of the Auxiliary Building. This initiator results in the loss of an AFW pump. Phase II SAMA 068 to install an additional feedwater pump has been evaluated.
%714.0-A01-2_067_F_1A	1.23E-03	1.005	ERCW FLOOD EVENT IN 714.0-A1-2 FROM 1A-A HEADER - Initiator	This term represents the initiator for an ERCW flood event in partition 2 of room 714.0-A1 in the Auxiliary Building This initiator results in failure of seal cooling due to loss of component cooling. Phase II SAMA 215 to provide an independent seal cooling system has been evaluated.
%734.0-A13-2_067_F_0B	1.60E-05	1.005	ERCW FLOOD EVENT IN 734.0-A13-2 FROM DISCHARGE HEADER B - Initiator	This term represents the initiator for an ERCW flood event in partition 1 of room 734.0-A13 in the Auxiliary Building. This initiator results in failure of seal cooling due to loss of component cooling. Phase II SAMA 215 to provide an independent seal cooling system has been evaluated.
COMBINATION_2674	9.89E-01	1.005	HEP dependency factor for HARR1,SSIOP	This term is a factor that accounts for the dependency between multiple human failure events (HARR1, SSIOP) that occur in the same cutset. . Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
SSIOP	5.90E-04	1.005	Terminate Safety Injection to prevent PORV water challenge	This term represents the failure of operators to terminate safety injection. Phase II SAMA 283 to increase the awareness of important human actions was evaluated.

Table E.1-4 - Correlation of Unit 2 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
HARR1	2.40E-02	1.466	Align high pressure recirculation, given auto swapover works	This event represents the failure of operators to align high pressure recirculation given that auto swapover to containment sump has failed. Phase I SAMAs 31 and 36 dealing with alignment of recirculation have been implemented. Phase II SAMAs 32, 103 and 283, evaluated automatic recirculation alignment and increase training and improve awareness of important operator actions have been evaluated.
HARR1_FL	5.00E+00	1.298	FLOODING MULTIPLIER FOR HARR1	This term is used to add a stress factor because of flooding on to human failure event HARR1. Phase II SAMA 279 to improve internal flooding response has been evaluated.
HACD1	4.20E-02	1.231	Perform cooldown with main feedwater, following AFW failure	This event represents the failure of operators to cooldown the RCS with main feedwater given tha AFW has failed. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
COMBINATION_919	2.38E+01	1.213	HEP dependency factor for HARR1,HACD1	This term is a factor that accounts for the dependency between multiple human failure events (HARR1, HACD1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
HASE2	4.60E-03	1.21	Trip RCPs on loss of Component Cooling Water	This term represents operator failure to trip the reactor cooling pumps on loss of component cooling water in order to prevent failure of the RCP seals. Phase I SAMAs 59, 61, 154, 155, 156, 157, 260 and 264, to reduce the likelihood of the need to trip RCP pumps have been implemented. Phase II SAMAs 55, 56, 103, 215 and 283 to increase the reliability of seal injection or cooling and increase training and improve awareness of important operator actions have been evaluated.
PTSFD2PMP_0030142	9.38E-03	1.165	TURBINE DRIVEN PUMP FAILS TO START ON DEMAND	This event represents the random failure of the turbine driven AFW pump to start. Phase I SAMAs 72, 73, 74 and 223 to improve the reliability of the AFW turbine driven pump have been implemented.
%690.0-A01-4_026_S	1.31E-03	1.108	HPFP SPRAY EVENT IN 690.0-A1 - Initiator	This event represents the initiator for a HPFP spray event in partition 4 of room 690.0-A1. Phase II SAMA 275 to install spray shields for the AFW and BAT Pump Space Coolers has been evaluated.

Table E.1-4 - Correlation of Unit 2 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
%0_ELB_FLOOD	3.57E-06	1.104	ELECTRIC BOARD ROOM FLOODS - Initiator	This event is a combination of individual flooding initiators, all of which either originate in or propagate to both electric board rooms 734.0-A2 and 734.0-A24. As modeled, this initiator results in the loss of all AC power. Phase II SAMA 286 to limit internal flooding propagation between electrical divisions on Auxiliary Building elevation 734.0 has been evaluated.
%2CCSTL	1.00E+00	1.099	UNIT 2 CCSTL INITIATING EVENT IDENTIFIER	This term represents the total loss of component cooling water system initiator. This term is essentially a flag event in the model which always occurs in cutsets containing component cooling water events leading to the total loss of component cooling water and plant trip. Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.
%662.0-1_026_S	2.84E-01	1.089	HPFP SPRAY EVENT IN 662.0-1 - Initiator	This event represents the initiator for a HPFP spray event in the Turbine Building which originates from High Pressure Fire Protection system piping. Phase II SAMA 285, to protect equipment in the Turbine Building from internal flooding effects has been evaluated.
TM_2PMP_0030142	5.72E-03	1.089	TURBINE DRIVEN PUMP IN MAINTENANCE	This term represents the maintenance unavailability of the turbine driven AFW pump. Phase 1 SAMAs 72 and 223 to improve the reliability of the AFW turbine driven pump have been implemented.
%2SLOCAL	2.84E-03	1.077	STUCK OPEN SAFETY/RELIEF VALVE	This event represents a stuck open safety/relief valve initiator, which has a plant response similar to that of a small break LOCA. Important actions associated with this initiator are failure to align high pressure recirculation (HARR1) and failure to cooldown and depressurize (AFWOP3). Phase I SAMAs 36, 41 and 42 improve capability for cooldown and depressurization have been implemented. Phase II SAMAs 32, 103 and 283 for automatic recirculation and improved operator training have been evaluated.

Table E.1-4 - Correlation of Unit 2 Level 1 Risk Significant Terms to SAMAs (Based on CDF)				
Event Name	**Probability**	**RRW**	**Event Description**	**Disposition**
ACPFR0CMP_0320060	7.68E-02	1.072	COMPRESSOR A FAILS TO RUN	This term represents the failure of Auxiliary Control Air System compressor A to continue to run. Phase II SAMAs 70, 87, 188 to increase reliability of air systems and coping capability on their loss have been evaluated.
ACPFR0CMP_0320086	7.68E-02	1.072	COMPRESSOR B FAILS TO RUN	This term represents the failure of Auxiliary Control Air System compressor B to continue to run. Phase II SAMAs 70, 87, 188 to increase reliability of air systems and coping capability on their loss have been evaluated.
HAFR1	2.60E-03	1.072	Restore MDAFW LCV control following initiator and loss of air	This event represents the failure of operators to connect nitrogen bottles for AFW level control valves. Phase I SAMA 73, for local manual operation of auxiliary feedwater system, has been implemented. Phase II SAMAs 70, 87, 103, 188, and 283 to improve the reliability of air systems and increase training and awareness of important operator actions have been evaluated.
HAMARV	1.90E-03	1.067	Handwheel Operation of the Steam Generator Atmospheric Relief Valves S/G 1&4	This term represents the failure of operators to manually open SG atmospheric relief valves in the event of the failure of air and power support systems. Phase I SAMA 40 for remote manual capability of SG PORVs has been implemented. Phase II SAMAs 87, 88, 188 and 283 to increase the reliability of air systems and PORVs, and to increase training and improve awareness of important operator actions have been evaluated.
HAOB2	5.60E-03	1.062	Establish RCS Bleed and Feed cooling given no CCPS running	This term represents the failure of operators to establish feed and bleed operation given that chemical and volume control pumps are available. Phase II SAMAs 103 and 283 to increase training and improve awareness of important operator actions have been evaluated.
ACPFR_SOK_2	1.37E+00	1.06	ACPFR Stake of Knowledge Factor for a group of 2	This term is a factor used to address the state of knowledge correlation for two air compressors. It is used to adjust the frequency of cutsets which contain two air compressor events. Phase II SAMAs 70, 87, 188 to increase reliability of air systems and coping capability on their loss have been evaluated.

Table E.1-4 - Correlation of Unit 2 Level 1 Risk Significant Terms to SAMAs (Based on CDF)				
Event Name	**Probability**	**RRW**	**Event Description**	**Disposition**
SHECLR-2	4.40E-03	1.058	Mispositioning ERCW valves, blocking flow to the CCS/AFW and the BAT/AFW space coolers	This term represents the failure of operators to properly position ERCW valves following a flush procedure for the CCS, BAT and AFW pump Train B space coolers. This is a pre-initiator event. Phase II SAMA 283 to increase awareness of important human actions has been evaluated.
HAFR2	2.20E-03	1.054	Restore TDAFWP speed control following initiator and loss of air	This event represents the failure of operators to restore speed control of the turbine driven AFW pump following loss of air. Phase I SAMA 73 to proceduralize local manual operation of auxiliary feedwater system when control power is lost has been implemented. Phase II SAMAs 103 and 283 to increase training and improve awareness of important operator actions have been evaluated.
HAFR2_FL	5.00E+00	1.054	FLOODING MULTIPLIER HARFR2	This term is used to add a stress factor because of flooding on to human failure event HAFR2. Phase II SAMA 279 to improve internal flooding response has been evaluated.
SHECLR-1	4.40E-03	1.054	Mispositioning ERCW valves, blocking flow to the CCS/AFW and the BAT/AFW space coolers	This term represents the failure of operators to properly position ERCW valves following a flush procedure for the CCS, BAT and AFW pump Train A space coolers. This is a pre-initiator event. Phase II SAMA 283 to increase awareness of important human actions has been evaluated.
U0_CCS02AHUFD_1_2	8.12E-05	1.054	CCF of two components: AHUFD1CLR_0300190 & AHUFD1CLR_0300191	This term represents the common cause failure of CCS and AFW Pump Space Coolers A and B to start on demand. Phase II SAMA 289 to install a backup room cooling train was evaluated.
%690.0-A01-4_067_S	5.91E-04	1.046	ERCW SPRAY EVENT IN 690.0-A1 - Initiator	This event represents the initiator for an ERCW spray event in partition 4 of room 690.0-A1. Phase II SAMA 275 to install spray shields for the AFW and BAT Pump Space Coolers has been evaluated.
CBKFO2BKR_0680008	1.34E-03	1.046	SQN-2-BCTA-068-0008 BREAKERS FAILS TO OPEN ON DEMAND FOR RCP 1	The term represents the failure of the Reactor Coolant Pump 1 circuit breakers to open when demanded. Phase I SAMAs 59, 61, 154, 155, 156, 157, 260 and 264, to reduce the likelihood of the need to trip RCP pumps have been implemented. Phase II SAMAs 55, 56 and 215 have also been evaluated.

Table E.1-4 - Correlation of Unit 2 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
CBKFO2BKR_0680031	1.34E-03	1.046	SQN-2-BCTA-068-0031 BREAKERS FAILS TO OPEN ON DEMAND FOR RCP 2	The term represents the failure of the Reactor Coolant Pump 2 circuit breakers to open when demanded. Phase I SAMAs 59, 61, 154, 155, 156, 157, 260 and 264, to reduce the likelihood of the need to trip RCP pumps have been implemented. Phase II SAMAs 55, 56 and 215 have also been evaluated.
CBKFO2BKR_0680050	1.34E-03	1.046	SQN-2-BCTA-068-0050 BREAKERS FAILS TO OPEN ON DEMAND FOR RCP 3	The term represents the failure of the Reactor Coolant Pump 3 circuit breakers to open when demanded. Phase I SAMAs 59, 61, 154, 155, 156, 157, 260 and 264, to reduce the likelihood of the need to trip RCP pumps have been implemented. Phase II SAMAs 55, 56 and 215 have also been evaluated.
CBKFO2BKR_0680073	1.34E-03	1.046	SQN-2-BCTA-068-0073 BREAKERS FAILS TO OPEN ON DEMAND FOR RCP 4	The term represents the failure of the Reactor Coolant Pump 4 circuit breakers to open when demanded. Phase I SAMAs 59, 61, 154, 155, 156, 157, 260 and 264, to reduce the likelihood of the need to trip RCP pumps have been implemented. Phase II SAMAs 55, 56 and 215 have also been evaluated.
%690.0-A01-2_026_S	8.31E-03	1.042	HPFP SPRAY EVENT IN 690.0-A1-2 - Initiator	This event represents the initiator for a HPFP flood event in partition 2 of room 690.0-A1 in the Auxiliary Building. Phase II SAMA 288 to install spray shield for the CCS pumps and CCS/AFW Space Coolers has been evaluated.
COMBINATION_1593	4.22E+02	1.041	HEP dependency factor for HAFR2,HARR1,HAFR1	This term is a factor that accounts for the dependency between multiple human failure events (HAFR2, HARR1, HAFR1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
HACD2	8.80E-03	1.039	Perform cooldown with auxiliary feedwater and steam dumps	This event represents the failure of operators perform cooldown with auxiliary feedwater and steam dumps. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
AFWOP3	4.10E-03	1.034	Depressurize/cooldown to LP injection after a small or medium LOCA with failure of HP recirculation	This term represents the failure of operators to depressurize and cooldown vessel so that low pressure injection can be used following a small or medium LOCA with failure of high pressure recirculation. Phase I SAMAs 36, 41 and 42 improve capability for cooldown and depressurization have been implemented.

Table E.1-4 - Correlation of Unit 2 Level 1 Risk Significant Terms to SAMAs (Based on CDF)				
Event Name	**Probability**	**RRW**	**Event Description**	**Disposition**
TB_SPRAY_FACTOR	1.00E-01	1.028	CONDENSATE FLOOD EVENT IN 662.0-1 Affects the TB Distribution Panels - Non-suppr	This term represents a factor for damage due to spray for flooding events in the Turbine Building. Phase II SAMA 285, to protect equipment in the Turbine Building from internal flooding effects has been evaluated.
%2RTIE	3.43E-01	1.027	REACTOR TRIP	This initiator represents a general reactor trip. Phase II SAMA 218, to increase the reliability of power supplies has been evaluated.
HXRPL2HEX_0700015AIE	4.23E-03	1.027	CCS HEAT EXCHANGER 2A1 PLUGGING	This term represents the initiating event frequency for component cooling water train A heat exchanger 2A1 plugging failure. This event is a contributor to the loss of component cooling water Train A initiator (%2CCSA) and the total loss of component cooling water initiator (%2CCSTL). Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.
COMBINATION_1219	1.70E+01	1.026	HEP dependency factor for HARR1,HACD2	This term is a factor that accounts for the dependency between multiple human failure events (HARR1, HACD2) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
HXRPL2HEX_0700015BIE	4.23E-03	1.026	CCS HEAT EXCHANGER 2A2 PLUGGING	This term represents the initiating event frequency for component cooling water train A heat exchanger 2A2 plugging failure. This event is a contributor to the loss of component cooling water Train A initiator (%2CCSA) and the total loss of component cooling water initiator (%2CCSTL). Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.
PTSFR2PMP_0030142	1.76E-03	1.026	Turbine Driven Aux-Feedwater Pump Fails to Run	This event represents the random failure of the turbine driven AFW pump to run. Phase 1 SAMAs 72, 73, 74 and 223 to improve the reliability of the AFW turbine driven pump have been implemented.

Table E.1-4 - Correlation of Unit 2 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
RCPSEAL182	2.08E-01	1.025	RCP SEAL 182 GPM	This term represents a 182 gpm RCP seal leak that occurs as the result of loss of CCS Train A and seal injection. Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45 and 215 have also been evaluated. Phase II SAMAs 55, 56, 226 and 240 to increase reliability of seal injection have also been evaluated.
AHUFD1CLR_0300191	2.23E-03	1.024	CCS PUMPS AND AFW PUMPS SPACE COOLER B FAILS TO START ON DEMAND	This event represents the failure of the CCS Pumps and AFW Pumps "B" area cooler to start. Phase II SAMA 289 to install a backup train of room cooling has been evaluated.
COMBINATION_2322	5.26E+02	1.024	HEP dependency factor for HAOB2,HAMARV	This term is a factor that accounts for the dependency between multiple human failure events (HAOB2, HAMARV) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
TM_1CLR_0300191	2.21E-03	1.023	CCS Pumps and AFW Pump Space Cooler B Maintenance	This term represents the maintenance unavailability of the CCS Pumps and AFW Pump Space Cooler B. Phase II SAMA 289 to install a backup room cooling train was evaluated.
TM_2PMP_0700033	5.91E-03	1.023	CCS Pump B in Maintenance	This term represents the unavailability of the CCS B pump due to maintenance. Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.
%2CCSA	1.00E+00	1.022	CCS TRAIN 2A INITIATING EVENT IDENTIFIER	This term represents the loss of component cooling water Train 2A initiating event. This event is essentially a flag event in the model which always occurs in cutsets containing a component cooling water event leading to the loss of Train 2A of component cooling water as an initiator. Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.

Table E.1-4 - Correlation of Unit 2 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
AHUFD1CLR_0300190	2.23E-03	1.022	CCS PUMPS AND AFW PUMP SPACE COOLER A FAILS TO START ON DEMAND	This event represents the failure of the CCS Pumps and AFW Pumps "A" area cooler to start. Phase II SAMA 289 to install a backup train of room cooling has been evaluated.
%690.0-A01-3_026_S	8.31E-03	1.021	HPFP SPRAY EVENT IN 690.0-A1 - Initiator	This event represents the initiator for a HPFP spray event in partition 3 of room 690.0-A1. Phase II SAMA288 to install spray shields for CCS pumps and CCS/AFW space coolers has been evaluated.
COMBINATION_210	1.02E+03	1.021	HEP dependency factor for HARR1,AFWOP3,HAMARV	This term is a factor that accounts for the dependency between multiple human failure events (HARR1, AFWOP3, HAMARV) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
TM_1CLR_0300190	2.21E-03	1.021	CCS Pumps and AFW Pump Space Cooler A Maintenance	This term represents the maintenance unavailability of the CCS Pumps and AFW Pump Space Cooler A. Phase II SAMA 289 to install a backup room cooling train was evaluated.
%662.0-1_026_F	3.84E-02	1.019	HPFP FLOOD EVENT IN 662.0-1 AFFECTS THE TB DISTRIBUTION BOARDS - Initiator	This event represents the initiator for a flood in the Turbine Building which originates from High Pressure Fire Protection system piping. This flood impacts the Turbine Building electrical distribution boards. Phase II SAMA 285, to protect equipment in the Turbine Building from internal flooding effects has been evaluated.
TM_U2PMP0740020	5.33E-03	1.019	RHR Pump 2A-A in Test or Maintenance	This term represents the maintenance unavailability of RHR Pump 2A-A. Phase II SAMA 278 improving the reliability of the RHR pumps has been evaluated.
%690.0-A01-4_062_S	2.36E-04	1.018	CVCS SPRAY EVENT IN 690.0-A1 - Initiator	This event represents the initiator for a CVCS spray event in partition 4 of room 690.0-A1. Phase II SAMA 289 to install spray shields for the AFW and BAT Pump Space Coolers has been evaluated.

Table E.1-4 - Correlation of Unit 2 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
HXRPL2_IEF_CCS_HX_ 2A1/2_&_OB1/2	6.29E-05	1.017	IE FREQENCY FOR CCF OF HEAT EXCHANGER 2A1/2 AND 0B1/2 PLUGGING	This term represents the initiating event frequency for the common cause failure of both the train 2A and train 0B component cooling heat exchangers plugging. This event leads to the total loss of component cooling system initiator (%2CCSTL). Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.
%690.0-A01-1_067_F_0A	8.77E-04	1.016	ERCW FLOOD EVENT IN 690.0-A1-1 FROM A DISCHARGE - Initiator	This event represents the initiator for an ERCW flood event in partition 1 of room 690.0-A1. This initiator results in isolation of ERCW header and loss of component cooling water and RCP seal cooling. Phase II SAMA 215 to provide an independent seal cooling system has been evaluated.
%690.0-A01-2_067_F_1B	5.98E-05	1.016	ERCW flood event in 690.0-A01-2 from the 1B-B header with no isolation. - Initiator	This event represents the initiator for an ERCW flood event in partition 2 of room 690.0-A1. This initiator results in isolation of ERCW header and loss of component cooling water and RCP seal cooling. Phase II SAMA 215 to provide an independent seal cooling system has been evaluated.
PSRFD2PMP_0740020	3.66E-03	1.016	Residual Heat Removal Pump Fails to Start (2-PMP-074-0020)	This event represents the random failure of RHR Pump 2B-B to start. No new SAMA identified. Phase I SAMA 44 for using air cooled motors for ECCS pumps has been implemented. Phase II SAMA 278 improving the reliability of the RHR pumps has been evaluated.
U2_02RHRPSRFD_1_2	1.49E-04	1.016	CCF of two components: PSRFD2PMP_0740010 & PSRFD2PMP_0740020	This term represent the common cause failure of the RHR pumps to start. Phase I SAMA 44 for using air cooled motors for ECCS pumps has been implemented. Phase II SAMA 278, improving the reliability of the RHR pumps, has been evaluated.
%2TTIE	1.94E-01	1.015	TURBINE TRIP	This term represents a plant initiator due to a turbine trip. Phase I SAMA 225 to upgrade main turbine controls has been implemented. Phase II SAMA 218 to improve the reliability of power supplies has been evaluated.

Table E.1-4 - Correlation of Unit 2 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
COMBINATION_1942	1.92E+01	1.015	HEP dependency factor for HARR1,HAFR1	This term is a factor that accounts for the dependency between multiple human failure events (HARR1, HAFR1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
U0_CAS02CMPSR_1_2	2.20E-03	1.015	CCF of two components: ACPFR0CMP_0320060 & ACPFR0CMP_0320086	This term represents the common case failure of ACAS Compressors A and B to run. Phase II SAMAs 70, 87, 188 to increase reliability of air systems and coping capability on their loss have been evaluated.
%690.0-A01-4_067_M_2A	1.39E-04	1.013	ERCW MAJOR FLOOD EVEN IN 690.0-A01-4 FROM 2A-A HEADER - Initiator	This event represents the initiator for an ERCW major flood event in partition 4 of room 690.0-A1. This initiator results in isolation of ERCW header and loss of component cooling water and RCP seal cooling. Phase II SAMA 215 to provide an independent seal cooling system has been evaluated.
U2_04AFWPORFO_ALL	1.06E-04	1.013	CCF of all components in group 'U2_04AFWPORFO'	This term represents the common cause failure of all four SG atmospheric relief valves to fail to open on demand. Phase II SAMA 276 to reduce the likelihood of common cause failure of SG atmospheric relief valves was evaluated.
%2PLMFW	1.53E-01	1.012	Partial Loss of Main Feedwater	This initiating event represents the partial loss of main feedwater. Phase I SAMAs 65, 77 and 221 have been implemented or determined to have excessive implementation cost. Phase II SAMA 68 has been evaluated.
COMBINATION_1149	1.79E+02	1.012	HEP dependency factor for HACD2,HAOB2	This term is a factor that accounts for the dependency between multiple human failure events (HACD2, HAOB2) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
COMBINATION_1408	5.31E+02	1.012	HEP dependency factor for HAFR2,HAOB2,HAFR1	This term is a factor that accounts for the dependency between multiple human failure events (HAFR2, HAOB2, HAFR1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.

Table E.1-4 - Correlation of Unit 2 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
COMBINATION_213	2.09E+04	1.012	HEP dependency factor for HASE2,HARR1,AFWOP3,HAMARV	This term is a factor that accounts for the dependency between multiple human failure events (HASE2, HARR1, AFWOP3, HAMARV) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
U2_CRI	1.20E-06	1.012	UNIT 2 CONTROL RODS FAIL TO INSERT	This term represents the hardware failure of control rods to insert when required. Phase II SAMA 277 to improve the reliability of the control rods has been evaluated.
%662.0-1_026_F-1	3.84E-02	1.011	HPFP FLOOD EVENT IN 662.0-1 DOES NOT AFFECT THE TB DISTRIBUTION BOARDS - Initiator	This event represents the initiator for a flood in the Turbine Building which originates from High Pressure Fire Protection system piping. This flood does not impact the Turbine Building electrical distribution boards. Phase II SAMA 285, to protect equipment in the Turbine Building from internal flooding effects has been evaluated.
%690.0-A01-2_067_F_0A	3.47E-05	1.011	ERCW FLOOD IN 690.0-A1-2 FROM A DISCHARGE - Initiator	This event represents the initiator for an ERCW flood event in partition 2 of room 690.0-A1. This initiator results in failure of seal cooling due to loss of component cooling. Phase II SAMA 215 to provide an independent seal cooling system has been evaluated.
AFWOP3_FL	5.00E+00	1.011	FLOODING MULTIPLIER FOR AFWOP3	This term is used to add a stress factor because of flooding to human failure event AFWOP3. Phase II SAMA 279 to improve internal flooding response has been evaluated.
%0LOSP-WI	4.06E-03	1.01	Loss of Offsite Power (Weather Induced)	This term represents the loss of offsite power sources due to weather related events affecting all sources of offsite power. Phase 1 SAMAs addressing power reliability and coping capability for SBO that have been implemented or determined to have excessive implementation cost include SAMAs 1, 2, 3, 4, 9, 10, 13, 22, 23, 24, 67, 173, 176, 216, 229 and 244. Phase II SAMAs 70, 167, 215, 226, and 240 to improve coping capability during an SBO have been evaluated.

Table E.1-4 - Correlation of Unit 2 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
%2SSBO-1	2.93E-03	1.01	SECONDARY SIDE BREAK OUTSIDE CONTAINMENT-SG 1	This event represents secondary side break outside containment initiator. Important actions associated with this initiator are failure to terminate safety injection (SSIOP) and failure to align high pressure recirculation (HARR1). Phase I SAMAs 31, 36, and 247 to improve reliability of recirculation have been implemented. Phase II SAMAs 32, 103 and 283 for automatic recirculation and improved operator training have been evaluated.
%2SSBO-2	2.93E-03	1.01	SECONDARY SIDE BREAK OUTSIDE CONTAINMENT-SG 2	This event represents secondary side break outside containment initiator. Important actions associated with this initiator are failure to terminate safety injection (SSIOP) and failure to align high pressure recirculation (HARR1). Phase I SAMAs 31, 36, and 247 to improve reliability of recirculation have been implemented. Phase II SAMAs 32, 103 and 283 for automatic recirculation and improved operator training have been evaluated.
%2SSBO-3	2.93E-03	1.01	SECONDARY SIDE BREAK OUTSIDE CONTAINMENT-SG 3	This event represents secondary side break outside containment initiator. Important actions associated with this initiator are failure to terminate safety injection (SSIOP) and failure to align high pressure recirculation (HARR1). Phase I SAMAs 31, 36, and 247 to improve reliability of recirculation have been implemented. Phase II SAMAs 32, 103 and 283 for automatic recirculation and improved operator training have been evaluated.
%2SSBO-4	2.93E-03	1.01	SECONDARY SIDE BREAK OUTSIDE CONTAINMENT-SG 4	This event represents secondary side break outside containment initiator. Important actions associated with this initiator are failure to terminate safety injection (SSIOP) and failure to align high pressure recirculation (HARR1). Phase I SAMAs 31, 36, and 247 to improve reliability of recirculation have been implemented. Phase II SAMAs 32, 103 and 283 for automatic recirculation and improved operator training have been evaluated.

Table E.1-4 - Correlation of Unit 2 Level 1 Risk Significant Terms to SAMAs (Based on CDF)				
Event Name	**Probability**	**RRW**	**Event Description**	**Disposition**
%690.0-A01-4_026_F	1.35E-04	1.01	HPFP FLOOD EVENT IN 690.0-A01-4 - Initiator	This event represents the initiator for a HPFP flood event in partition 4 of room 690.0-A1. This initiator results in the loss of AFW pumps. Phase II SAMA 068 to install an additional feedwater pump has been evaluated.
%690.0-A01-4_067_M_2B	1.39E-04	1.01	ERCW MAJOR FLOOD EVEN IN 690.0-A01-4 FROM 2B-B HEADER - Initiator	This event represents the initiator for an ERCW major flood event in partition 4 of room 690.0-A1. This initiator results in the loss of AFW pumps. Phase II SAMA 068 to install an additional feedwater pump has been evaluated.
%690.0-A01-4_067_F_2B	1.16E-04	1.009	ERCW FLOOD EVEN IN 690.0-A01-4 FROM 2B-B HEADER - Initiator	This event represents the initiator for an ERCW flood event in partition 4 of room 690.0-A1. This initiator results in the loss of AFW pumps. Phase II SAMA 068 to install an additional feedwater pump has been evaluated.
AHUFD2CLR_0300176	2.23E-03	1.009	Air Handling Unit (Standby) Fails to Start (2-CLR-030-0176)	This event represents the failure of RHR Pump 1B-B Room air handling unit failure to start. Phase II SAMA 160 to improve coping capability for the loss of room cooling has been evaluated.
COMBINATION_850	2.68E+01	1.009	HEP dependency factor for HACD1,HAOB2	This term is a factor that accounts for the dependency between multiple human failure events (HACD1, HAOB2) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
TM_2PMP_0030128	5.72E-03	1.009	MDAFW PUMP 2B-B IN MAINTENANCE	This term represents the maintenance unavailability of motor driven AFW Pump 2B-B. Phase I SAMA 223 to improve the reliability of the AFW pumps and valves has been implemented.
U2_02RHRAHUFD_1_2	8.12E-05	1.009	CCF of two components: AHUFD2CLR_0300175 & AHUFD2CLR_0300176	This term represents the common cause failure of the RHR Pump 2A-A and 2B-B pump room coolers to start. Phase II SAMA 160 to improve coping capability for the loss of room cooling has been evaluated.
%2LDAAC	1.00E+00	1.008	Loss of 120V AC Vital Instrument Board I	This term represents the failure of the 120V AC Vital Instrument Board I. Phase I SAMAs 7 and 16, which improve the reliability of 120V AC have been implemented. Phase II SAMA 8 for improving training on loss of 120V AC has been evaluated.

Table E.1-4 - Correlation of Unit 2 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
%2LDBAC	1.00E+00	1.008	Loss of 120V AC Vital Instrument Board II	This term represents the failure of the 120V AC Vital Instrument Board II. Phase I SAMAs 7 and 16, which improve the reliability of 120V AC have been implemented. Phase II SAMA 8 for improving training on loss of 120V AC has been evaluated.
%2TLMFW	9.55E-02	1.008	TOTAL LOSS OF MAIN FEEDWATER	This initiating event represents the total loss of main feedwater. Phase I SAMAs 65, 77 and 221 have been implemented or determined to have excessive implementation cost. Phase II SAMA 68 has been evaluated.
%690.0-A01-1_067_F_2A	8.77E-04	1.008	ERCW FLOOD EVENT IN 690.0-A1-1 FROM 2A-A HEADER - Initiator	This event represents the initiator for an ERCW flood event in partition 1 of room 690.0-A1. This initiator results in isolation of ERCW header and loss of component cooling water and RCP seal cooling. Phase II SAMA 215 to provide an independent seal cooling system has been evaluated.
BUSFR2BDE250ND_D_IE	9.94E-04	1.008	Bus Fails to Operate	This term represents the initiating event failure of the electrical bus associated with Vital Instrument Power Board 2-I (%2LDAAC). Phase I SAMAs 7 and 16, which improve the reliability of 120V AC have been implemented. Phase II SAMA 8 for improving training on loss of 120V AC has been evaluated.
BUSFR2BDE250NF_E_IE	9.94E-04	1.008	Bus Fails to Operate	This term represents the initiating event failure of the electrical bus associated with Vital Instrument Power Board 2-II (%2LDBAC). Phase I SAMAs 7 and 16, which improve the reliability of 120V AC have been implemented. Phase II SAMA 8 for improving training on loss of 120V AC has been evaluated.
CMPSD0CMP_0320060	1.02E-02	1.008	COMPRESSOR A FAILS TO START	This term represents the failure of Auxiliary Control Air System (ACAS) Compressor A to start. Phase II SAMAs 70, 87, 188 to increase reliability of air systems and coping capability on their loss have been evaluated.
CMPSD0CMP_0320086	1.02E-02	1.008	COMPRESSOR B FAILS TO START	This term represents the failure of Auxiliary Control Air System (ACAS) Compressor B to start. Phase II SAMAs 70, 87, 188 to increase reliability of air systems and coping capability on their loss have been evaluated.

Table E.1-4 - Correlation of Unit 2 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
PCOFD2PMP_0700033	2.38E-03	1.008	PUMP B FAILS TO START ON DEMAND	This term represents the failure of component cooling water Pump 1B to start on a demand. Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.
RCPSEAL021	7.90E-01	1.008	RCP SEAL 21 GPM	This term represents a 21 gpm RCP seal leak that occurs as the result of loss of CCS Train A and seal injection. Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45 and 215 have also been evaluated. Phase II SAMAs 55, 56, 226 and 240 to increase reliability of seal injection have also been evaluated.
U2_RPS02RTBFO_1_2	1.38E-06	1.008	CCF of two components: RTBFO2BKRC099KG320A & RTBFO2BKRC099KH320B	This term represents the common cause failure of reactor trip breakers 2-BKRC-099-KE/320-A and 2-BKRC-099-KF/320-B to trip open on demand. Phase II SAMAs 136 and 137 have been evaluated.
%690.0-A01-2_067_F_2B	1.11E-03	1.007	ERCW flood event in 690.0-A01-2 from the 2B-B header with no isolation. - Initiator	This event represents the initiator for an ERCW flood event in partition 2 of room 690.0-A1. This initiator results in failure of seal cooling due to loss of component cooling. Phase II SAMA 215 to provide an independent seal cooling system has been evaluated.
HAOF1	5.40E-03	1.007	Restore main feedwater, following AFW failure GT no SI req'd	This term represents the failure of operators to restore main feedwater, following the failure of AFW and no requirement for safety injection. Phase II SAMAs 103 and 283 to increase training and improve awareness of important operator actions have been evaluated.

Table E.1-4 - Correlation of Unit 2 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
PCOFR2PMP_0700059IE	3.90E-02	1.007	PUMP A FAILS TO OPERATE	This term represents the initiating event frequency of component cooling water Pump A failing to run. It is a contributor to the loss of component cooling water Train A initiator (%2CCSA) and the total loss of component cooling water initiator (%2CCSTL). Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.
TKPRP2TNK_0700063IE	2.41E-05	1.007	SURGE TANK B RUPTURE	This term represents the initiating event frequency for the B surge tank failure due to rupture. This event is a contributor to the loss of component cooling water for Train A and Train B. Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.
%662.0-1_026_M	1.27E-02	1.006	HPFP MAJOR FLOOD EVENT IN 662.0-1 AFFECTS THE TB DISTRIBUTION BOARDS - Initiator	This event represents the initiator for a major HPFP flood in the Turbine Building which originates from High Pressure Fire Protection system piping. This major flood impacts the Turbine Building electrical distribution boards. Phase II SAMA 285, to protect equipment in the Turbine Building from internal flooding effects has been evaluated.
%669.0-A01_067_S	6.08E-03	1.006	ERCW SPRAY EVENT IN 669.0-A1 - Initiator	This event represents the initiator for an ERCW spray event in room 669.0-A1 of the Auxiliary Building. This initiator results in the loss of an AFW pump. Phase II SAMA 068 to install an additional feedwater pump has been evaluated.
COMBINATION_2557	6.64E+00	1.006	HEP dependency factor for HAOF1,HARR1	This term is a factor that accounts for the dependency between multiple human failure events (HAOF1, HARR1 that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
COMBINATION_260	3.33E+02	1.006	HEP dependency factor for HASE2,FLAB67DDF	This term is a factor that accounts for the dependency between multiple human failure events (HASE2, FLAB67DDF) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.

Table E.1-4 - Correlation of Unit 2 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
FLAB67DDF	1.50E-04	1.006	OPERATOR ACTION TO ISOLATE SUPPLY HEADER	This term represents a human action to isolate an ERCW header to stop a flood. Phase II SAMA 279 to improve internal flooding response has been evaluated and 283 to improve awareness for important human actions has been evaluated.
MORXC2FCV_0670146IE	3.90E-04	1.006	FCV 67-146 TRANSFERS CLOSED	This term represents the failure of ERCW valve FCV 67-146, which is in the cooling water return line from the Train A component cooling water heat exchangers. This is a contributor to the loss of component cooling water Train A initiator (%2CCSA) and the total loss of component cooling water initiator (%2CCSTL). Phase I SAMAs addressing CCS reliability or coping capability following failure that have been implemented include SAMAs 50, 51, 52, 59, 61, 156, 157, 259, 260, 262 and 264. Phase II SAMAs 45, 55, and 215 have also been evaluated.
SRVWR2SRV_06800563	1.00E-01	1.006	SAFETY VALVE FAILS TO RESEAT AFTER WATER RELIEF SQN-2-VLV-068-0563	This event represents the failure of one of three pressurizer safety relief valves to reclose following a water (versus steam) pressure relief which then leads to a small LOCA event. Phase II SAMA 284 to reduce probability that the pressurizer safety relief valves fail to close was evaluated.
SRVWR2SRV_06800564	1.00E-01	1.006	SAFETY VALVE FAILS TO RESEAT AFTER WATER RELIEF SQN-2-VLV-068-0564	This event represents the failure of one of three pressurizer safety relief valves to reclose following a water (versus steam) pressure relief which then leads to a small LOCA event. Phase II SAMA 284 to reduce probability that the pressurizer safety relief valves fail to close was evaluated.
SRVWR2SRV_06800565	1.00E-01	1.006	SAFETY VALVE FAILS TO RESEAT AFTER WATER RELIEF SQN-2-VLV-068-0565	This event represents the failure of one of three pressurizer safety relief valves to reclose following a water (versus steam) pressure relief which then leads to a small LOCA event. Phase II SAMA 284 to reduce probability that the pressurizer safety relief valves fail to close was evaluated.
U0_ERW04STRPL_ALL	6.49E-07	1.006	CCF of all components in group 'U0_ERW04STRPL'	This term represents the common cause plugging of the ERCW river water strainers. Phase I SAMA 202 and 264 for enhancing screen wash and for improved procedures for coping with loss of ERCW have been implemented. Phase II SAMA 46 for adding a service water pump has been evaluated.

Table E.1-4 - Correlation of Unit 2 Level 1 Risk Significant Terms to SAMAs (Based on CDF)

Event Name	Probability	RRW	Event Description	Disposition
U2_04AFWPORFO_1_2_3	4.92E-05	1.006	CCF of three components: PORFO2PCV_0010005 & PORFO2PCV_0010012 & PORFO2PCV_00100	This term represents the common cause failure of three of four SG atmospheric relief valves to fail to open on demand. Phase II SAMA 276 to reduce the likelihood of common cause failure of SG atmospheric relief valves was evaluated.
U2_CVC02AHUFD1_1_2	8.12E-05	1.006	CCF of two components: AHUFD2CLR_0300184 & AHUFD2CLR_0300185	This term represents the common cause failure of BAT Pump and AFW Pump Space Coolers A and B to start on demand. Phase II SAMA 160 to implement procedures for temporary HVAC has been evaluated.
COMBINATION_2365	2.63E+01	1.005	HEP dependency factor for HARR1,HAMARV	This term is a factor that accounts for the dependency between multiple human failure events (HARR1, HAMARV) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
PSRFD2PMP_0740010	3.66E-03	1.005	Residual Heat Removal Pump Fails to Start (2-PMP-074-0010)	This term represents the random failure of RHR Pump 2A-A to start. Phase I SAMA 44 for using air cooled motors for ECCS pumps has been implemented. Phase II SAMA 278 improving the reliability of the RHR pumps has been evaluated.
U0_CCS02AHUFR_1_2	8.56E-06	1.005	CCF of two components: AHUFR1CLR_0300190 & AHUFR1CLR_0300191	This term represents the common cause failure of CCS and AFW Pump Space Coolers A and B to run. Phase II SAMA 289 to install a backup room cooling train was evaluated.
U2_0BLOCK	7.50E-01	1.005	Probability that 0 PORVs are blocked	This term represents the fraction of time during plant operation that no PORVs are blocked. This event is related to logic associated with the number of PORVs and safety valves that are required during ATWS events. Since this is the preferable state, no evaluation is necessary.

CDF Uncertainty

The uncertainty associated with CDF was estimated and documented in the uncertainty and sensitivity analysis calculation for SQN PRA (Ref. E.1-1) using the SQN CAFTA Rev 0 model.

The ratio of the 95th percentile CDF to the point estimate CDF is 2.14 for Unit 1 and 2.26 for Unit 2. A conservative uncertainty factor of 2.5 will be used to determine the internal and external benefit with uncertainty SAMA evaluation. While the uncertainty analysis was performed with a truncation of 1E-12/year and the SQN SAMA Model uses a truncation of 1E-11/year, the results are judged acceptable for use in the SAMA analysis. Since there are no differences between the CAFTA Rev 0 Level 1 model and the SQN SAMA Level 1 model, the use of an uncertainty factor greater than the calculated factor provides confidence that the uncertainty is bounded.

E.1.2 PRA Model – Level 2 Analysis

E.1.2.1 Containment Performance Analysis

The SQN Level 2 SAMA PRA model used for the SAMA analysis is based on the model that was revised and updated as part of the conversion from a RISKMAN model to a CAFTA model. The Level 2 model was developed with a focus on the quantification of Large Early Release Frequency (LERF) but does include the development of other endstates. However, the quantification of the non-LERF endstates is not as accurate as would be obtained from a rigorous Level 2 model. The Level 2 SAMA PRA model used for the SAMA analysis reflects the SQN operating configuration and design as of November 30, 2009. .

The method used to develop the Sequoyah Level 2 model is based on enhancements to NUREG/CR-6595 and includes realistic quantification of containment threats resulting from high pressure failure of the reactor vessel, hydrogen deflagrations / detonations, additional detail on the treatment of Interfacing System LOCA (ISLOCA) and induced steam generator tube rupture (I-SGTR). The event tree nodes and split fractions were reviewed to ensure that the consequences, in terms of release frequencies, would be larger than would be expected with a fully developed Level 2 model. Two Containment Event Trees (CET), one for Station Blackout (SBO) and one for Non-SBO events, were developed based on NUREG/CR-6595.

The Level 2 event trees were converted into fault trees and linked to the Level 1 core damage fault trees so that the additional logic was incorporated to model all necessary plant specific features and to provide more accurate quantifications. There are eighteen event tree questions associated with the SBO and non-SBO Level 2 event trees. Most of the questions are applicable to both SBO and non-SBO events. The event tree questions are listed below.

- Question 1: SBO or Non-SBO
- Question 2: Containment Bypassed

- Question 3: Containment Isolated
- Question 4: Break Size (RCS Pressure)
- Question 5: Feedwater Available to SG
- Question 6: Pressure Induced SG Tube Rupture
- Question 7: RCS Depressurization (Early)
- Question 8: Thermally Induced SG Tube Rupture
- Question 9: RCS Depressurization (Late)
- Question 10: Core Damage Stopped Prior to Vessel Failure
- Question 11: Availability of Air Return Fan System
- Question 12: Igniters Available
- Question 13: Hydrogen Detonation
- Question 14:Direct Containment Heating
- Question 15:Containment Failure (Early)
- Question 16: Containment Heat Removal
- Question 17: Basemat Melt-Through
- Question 18: Large Early Release

Each CET sequence was assigned to one of the following endstate categories. The sequences within an endstate category are sequentially numbered in the event tree such that each sequence has a unique endstate number.

1. HLERF - LER that occurs during high pressure sequences
   This endstate is determined from large early releases that have a high RCS pressure.
2. LLERF - LER that occurs during low pressure sequences
   This endstate is determined from large early releases that have a low RCS pressure.
3. ILERF - LER via failure of isolation of containment
   This endstate is the result of failures of containment isolation which lead to a release to the environment. The isolation failure LERF is given its own category because its releases are much larger than those from LLERF and HLERF. A containment isolation failure release may have the opportunity to undergo scrubbing via the containment sprays. Large isolation failures are considered if the line sizes are greater than or equal to 2 inches.
4. BLERF - LER via bypass of the containment

This endstate assesses bypasses of containment that have a release to the environment. The bypass LERF is given its own category because its releases are much larger than those from LLERF and HLERF. A bypass release does not have an opportunity to undergo scrubbing within the containment. However, the SGTR tube rupture cases may have an opportunity for scrubbing.

5. LATE - late release which releases radionuclides into the environment

   This endstate is determined from releases that do not have the potential for early fatalities. Containment typically fails late because of over-pressurization due to loss of heat removal.

6. SERF – Small Early Release

   This endstate is a combination of three types of releases, via bypass of the containment (BSERF), SER via failure of isolation of containment (ISERF) and SER via recovery of AC power (SERF).

   BSERF assesses bypasses of containment that have a release to the environment. These releases are much smaller than LERFs. However, a bypass release does not have an opportunity to undergo scrubbing within the containment. ISERF assesses failures of containment isolation which will lead to a release to the environment. Small isolation failures are considered if the line sizes are less than 2 inches. SERF represents small early releases that occur due to the fission product scrubbing once AC power is recovered. This endstate is only credited in the SBO tree with power recovery and a "not VB" answer to Core Damage Stopped Prior to Vessel Failure.

7. INTACT - an intact containment with no significant release to the environment
   This endstate assesses an intact containment with only minimal releases to the environment from normal containment leakage.

The Level 2 sequences with HLERF, LLERF, BLERF and ILERF endstates are those that contribute to LERF. LERF is an indicator of containment performance from the Level 2 results because the magnitude and timing of these releases provide the greatest potential for early health effects to the public. Using the SQN SAMA Model and a truncation of 1E-12/yr, LERF for Unit 1 is 5.93E-06/yr and 5.89E-06/yr for Unit 2. Unit 1 LERF is ~20% of Unit 1 CDF. Unit 2 LERF is ~16.8% of Unit 2 CDF.

Table E.1-5 and Table E.1-6 provide a correlation between the LERF RRW risk significant events (severe accident phenomenon, initiating events, component failures and operator actions) which are greater or equal to 1.005 from the U1 and U2 LERF results using the SQN SAMA Model. The SAMAs associated with each event are also listed.

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

Event Name	Probability	RRW	Event Description	Disposition
HAHH1	1.70E-03	1.2074	Place Hydrogen igniters in service	This term represents the failure of operators to place the hydrogen igniters into service. Phase I SAMAs 96, 108 and 165 to improve the reliability of the hydrogen igniters have been implemented. Phase II SAMAs 109, 103 and 283 to install a passive hydrogen control system has been evaluated and increase training and awareness of important human actions have been evaluated.
CFE6_U1_L2	1.70E-01	1.2053	CFE6 - LOW PRESSURE, VB, IGN FAILED, ARFS SUCCESSFUL	This event represents the likelihood that containment fails early given that the vessel is at low pressure, the igniters fail and the ARFS is successful. For this specific set of conditions, there is the possibility for containment failure due to ex-vessel steam explosions and a H2 burn but not vessel rocketing. Most of the contribution is due to a H2 burn. Phase I SAMAs 96, 108 and 165 to improve the reliability of the hydrogen igniters have been implemented. Phase II SAMA 109 to install a passive hydrogen control system has been evaluated.
COMBINATION_2309	2.94E+02	1.147	HEP dependency factor for HASE2,HAHH1	This term is a factor that accounts for the dependency between multiple human failure events (HASE2, HAHH1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
HAHH1_FL	2.00E+00	1.1024	FLOODING MULTIPLIER FOR HAHH1	This term is used to add an additional stress factor due to flooding on to human failure event HAHH1. Phase II SAMA 279 to improve internal flooding response has been evaluated.
HAPRZ-SUC	9.00E-01	1.0469	SUCCESS-INTENTIONAL OR UNINTENTIONAL RCS DEPRESS PRE I-SGTR (NON-SBO SEQUENCE)	This event is the compliment of event HAPRZ and represents the success of depressurizing the reactor coolant system. Phase II SAMAs 103 and 283 to increase training and improve awareness of important operator actions have been evaluated.
CFE5_U1_L2	1.00E-02	1.0394	CFE5 - LOW PRESSURE, VB, IGN AND ARFS SUCCESSFUL	This event represents the likelihood that containment fails early given that the vessel is at low pressure, the igniters are successful and the ARFS is successful. For this specific set of conditions, there is only the possibility for containment failure from ex-vessel steam explosions and not from vessel rocketing or H2 burn. Phase 1 SAMA 280 addresses this issue.

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

Event Name	Probability	RRW	Event Description	Disposition
HAPRZ	1.00E-01	1.0318	Depressurization of the RCS using pressurizer PORVs (Level 2 ONLY)	This event represents the failure of operator to depressurize the reactor coolant system using the pressurizer PORVs for non SBO scenarios. The probability for the event is a screening value and is conservative. Phase II SAMAs 103 and 283 to increase training and improve awareness of important operator actions have been evaluated.
TISGTRNOSBO_U1_L2	3.81E-02	1.0318	TI-SGTR (NON-SBO SEQUENCE)	This event represents the phenomenological likelihood for thermally induced SG tube ruptures in Level 2 accident sequences with no heat sink. The probabilities are taken from NUREG-1570. Phase I SAMA 281 addresses this issue.
COMBINATION_1370	1.00E+05	1.0281	HEP dependency factor for HAHH1,HAFR2,HARR1,HAFR1	This term is a factor that accounts for the dependency between multiple human failure events (HAHH1, HAFR2, HARR1, HAFR1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
COMBINATION_1370A	1.93E+00	1.0281	HEP dependency factor for COMBINATION_1370	This term is used to as a work-around to a software issue. Use of this event ensures that the dependency for COMBINATION_1370 is correct. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
EDGFR1GEN10821B_B	2.57E-02	1.0223	DG 1B-B Fails to Run	This event represents the failure of the Unit 1 B-B diesel generator to run for the remaining mission time. Phase I SAMAs 10, 11, 12, 17, 18, 19, 20, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14, 161 and 254 have also been evaluated.
EDGFR1GEN10821A_A	2.57E-02	1.022	DG 1A-A Fails to Run	This event represents the failure of the Unit 1 A-A diesel generator to run for the remaining mission time. Phase I SAMAs 10, 11, 12, 17, 18, 19, 20, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14, 161 and 254 have also been evaluated.
COMBINATION_1573	1.02E+04	1.0215	HEP dependency factor for HAPRZ,HAFR2,HARR1,HAFR1	This term is a factor that accounts for the dependency between multiple human failure events (HAPRZ, HAFR2, HARR1, HAFR1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
EDGFR_SOK_2	1.25E+00	1.0159	EDGFR Stake of Knowledge Factor for a group of 2	This term is a factor used to address the state of knowledge correlation for two diesel generators failing to run. It is used to adjust the frequency of cutsets which contain two EDG fail to run events. Phase I SAMAs 10, 11, 12, 17, 18, 19, 20, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14, 161 and 254 have also been evaluated.
X-WI-SBO7A	2.31E-01	1.0157	Weather related failure to recover offsite power event.	This term represents the failure to recover offsite power to the unit following a weather related loss of offsite power. This term is applied for SBO sequences where both EDGs failed to start, battery failure occurs at 4 hours, RCP seal leak is 21 gpm, AFW operating, and depressurization has not occurred. Phase 1 SAMAs addressing power reliability and coping capability for SBO that have been implemented or determined to have excessive implementation cost include SAMAs 1, 2, 3, 4, 9, 10, 13, 22, 23, 24, 67, 173, 176, 216, 229 and 244. Phase II SAMAs 70, 167, 215, 226 and 240 to improve coping capability during an SBO have been evaluated.
EDGFD1GEN0821B_B	8.81E-03	1.0151	Diesel Generator fails to start and run first hour	This event represents the failure of the Unit 1 B-B diesel generator to start and run for one hour. Phase I SAMAs 10, 11, 12, 17, 19, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14 and 254 have also been evaluated.
EDGFD1GEN0821A_A	8.81E-03	1.0146	Diesel Generator Fails to Start and Run First Hour	This event represents the failure of the Unit 1 A-A diesel generator to start and run for one hour. Phase I SAMAs 10, 11, 12, 17, 19, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14 and 254 have also been evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
X-WI-SBO7E	1.25E-01	1.0145	Weather related failure to recover offsite power event.	This term represents the failure to recover offsite power to the unit following a weather related loss of offsite power. This term is applied for SBO sequences where both EDGs failed to run due to common cause, battery failure occurs at 4 hours, RCP seal leak is 182 gpm, AFW operating and depressurization has not occurred. Phase 1 SAMAs addressing power reliability and coping capability for SBO that have been implemented or determined to have excessive implementation cost include SAMAs 1, 2, 3, 4, 9, 10, 13, 22, 23, 24, 67, 173, 176, 216, 229 and 244. Phase II SAMAs 70, 167, 215, 226 and 240 to improve coping capability during an SBO have been evaluated.
%0LOSP-GR	1.07E-02	1.0144	Loss of Offsite Power (Grid Related)	This term represents the loss of all offsite power to the unit due to transmission grid related issues or failures. Phase 1 SAMAs addressing power reliability and coping capability for SBO that have been implemented or determined to have excessive implementation cost include SAMAs 1, 2, 3, 4, 9, 10, 13, 22, 23, 24, 67, 173, 176, 216, 229 and 244. Phase II SAMAs 70, 167, 215, 226 and 240 to improve coping capability during an SBO have been evaluated.
EDGFR2GEN20822A_A	2.57E-02	1.0143	DG 2A-A Fails to Run	This event represents the failure of the Unit 2 B-B diesel generator to run for the remaining mission time. Phase I SAMAs 10, 11, 12, 17, 18, 19, 20, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14, 161 and 254 have also been evaluated.
X-WI-SBO7B	9.80E-02	1.0133	Weather related failure to recover offsite power event.	This term represents the failure to recover offsite power to the unit following a weather related loss of offsite power. This term is applied for SBO sequences where one EDG failed to start and the other failed to run, battery failure occurs at 4 hours, RCP seal leak is 182 gpm, AFW operating and depressurization has not occurred. Phase 1 SAMAs addressing power reliability and coping capability for SBO that have been implemented or determined to have excessive implementation cost include SAMAs 1, 2, 3, 4, 9, 10, 13, 22, 23, 24, 67, 173, 176, 216 and 244. Phase II SAMAs 70, 167, 215, 226, 229, and 240 to improve coping capability during an SBO have been evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
U0_04_082_EDGFR_DG_1_2_4	9.44E-05	1.0125	CCF of three components: EDGFR1GEN10821A_A & EDGFR1GEN10821B_B & EDGFR2GEN20822A	This event represents the common cause failure to run of the Unit 1 A-A, Unit 1 B-B and Unit 2 A-A diesel generators. Phase I SAMAs 10, 11, 12, 17, 18, 19, 20, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14, 161 and 254 have also been evaluated.
TM_1DG082DG1B-B	1.28E-02	1.0124	Diesel Generator 1B-B Maintenance	This event represents the maintenance unavailability of the Unit 1 B-B diesel generator. Phase I SAMAs 10, 11, 12, 17, 18, 19, 20, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14 and 254 have also been evaluated.
X-WI-1LOOPDGALL	1.14E-01	1.0123	Weather related failure to recover offsite power event.	This term represents the failure to recover offsite power to the unit following a weather related loss of offsite power and the common cause failure of all diesel generators. Phase 1 SAMAs addressing power reliability and coping capability for SBO that have been implemented or determined to have excessive implementation cost include SAMAs 1, 2, 3, 4, 9, 10, 13, 22, 23, 24, 67, 173, 176, 216, 229 and 244. Phase II SAMAs 70, 167, 215, 226 and 240 to improve coping capability during an SBO have been evaluated.
TM_1DG082DG1A-A	1.28E-02	1.012	Diesel Generator 1A-A Maintenance	This event represents the maintenance unavailability of the Unit 1 A-A diesel generator. Phase I SAMAs 10, 11, 12, 17, 18, 19, 20, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14 and 254 have also been evaluated.
EDGFR2GEN0822B_B	2.57E-02	1.0103	DG 2B-B Fails to run	This event represents the failure of the Unit 2 A-A diesel generator to run for the remaining mission time. Phase I SAMAs 10, 11, 12, 17, 18, 19, 20, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14, 161 and 254 have also been evaluated.
HART1	1.40E-03	1.0094	Manually trip reactor, given SSPS fails	This event represents the failure of operators to manually trip the reactor if automatic trips fail. Phase II SAMAs 136, 137, 103, 277 and 283 to add additional methods of tripping reactor and to increase training and improve awareness of important operator actions have been evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
X-WI-SBO3/12E	6.80E-02	1.0094	Weather related failure to recover offsite power event.	This term represents the failure to recover offsite power to the unit following a weather related loss of offsite power. This term is applied for SBO sequences where both EDGs failed to run due to common cause, battery failure occurs at 4 hours, RCP seal leak is 21 gpm or no leak, AFW operating and depressurization has occurred. Phase 1 SAMAs addressing power reliability and coping capability for SBO that have been implemented or determined to have excessive implementation cost include SAMAs 1, 2, 3, 4, 9, 10, 13, 22, 23, 24, 67, 173, 176, 216, 229 and 244. Phase II SAMAs 70, 167, 215, 226 and 240 to improve coping capability during an SBO have been evaluated.
U0_04_082_EDGFR_DG_1_2_3	9.44E-05	1.0091	CCF of three components: EDGFR1GEN10821A_A & EDGFR1GEN10821B_B & EDGFR2GEN0822B_	This event represents the common cause failure to run of the Unit 1 A-A, Unit 1 B-B and Unit 2 B-B diesel generators. Phase I SAMAs 10, 11, 12, 17, 18, 19, 20, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14, 161 and 254 have also been evaluated.
COMBINATION_1310	1.00E+05	1.0077	HEP dependency factor for HAHH1,HAFR2,HAOB2,HAFR1	This term is a factor that accounts for the dependency between multiple human failure events (HAHH1, HAFR2, HAOB2, HAFR1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
COMBINATION_1310A	2.39E+00	1.0077	HEP dependency factor for COMBINATION_1310	This term is used to as a work-around to a software issue. Use of this event ensures that the dependency for COMBINATION_1310 is correct. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
EDGFD2GEN0822A_A	8.81E-03	1.0075	Diesel Generator Fails to Start	This event represents the failure of the Unit 2 A-A diesel generator to start and run for one hour. Phase I SAMAs 10, 11, 12, 17, 19, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14 and 254 have also been evaluated.
NOTRCSDEP2_U1_L2	2.32E-01	1.0075	NO HOT LEG FAILURE PRIOR TO VB GIVEN NO TI-SGTR	This event is the compliment of event RCSDEP2_U1_L2. The RCS is at high pressure for this event. Phase I SAMA 282 to address this issue has been addressed.

Table E.1-5 - Correlation of Unit 1 Level II Risk Significant Terms to SAMAs (Based on LERF)				
Event Name	**Probability**	**RRW**	**Event Description**	**Disposition**
EDGFD_SOK_2	1.14E+00	1.007	EDGFD Stake of Knowledge Factor for a group of 2	This term is a factor used to address the state of knowledge correlation for two diesel generators failing to start. It is used to adjust the frequency of cutsets which contain two diesel generator fail on demand events. Phase I SAMAs 10, 11, 12, 17, 19, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14 and 254 have also been evaluated.
CFE1_U1_L2	6.00E-02	1.0069	CFE1 - HIGH PRESSURE, VB, IGN AND ARFS SUCCESSFUL	This event represents the likelihood that containment fails early given that the vessel is at high pressure, the igniters are successful and the ARFS is successful. For this specific set of conditions, there is only the possibility for containment failure from ex-vessel steam explosions and vessel rocketing but not from H2 burn. Phase 1 SAMA 280 addresses this issue.
RCSDEP2_U1_L2	7.68E-01	1.0065	HOT LEG FAILURE PRIOR TO VB GIVEN NO TI-SGTR	This event represents the phenomenological failure of the RCS hot leg prior to vessel breach and with no thermally induced SG tube ruptures. The event is used to address whether the RCS will depressurize after SG tube challenge but before vessel lower head failure. When the RCS is at a high pressure, RCS boundary failure is a race between the lower head melting process, the potential for TI-SGTR and the potential for a pressurized thermal failure of the hot leg or surge line. The RCS is at low pressure for this event. The probability is taken from NUREG/CR-4551. Phase I SAMA 282 addresses this issue.
TM_2DG082DG2A-A	1.28E-02	1.0064	Diesel Generator 2A-A Maintenance	This event represents the maintenance unavailability of the Unit 2 A-A diesel generator. Phase I SAMAs 10, 11, 12, 17, 18, 19, 20, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14 and 254 have also been evaluated.
COMBINATION_1458	1.28E+04	1.006	HEP dependency factor for HAPRZ,HAFR2,HAOB2,HAFR1	This term is a factor that accounts for the dependency between multiple human failure events (HAPRZ, HAFR2, HAOB2, HAFR1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.

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

Event Name	Probability	RRW	Event Description	Disposition
X-GR-SBO7A	3.30E-02	1.0058	Grid related failure to recover offsite power event.	This term represents the failure to recover offsite power to the unit following a grid related loss of offsite power. This term is applied for SBO sequences where battery failure occurs at 4 hours, RCP seal leak is 21 gpm, AFW operating and depressurization has not occurred. Phase 1 SAMAs addressing power reliability and coping capability for SBO that have been implemented or determined to have excessive implementation cost include SAMAs 1, 2, 3, 4, 9, 10, 13, 22, 23, 24, 67, 173, 176, 216, 229 and 244. Phase II SAMAs 70, 167, 215, 226 and 240 to improve coping capability during an SBO have been evaluated.
%0LOSP-SC	7.38E-03	1.0057	Loss of Offsite Power (Switchyard Centered)	This term represents the loss of all offsite power to the unit due to failures in the switchyard. Phase 1 SAMAs addressing power reliability and coping capability for SBO that have been implemented or determined to have excessive implementation cost include SAMAs 1, 2, 3, 4, 9, 10, 13, 22, 23, 24, 67, 173, 176, 216, 219, 229 and 244. Phase II SAMAs 70, 167, 215, 226 and 240 to improve coping capability during an SBO have been evaluated.
EDGFD1GEN0822B_B	8.81E-03	1.0057	Diesel Generator fails to start	This event represents the failure of the Unit 2 B-B diesel generator to start and run for one hour. Phase I SAMAs 10, 11, 12, 17, 19, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14 and 254 have also been evaluated.
TM_0PMP_0670460A	1.30E-02	1.0051	ERCW PUMP Q-A UNAVAILABILITY	This event represents the test and maintenance unavailability of ERCW pump Q-A. Phase I SAMAs 53, 62, 157, 231, 262 and 264 to improve reliability of ERCW or improve the coping capability of loss of the system have been implemented. Phase II SAMAs 45, 46 and 87 have also been evaluated.

Note: Basic events that are correlated in Table E.1-3 are not listed again in this table.

Table E.1-6 - Correlation of Unit 2 Level II Risk Significant Terms to SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
HAHH1	1.70E-03	1.224	Place Hydrogen igniters in service	This term represents the failure of operators to place the hydrogen igniters into service. Phase I SAMAs 96, 108 and 165 to improve the reliability of the hydrogen igniters have been implemented. Phase II SAMAs 109, 103 and 283 to install a passive hydrogen control system has been evaluated and increase training and awareness of important human actions have been evaluated.
CFE6_U2_L2	1.70E-01	1.221	CFE6 - LOW PRESSURE, VB, IGN FAILED, ARFS SUCCESSFUL	This event represents the likelihood that containment fails early given that the vessel is at low pressure, the igniters fail and the ARFS is successful. For this specific set of conditions, there is the possibility for containment failure due to ex-vessel steam explosions and a H2 burn but not vessel rocketing. Most of the contribution is due to a H2 burn. Phase I SAMAs 96, 108 and 165 to improve the reliability of the hydrogen igniters have been implemented. Phase II SAMA 109 to install a passive hydrogen control system has been evaluated.
COMBINATION_2309	2.94E+02	1.134	HEP dependency factor for HASE2,HAHH1	This term is a factor that accounts for the dependency between multiple human failure events (HASE2, HAHH1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
HAHH1_FL	2.00E+00	1.104	FLOODING MULTIPLIER FOR HAHH1	This term is used to add an additional stress factor due to flooding on to human failure event HAHH1. Phase II SAMA 279 to improve internal flooding response has been evaluated.

Table E.1-6 - Correlation of Unit 2 Level II Risk Significant Terms to SAMAs (Based on LERF)				
Event Name	**Probability**	**RRW**	**Event Description**	**Disposition**
HAPRZ-SUC	9.00E-01	1.07	SUCCESS-INTENTIONAL OR UNINTENTIONAL RCS DEPRESS PRE I-SGTR (NON-SBO SEQUENCE)	This event is the compliment of event HAPRZ and represents the success of depressurizing the reactor coolant system. Phase II SAMAs 103 and 283 to increase training and improve awareness of important operator actions have been evaluated.
CFE5_U2_L2	1.00E-02	1.048	CFE5 - LOW PRESSURE, VB, IGN AND ARFS SUCCESSFUL	This event represents the likelihood that containment fails early given that the vessel is at low pressure, the igniters are successful and the ARFS is successful. For this specific set of conditions, there is only the possibility for containment failure from ex-vessel steam explosions and not from vessel rocketing or H2 burn. Phase 1 SAMA 280 addresses this issue.
HAPRZ	1.00E-01	1.045	Depressurization of the RCS using pressurizer PORVs (Level 2 ONLY)	This event represents the failure of operator to depressurize the reactor coolant system using the pressurizer PORVs for non SBO scenarios. The probability for the event is a screening value and is conservative. Phase II SAMAs 103 and 283 to increase training and improve awareness of important operator actions have been evaluated.
TISGTRNOSBO_U2_L2	3.81E-02	1.045	TI-SGTR (NON-SBO SEQUENCE)	This event represents the phenomenological likelihood for thermally induced SG tube ruptures in Level 2 accident sequences with no heat sink. The probabilities are taken from NUREG-1570. Phase I SAMA 281 to addresses this issue.
COMBINATION_1370	1.00E+05	1.029	HEP dependency factor for HAHH1,HAFR2,HARR1,HAFR1	This term is a factor that accounts for the dependency between multiple human failure events (HAHH1, HAFR2, HARR1, HAFR1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.

Table E.1-6 - Correlation of Unit 2 Level II Risk Significant Terms to SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
COMBINATION_1370A	1.93E+00	1.029	HEP dependency factor for COMBINATION_1370	This term is used to as a work-around to a software issue. Use of this event ensures that the dependency for COMBINATION_1370 is correct. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
COMBINATION_1573	1.02E+04	1.022	HEP dependency factor for HAPRZ,HAFR2,HARR1,HAFR1	This term is a factor that accounts for the dependency between multiple human failure events (HAPRZ, HAFR2, HARR1, HAFR1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
X-WI-1LOOPDGALL	1.14E-01	1.013	Weather related fail to recover offsite power event.	This term represents the failure to recover offsite power to the unit following a weather related loss of offsite power and the common cause failure of all diesel generators. Phase 1 SAMAs addressing power reliability and coping capability for SBO that have been implemented or determined to have excessive implementation cost include SAMAs 1, 2, 3, 4, 9, 10, 13, 22, 23, 24, 67, 173, 176, 216, 229 and 244. Phase II SAMAs 70, 167, 215, 226 and 240 to improve coping capability during an SBO have been evaluated.
X-WI-SBO3/12E	6.80E-02	1.012	Weather related fail to recover offsite power event.	This term represents the failure to recover offsite power to the unit following a weather related loss of offsite power. This term is applied for SBO sequences where both EDGs failed to run due to common cause, battery failure occurs at 4 hours, RCP seal leak is 21 gpm or no leak, AFW operating and depressurization has occurred. Phase 1 SAMAs addressing power reliability and coping capability for SBO that have been implemented or determined to have excessive implementation cost include SAMAs 1, 2, 3, 4, 9, 10, 13, 22, 23, 24, 67, 173, 176, 216, 229 and 244. Phase II SAMAs 70, 167, 215, 226 and 240 to improve coping capability during an SBO have been evaluated.

Table E.1-6 - Correlation of Unit 2 Level II Risk Significant Terms to SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
COMBINATION_915	7.24E+01	1.011	HEP dependency factor for HAPRZ,HARR1,HACD1	This term is a factor that accounts for the dependency between multiple human failure events (HAPRZ, HARR1, HACD1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
EDGFR2GEN0822B_B	2.57E-02	1.011	DG 2B-B Fails to run	This event represents the failure of the Unit 2 B-B diesel generator to run for the remaining mission time. Phase I SAMAs 10, 11, 12, 17, 18, 19, 20, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14, 161 and 254 have also been evaluated.
EDGFR2GEN20822A_A	2.57E-02	1.01	DG 2A-A Fails to Run	This event represents the failure of the Unit 2 A-A diesel generator to run for the remaining mission time. Phase I SAMAs 10, 11, 12, 17, 18, 19, 20, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14, 161 and 254 have also been evaluated.
HART1	1.40E-03	1.009	Manually trip reactor, given SSPS fails	This event represents the failure of operators to manually trip the reactor if automatic trips fail. Phase II SAMAs 136, 137, 103, 277 and 283 to add additional methods of tripping reactor and to increase training and improve awareness of important operator actions have been evaluated.
NOTRCSDEP2_U2_L2	2.32E-01	1.009	NO HOT LEG FAILURE PRIOR TO VB GIVEN NO TI-SGTR (Q9)	This event is the compliment of event RCSDEP2_U1_L2. The RCS is at high pressure for this event. Phase I SAMA 282 to address this issue has been addressed.

Table E.1-6 - Correlation of Unit 2 Level II Risk Significant Terms to SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
X-WI-SBO3/12B	5.20E-02	1.009	Weather related fail to recover offsite power event.	This term represents the failure to recover offsite power to the unit following a weather related loss of offsite power. This term is applied for SBO sequences where one EDG failed to start and the other failed to run, battery failure occurs at 4 hours, RCP seal leak is 21 gpm or no leak, AFW operating and depressurization has occurred. Phase 1 SAMAs addressing power reliability and coping capability for SBO that have been implemented or determined to have excessive implementation cost include SAMAs 1, 2, 3, 4, 9, 10, 13, 22, 23, 24, 67, 173, 176, 216, 229 and 244. Phase II SAMAs 70, 167, 215, 226 and 240 to improve coping capability during an SBO have been evaluated.
CFE1_U2_L2	6.00E-02	1.008	CFE1 - HIGH PRESSURE, VB, IGN AND ARFS SUCCESSFUL (Q15)	This event represents the likelihood that containment fails early given that the vessel is at high pressure, the igniters are successful and the ARFS is successful. For this specific set of conditions, there is only the possibility for containment failure from ex-vessel steam explosions and vessel rocketing but not from H2 burn. Phase 1 SAMA 280 addresses this issue.
COMBINATION_1310	1.00E+05	1.008	HEP dependency factor for HAHH1,HAFR2,HAOB2,HAFR1	This term is a factor that accounts for the dependency between multiple human failure events (HAHH1, HAFR2, HAOB2, HAFR1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
COMBINATION_1310A	2.39E+00	1.008	HEP dependency factor for COMBINATION_1310	This term is used to as a work-around to a software issue. Use of this event ensures that the dependency for COMBINATION_1310 is correct. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.

Table E.1-6 - Correlation of Unit 2 Level II Risk Significant Terms to SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
EDGFR_SOK_2	1.25E+00	1.008	EDGFR Stake of Knowledge Factor for a group of 2	This term is a factor used to address the state of knowledge correlation for two diesel generators failing to start. It is used to adjust the frequency of cutsets which contain two EDG failure to start on demand events. Phase I SAMAs 10, 11, 12, 17, 18, 19, 20, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14, 161 and 254 have also been evaluated.
X-WI-SBO3/12A	9.90E-02	1.008	Weather related fail to recover offsite power event.	This term represents the failure to recover offsite power to the unit following a weather related loss of offsite power. This term is applied for SBO sequences where both EDGs failed to start, battery failure occurs at 4 hours, RCP seal leak is 21 gpm or no leak, AFW operating and depressurization has occurred. Phase 1 SAMAs addressing power reliability and coping capability for SBO that have been implemented or determined to have excessive implementation cost include SAMAs 1, 2, 3, 4, 9, 10, 13, 22, 23, 24, 67, 173, 176, 216, 229 and 244. Phase II SAMAs 70, 167, 215, 226 and 240 to improve coping capability during an SBO have been evaluated.
COMBINATION_2265	6.35E+03	1.007	HEP dependency factor for HAOF1,HAHH1,HARR1	This term is a factor that accounts for the dependency between multiple human failure events (HAOF1, HAHH1, HARR1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
RCSDEP2_U2_L2	7.68E-01	1.007	HOT LEG FAILURE PRIOR TO VB GIVEN NO TI-SGTR	This event represents the phenomenological failure of the RCS hot leg prior to vessel breach and with no thermally induced SG tube ruptures. The event is used to address whether the RCS will depressurize after SG tube challenge but before vessel lower head failure. When the RCS is at a high pressure, RCS boundary failure is a race between the lower head melting process, the potential for TI-SGTR and the potential for a pressurized thermal failure of the hot leg or surge line. The RCS is at low pressure for this event. The probability is taken from NUREG/CR-4551. Phase I SAMA 282 addresses this issue.

Table E.1-6 - Correlation of Unit 2 Level II Risk Significant Terms to SAMAs (Based on LERF)

Event Name	Probability	RRW	Event Description	Disposition
COMBINATION_1458	1.28E+04	1.006	HEP dependency factor for HAPRZ,HAFR2,HAOB2,HAFR1	This term is a factor that accounts for the dependency between multiple human failure events (HAPRZ, HAFR2, HAOB2, HAFR1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
COMBINATION_257	1.00E+05	1.006	HEP dependency factor for HASE2,HAHH1,FLAB67DDF	This term is a factor that accounts for the dependency between multiple human failure events (HAASE2, HAHH1, FLAB67DD7) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
COMBINATION_257A	1.02E+00	1.006	HEP dependency factor for COMBINATION_257	This term is used as a work around to a software issue. Use of this event ensures that the dependency for COMBINATION_257 is correct. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
EDGFD1GEN0822B_B	8.81E-03	1.006	Diesel Generator fails to start	This event represents the failure of the Unit 2 B-B diesel generator to start and run for one hour. Phase I SAMAs 10, 11, 12, 17, 19, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14 and 254 have also been evaluated.
EDGFD2GEN0822A_A	8.81E-03	1.006	Diesel Generator Fails to Start	This event represents the failure of the Unit 2 A-A diesel generator to start and run for one hour. Phase I SAMAs 10, 11, 12, 17, 19, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14 and 254 have also been evaluated.

Table E.1-6 - Correlation of Unit 2 Level II Risk Significant Terms to SAMAs (Based on LERF)				
Event Name	**Probability**	**RRW**	**Event Description**	**Disposition**
TM_2DG082DG2A-A	1.28E-02	1.006	Diesel Generator 2A-A Maintenance	This event represents the maintenance unavailability of the Unit 2 A-A diesel generator. Phase I SAMAs 10, 11, 12, 17, 18, 19, 20, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14 and 254 have also been evaluated.
TM_2DG082DG2B-B	1.28E-02	1.006	Diesel Generator 2B-B Maintenance	This event represents the maintenance unavailability of the Unit 2 B-B diesel generator. Phase I SAMAs 10, 11, 12, 17, 18, 19, 20, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14 and 254 have also been evaluated.
COMBINATION_833	5.08E+02	1.005	HEP dependency factor for HAHH1,HARR1,HACD1	This term is a factor that accounts for the dependency between multiple human failure events (HAHH1, HARR1, HACD1) that occur in the same cutset. Phase II SAMA 283 to improve awareness for important human actions has been evaluated.
EDGFR1GEN10821A_A	2.57E-02	1.005	DG 1A-A Fails to Run	This event represents the failure of the Unit 1 A-A diesel generator to run for the remaining mission time. Phase I SAMAs 10, 11, 12, 17, 18, 19, 20, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14, 161 and 254 have also been evaluated.
EDGFR1GEN10821B_B	2.57E-02	1.005	DG 1B-B Fails to Run	This event represents the failure of the Unit 1 B-B diesel generator to run for the remaining mission time. Phase I SAMAs 10, 11, 12, 17, 18, 19, 20, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14, 161 and 254 have also been evaluated.

Table E.1-6 - Correlation of Unit 2 Level II Risk Significant Terms to SAMAs (Based on LERF)				
Event Name	**Probability**	**RRW**	**Event Description**	**Disposition**
U0_04_082_EDGFR_DG_ALL	1.03E-04	1.005	CCF of all components in group 'U0_04_082_EDGFR_DG'	This event represents the common cause failure to run of the Unit 1 A-A, Unit 1 B-B, Unit 2 A-A and Unit 2 B-B diesel generators. Phase I SAMAs 10, 11, 12, 17, 18, 19, 20, 173, 216, 229 and 244 to increase the reliability of on-site power sources or improve coping capability on their loss have been implemented. Phase II SAMAs 14, 161 and 254 have also been evaluated.

Note: Basic events that are correlated in Table E.1-4 are not listed again in this table.

E.1.2.2 Mapping of Level 1 Sequences

The core damage sequences from the Level 1 PRA are binned into plant damage states (PDS) based on similar characteristics that influence the accident progression following core damage. These PDS determinations were made during the accident sequence analysis (Ref. E.1-13). A description of the bins is included in Table E.1-7. The binning results are utilized to incorporate the Level 1 sequences directly into the Level 2 fault tree. The Level 1 core damage sequences are binned based on their PDS and then mapped to Level 2 sequences. Table E.1-8 through Table E.1-12 tabulate the Level 1 sequences that are associated with each of the bins.

Table E.1-7 - Bin Definitions

Bin Number	Bin Description	PDS	Table
1	Not bypassed (N) High RCS pressure (H) Wet (W) SG	NHW	Table E.1-8
2	Not bypassed (N) High RCS pressure (H) Dry SG (D)	NHD	Table E.1-9
3	Not bypassed (N) Low RCS pressure (L) SG Wet (W) or Dry (D)	NLW NLD	Table E.1-10
4	Large bypass (B) High (H) or Low (L) RCS Pressure SG Dry (D)	BHD BLD	Table E.1-11
5	Small bypass (B) High RCS Pressure (H) SG Wet (W)	BHW	Table E.1-12

Table E.1-8 - Core Damage Sequences for Bin 1 – High RCS Pressure and Wet SG

ATWS-004	SLOCA-005	SSBI-007	SSBO-007
ATWS-008	SLOCA-006	SSBI-008	SSBO-008
ATWS-014	SLOCA-014	SSBI-010	SSBO-010
ATWS-018	SLOCA-016	SSBI-024	SSBO-024
	SLOCA-023	SSBI-025	SSBO-025
	SLOCA-024	SSBI-027	SSBO-027

Table E.1-9 - Core Damage Sequences for Bin 2 – High RCS Pressure and Dry SG

ATWS-003	GTRAN-003	SLOCA-002	SLOCAV-003	SSBI-003	SSBO-003
ATWS-007	GTRAN-004	SLOCA-008	SLOCAV-004	SSBI-004	SSBO-004
ATWS-009	GTRAN-006	SLOCA-009	SLOCAV-006	SSBI-005	SSBO-005
ATWS-010	GTRAN-007	SLOCA-011	SLOCAV-007	SSBI-013	SSBO-013
ATWS-012	GTRAN-008	SLOCA-018	SLOCAV-008	SSBI-014	SSBO-014
ATWS-013	GTRAN-010	SLOCA-019	SLOCAV-010	SSBI-016	SSBO-016
ATWS-016	GTRAN-011	SLOCA-025	SLOCAV-011	SSBI-017	SSBO-017
ATWS-017	GTRAN-013		SLOCAV-013	SSBI-020	SSBO-020
ATWS-019	GTRAN-014		SLOCAV-014	SSBI-021	SSBO-021
ATWS-020	GTRAN-015		SLOCAV-015	SSBI-022	SSBO-022
	GTRAN-021			SSBI-030	SSBO-030
	GTRAN-022			SSBI-031	SSBO-031
	GTRAN-025			SSBI-033	SSBO-033
	GTRAN-026			SSBI-034	SSBO-034
				SSBI-036	SSBO-036
				SSBI-037	SSBO-037
				SSBI-038	SSBO-038

Table E.1-10 - Core Damage Sequences for Bin 3 – Low RCS Pressure

LLOCA-002	MLOCA-003	SLOCA-004
LLOCA-003	MLOCA-004	SLOCA-013
LLOCA-004	MLOCA-005	SLOCA-021
LLOCA-005	MLOCA-006	SLOCA-022
EX1 (Excessive LOCA)	MLOCA-009	
	MLOCA-010	
	MLOCA-011	
	MLOCA-012	
	MLOCA-013	

Table E.1-11 - Core Damage Sequences for Bin 4 – Large Bypasses

ISLM-003	SGTR-003	ATWS-021
ISLM-004	SGTR-006	
ISLM-006	SGTR-009	
ISLM-007	SGTR-012	
ISLM-009	SGTR-014	
ISLM-012	SGTR-015	
ISLM-013	SGTR-018	
ISLM-015	SGTR-021	
ISLM-016	SGTR-024	
ISLM-018	SGTR-027	
ISLM-019	SGTR-029	
	SGTR-030	
	SGTR-033	
	SGTR-036	

Table E.1-12 - Core Damage Sequences for Bin 5 – Small Bypasses

SGTR-034
SGTR-035

Table E.1-8 – E.1-12 Notes:

The sequence names are associated with the type of accident sequence.

Level 1 Sequence Name	*Type of Sequence*
ATWS	Anticipated Transient Without Scram
GTRAN	*General Transient*
LLOCA	*Large LOCA*
MLOCA	*Medium LOCA*
SLOCA	*Small LOCA*
EX1	*Excessive LOCA (Vessel Rupture)*
SSBI	*Secondary Side Break Inside Containment*
SSBO	*Secondary Side Break Outside Containment*
ISLM	*Medium or Large Interfacing System LOCA*
SGTR	*Steam Generator Tube Rupture*

E.1.2.3 Radionuclide Release

E.1.2.3.1 Introduction

Core damage sequences that lead to containment failure and release of radioactive materials to the environment are considered in this section. As previously discussed, the PDS bins are used to incorporate Level 1 core damage sequences directly into the Level 2 sequence logic. Each Level 2 sequence is assigned to an end state representative of the sequence's release magnitude and timing. The determination of the characteristics for each release category is based on representative accident scenarios that reflect the core damage behavior for the dominant sequence or sequences within a plant damage state and the dominant Level 2 sequence within the release category. These core damage accident scenarios then become the major contributors to the release categories associated with each of the containment failure modes.

E.1.2.3.2 Release Categories

The release categories represent a grouping of end state results from the SQN Level 2 PRA. Initially, the endstates were grouped into the following release categories.

- **Release Category I, LERF** – Large Early Releases (LER); containment failures due to severe accident phenomena at or near time of vessel failure. This release category includes Level 2 sequences with HLERF and LLERF endstates.

- **Release Category II, ILERF** – LER due to containment isolation failures; containment isolation failure at or near the time of vessel failure. This release category includes Level 2 sequences with the ILERF endstate.

- **Release Category III, BLERF** – LER due to containment bypass. This release category includes Level 2 sequences with the BLERF endstate.

- **Release Category IV, Late** – Late containment failure release. Containment fails late either from base-mat melt-through or due to loss of containment heat removal. Base-mat melt-through is assigned a probability of zero for SQN because the containment over-pressurizes first in sequences without containment heat removal. This release category includes Level 2 sequences with a Late endstate.

- **Release Category V, SERF** – All early release sequences with some mitigation of release by phenomenological means. This includes small containment isolation failures, small pre-existing containment leaks and SGTR bypass sequences with wet SG. This release category includes sequences with the SERF endstate.

The Intact end state is not included as a release category because it is assumed to have an insignificant impact on the consequences of a severe accident. As previously discussed, the Level 2 model for SQN was developed with a focus on the quantification of LERF but does include the development of other endstates. However, the quantification of the non-LERF endstates is not as accurate as would be obtained from a more rigorous Level 2 model. Normally the total of all endstate release frequencies would be equal to the total CDF. Quantification of the SQN SAMA Model results in release frequencies that are over predicted such that the total of all release frequencies, excluding the Intact endstate, is almost equal to the total CDF for Unit 1. Given this result and the fact that the consequences from an Intact release are significantly lower compared to the consequences of any of the other endstates, it is judged that excluding the intact endstate from the SAMA analysis is reasonable and results in a conservative analysis. The Unit 2 case is similar but not as pronounced. Even so, the same rationale holds, and the conclusion is that it is acceptable to exclude the Intact endstate from the SAMA analysis.

The above categories were subdivided so that each resulting category (or sub-category) was representative of a consistent set of accident conditions (e.g., reactor pressure, containment conditions, timing, etc.). This was necessary because a SEQSOR emulator, developed for the Watts Bar Unit 2 SAMA analysis, was used to determine the source term release fractions.

A SEQSOR emulator was necessary because the SEQSOR program used to calculate the source terms for Sequoyah in NUREG/CR-4551 (Ref. E.1-12) was not available for this analysis. The SEQSOR code was originally developed because of the large number of possible sequences a plant could undergo during an accident. The complexity and time of running a phenomenological code, such as MAAP, for each of these sequences would have been impossible. Instead, the SEQSOR code was developed as a relatively simple parametric code to select from a representative set of results from detailed phenomenological codes as probability distributions. This approach allows one to estimate a large number of cases in a short time.

SEQSOR uses blocks of data containing probability distributions, by release class (the nine release classes are groups of elements with similar chemical behavior) for a variety of terms in the basic SEQSOR equations, given in equations 3.1 and 3.2 of NUREG/CR-4551. Equation 3.1 gives the behavior in the early phase, before the reactor vessel breach (if any). Equation 3.2 gives the behavior in the late phase, which considers the core-concrete interaction. Each of the data blocks represents a term in one or both of these equations and the data in each is a function of a probability level between 0% and 100%, and in most cases is also a function of the radionuclide group. During the Monte-Carlo process, a random variable between 0 and 1 is used to select a value (or a set of values for each radioisotope group) for the calculation. The same data blocks were used in the SEQSOR emulator, except where processes or equipment that needed to be considered for this analysis were not included in the NUREG/CR-4551 analyses. The SEQSOR Emulator was developed to use the same SEQSOR logic but in a spreadsheet format. The SEQSOR Emulator was independently reviewed prior to use for WBN-2 SAMA analysis.

The final release categories are listed in Tables E.1-13 and E.1-14 along with their associated dominant Level 2 sequences. The frequency for each release category is determined by quantifying the corresponding top event in the Level 2 portion of the SQN SAMA Model at a truncation of 1E-12/year.

Table E.1-13 - Unit 1 Final Release Categories and Frequencies

Release Category	Dominant Level 2 Sequences	Sequence Frequency	Release Category Frequency
I a – LER; RPV Hi Pressure, LOCA, non-SBO	HLERF-001	4.06E-08	4.06E-08
I b – LER; RPV Lo Pressure, LOCA, non-SBO	LLERF-001	2.04E-08	9.70E-07
	LLERF-002	1.84E-08	
	LLERF-019	1.59E-07	
	LLERF-020	7.72E-07	
I c – LER; RPV Lo Pressure, non-SBO Transient	LLERF-013	4.59E-08	2.65E-07
	LLERF-014	2.19E-07	
II a – Isolation LER; SBO, ATWS	ILERF-002 (83.83%)	3.26E-06	3.26E-06
II b – Isolation LER; SBO, LOCA	ILERF-002 (16.17%)	6.29E-07	6.29E-07
II c – Isolation LER; non-SBO, LOCA	ILERF-001 (57.6%)	6.47E-08	6.47E-08
II d – Isolation LER; non-SBO, Transient	ILERF-001 (42.4%)	4.77E-08	4.77E-08
III – Bypass LER; non-SBO	BLERF-001	1.83E-07	6.43E-07
	BLERF-002	1.10E-08	
	BLERF-003	4.48E-07	
IV a – Late Release; non-SBO, LOCA	LATE-042	1.43E-05	1.79E-05
	LATE-044	3.65E-06	
IV b – Late Release; non-SBO Transient	LATE-034	2.23E-06	2.23E-06
V a – SER; Lo Pressure, LOCA	SERF-001 (64.7%)	2.08E-06	2.08E-06
V b – SER; High Pressure, LOCA/Transient	SERF-001 (35.3%)	1.13E-06	1.13E-06

Table E.1-14 - Unit 2 Final Release Categories and Frequencies

Release Category	Dominant Level 2 Sequences	Frequency	Release Category Frequency
I a – LER; RPV Hi Pressure, LOCA, non-SBO	HLERF-001	4.55E-08	4.55E-08
I b – LER; RPV Lo Pressure, LOCA, non-SBO	LLERF-001	2.31E-08	9.53E-07
	LLERF-002	1.93E-08	
	LLERF-019	1.54E-07	
	LLERF-020	7.57E-07	
I c – LER; RPV Lo Pressure, non-SBO Transient	LLERF-013	9.45E-08	3.86E-07
	LLERF-014	2.91E-07	
II a – Isolation LER; SBO, ATWS	ILERF-002 (91%)	3.30E-06	3.30E-06
II b – Isolation LER; SBO, LOCA	ILERF-002 (9%)	3.26E-07	3.26E-07
II c – Isolation LER; non-SBO, LOCA	ILERF-001 (48.1%)	6.26E-08	6.26E-08
II d – Isolation LER; non-SBO, Transient	ILERF-001 (51.9%)	6.76E-08	6.76E-08
III – Bypass LER; non-SBO	BLERF-001	2.54E-07	7.41E-07
	BLERF-002	2.31E-08	
	BLERF-003	4.63E-07	
IV a – Late Release; non-SBO, LOCA	LATE-042	1.38E-05	1.74E-05
	LATE-044	3.60E-06	
IV b – Late Release; non-SBO Transient	LATE-034	1.24E-06	1.24E-06
V a – SER; Lo Pressure, LOCA	SERF-001 (51.1%)	2.01E-06	2.01E-06
V b – SER; High Pressure, LOCA/Transient	SERF-001 (48.9%)	1.92E-06	1.92E-06

E.1.2.3.3 Timing and Other Release Characteristics

Additional characteristics of the release categories are required as inputs to the Level 3 analysis. These include release timing, duration, energy and warning time of the release.

Timing governs the extent of radioactive decay of short-lived radioisotopes prior to an off-site release and, therefore, has a first-order influence on immediate health effects. The release timing is characterized relative to the time at which the release begins and is measured from the time of accident initiation. Since no release category specific accident progression analyses were available, the timing of the different release categories has been based on the dominant Level 1 and 2 accident sequence definitions. For releases defined as early by the Level 2 analysis, the assumption is that the containment fails at essentially the time of vessel failure. Based on MAAP calculations, vessel failure is assumed to occur in approximately 4 hours following the loss of core cooling (Ref. E.1-2). Therefore, any sequence with successful core cooling prior to loss of injection will have additional time until the vessel and containment fail; thereby, delaying the release to the environment. This additional time is conservatively determined based on the most limiting thermal hydraulic analysis associated with the dominant Level 1 accident sequence for the release category. Release Category III, Bypass, is an exception. The dominant Level 1 sequence for Release Category III is an un-mitigated ATWS event and only 2 hours from accident initiation to release is assumed.

The warning time from start of the sequence for the early release sequences is generally assumed to be one hour after the time that cooling to the RCS is lost. The Late release categories assume a warning time of 12 hours. This is because the containment does not fail due to phenomena associated with vessel failure but fails due to lack of heat removal from the containment. Failure of the containment from loss of heat removal occurs at 19 hours from initiation of the accident (Ref. E.1-2). Therefore, a conservative time of 12 hours has been assumed. This assumption accounts for the possibility that knowledge of the status and capability of the containment could influence the Emergency Response Organization to delay elevating the emergency levels until it was clear that restoration of containment heat removal was not going to be successful.

The duration of all releases is conservatively assumed to be 2 hours. This maximizes the impact of the releases on public health.

The energy of releases is based on that of similar accident scenarios from the NUREG/CR-4551 analysis of Sequoyah. Twenty-eight megawatts is assumed for early containment failure categories while four megawatts is assumed for the bypass, late and small early release categories.

Table E.1-15 - Release Category Characteristics

Release Category	Time of Release (hours)	Warning Time (hours)	Release Duration (hours)	Release Energy (Mw)	Release Height (meters)	Noble	I	Cs	Te	Ba	Sr	Ru	La	Ce
RC I a	5	2	2	28	20	8.5E-01	2.8E-02	1.9E-02	2.0E-02	9.8E-03	1.5E-02	9.9E-03	8.8E-03	9.9E-03
RC I b	5	2	2	28	20	8.5E-01	1.3E-02	1.0E-02	1.5E-02	8.6E-03	1.5E-02	9.7E-03	8.5E-03	8.6E-03
RC I c	6	3	2	28	20	8.5E-01	1.3E-02	1.1E-02	1.5E-02	8.9E-03	1.5E-02	9.8E-03	8.7E-03	8.9E-03
RC II a	4	1	2	28	20	8.5E-01	9.0E-02	5.1E-02	3.9E-02	1.4E-02	1.2E-02	7.4E-03	8.2E-03	1.5E-02
RC II b	5	2	2	28	20	8.4E-01	8.8E-02	4.9E-02	3.8E-02	1.3E-02	1.1E-02	7.2E-03	8.1E-03	1.3E-02
RC II c	5	2	2	28	20	8.5E-01	9.3E-03	7.5E-03	1.0E-02	6.1E-03	1.0E-02	6.8E-03	5.9E-03	6.1E-03
RC II d	4	1	2	28	20	8.5E-01	2.1E-02	1.4E-02	1.5E-02	7.2E-03	1.1E-02	7.0E-03	6.4E-03	7.3E-03
RC III	2	1	2	4	20	8.5E-01	2.6E-01	1.5E-01	8.1E-02	2.7E-02	1.4E-02	8.3E-03	1.2E-02	2.9E-02
RC IV a	19	12	2	4	20	8.5E-01	2.7E-03	2.3E-03	4.6E-03	2.3E-03	4.8E-03	2.6E-03	2.3E-03	2.3E-03
RC IV b	19	12	2	4	20	8.5E-01	2.3E-03	2.1E-03	4.1E-03	2.0E-03	4.4E-03	2.4E-03	2.1E-03	2.0E-03
RC V a	5	2	2	4	20	8.5E-03	1.3E-04	1.3E-04	1.7E-04	1.5E-04	1.9E-04	1.6E-04	1.5E-04	1.5E-04
RC V b	6	3	2	4	20	8.5E-03	8.7E-05	1.1E-04	1.5E-04	1.4E-04	1.9E-04	1.6E-04	1.5E-04	1.4E-04

E.1.3 IPEEE Analysis

E.1.3.1 Seismic Analysis

SQN performed a Seismic Margins Assessment (SMA) following the IPEEE guidance of NUREG-1407 (Ref. E.1-3) and the seismic margins methodology of EPRI NP-6041-SL (Ref. E.1-4). The SMA approach is a deterministic and conservative evaluation that does not calculate risk on a probabilistic basis. Therefore, its results should not be compared directly with the best-estimate internal events results.

The conclusions of the SQN IPEEE seismic margin analysis are as follows:

- The equipment reviewed for SQN during the systematic evaluation of the seismic event proved to be overall rugged in nature and of a sufficient capacity to provide assurance of continued functionality for the Review Level Earthquake (RLE).
- This systematic evaluation of the seismic event performed by the Seismic Margins Method has provided adequate evidence of the ability of SQN to resist a significant seismic event up to the RLE and be able to initiate a safe shutdown of the unit. Therefore, the potential for core damage, containment failures, or off site releases are considered acceptably low. No specific vulnerabilities to the seismic event were noted other than a few specific areas of improvement. The plant improvements are identified in NUREG-1742 as replacement of MCC anchorages; upgrade of RHR heat exchanger anchorages; and corrective change to eliminate interactions. All of these improvements have been implemented.
- The original evaluation determined that the RHR heat exchangers had a High Confidence, Low Probability of Failure (HCLPF) of 0.27g. Modifications were made and the heat exchangers are no longer considered low capacity components. No other unique decay heat removal vulnerabilities to seismic events were found. See Section E.1.3.4 for additional discussion of this issue.
- As originally evaluated, assuming a ground level RLE of 0.3g, the overall plant HCLPF capacity at SQN was determined to be at least 0.27g. In response to an NRC request for additional information (RAI), certain components were re-evaluated assuming a RLE defined by a NUREG/CR0098 spectral shape anchored to 0.30g at rock. The limiting recomputed component HCLPF values range from 0.23g to 0.29g (Ref. E.1.3.4).

E.1.3.2 Fire Analysis

TVA performed an analysis of internal fires using the Fire Induced Vulnerability Evaluation (FIVE) (Ref. E.1-6) methodology for Unit 1. FIVE is fundamentally a prescriptive fire PRA-based screening approach, which uses progressively more detailed phases of screening. Most of the SQN fire areas were screened in the early screening phase. The CDF of the areas in the final phase of screening totaled 1.56E-05/yr.

A revised fire IPEEE was developed in response to NRC RAIs. This evaluation was able to screen more areas because of additional walkdowns and cable routing information resulted in more credit for feed and bleed cooling and the use of fire severity factors. The conclusion of the analysis was that all rooms were screened from further consideration and it was confirmed that there are no fire-induced vulnerabilities associated with the continued operation of the Sequoyah Nuclear Plant. The total CDF of the areas remaining in the final phase of screening for this revision is 5.83E-06/yr. Table E.1-16 provides a summary of the final phase of screening results from the SQN IPEEE fire analysis.

No changes to the physical configuration, maintenance, operating and emergency procedures, surveillance, staffing, or training programs were identified due to the evaluations performed for the internal fire event. No plant improvements were identified as a result of the SQN IPEEE fire analysis.

E.1.3.3 Other External Hazards

The SQN IPEEE submittal, in addition to the internal fires and seismic events, examined a number of other external hazards:

- high winds and tornadoes;
- external flooding; and
- transportation, and nearby facility incidents

SQN performed the screening described in Supplement 4 to General Letter 88-20 and NUREG-1407 to address the other external hazards. Because SQN was designed prior to the 1975 Standard Review Plan (SRP) the approach taken was to review the design bases and compare them to the SRP requirements. Any changes to the plant since the design analyses were performed were also reviewed to verify compliance with SRP criteria. It was found that no vulnerabilities exist for other external events which are not within the screening thresholds of the SRP. The IPEEE evaluation revealed that the plant meets the 1975 SRP criteria for these external events and no recommendation for plant improvements results.

E.1.3.4 SAMA External Events Multiplier

Since there are no up to date quantitative external events models for SQN, it is necessary to develop a multiplier that can be applied to the internal events PRA results to account for the risk contribution from external events in SAMA evaluations.

As indicated above, the SQN "other" external events were addressed by demonstrating compliance with the 1975 SRP. Compliance with the SRP and no adverse finds from walkdowns, justifies the conclusion that the hazard's contribution to CDF is less that 10^{-6} per year. Therefore, these events are not significant dominant contributors to external event risk and since quantitative analysis of these events is not practical, the external event multiplier will be developed based on seismic and fire risk. This is consistent with the guidance of NEI-05-01 (Ref. E.1-7).

SQN used a SMA method to address seismic risk and thus no seismic core damage estimate was developed. However, there is a relatively current estimate for the seismic risk for SQN which was developed by the NRC as part of its work to address Generic Issue 199, "Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern U.S. for Existing Plants." These results are provided in a safety/risk assessment that the NRC performed for addressing GI-199 (Ref. E.1-8). This assessment determined that the weakest link model seismic risk for SQN 1 and 2 is 5.1E-05 per year. While this may be conservative estimate, it was used to develop the external event multiplier for the SAMA evaluations.

The conclusion of the SQN Five analysis was that all rooms were screened from further consideration and there are no fire-induced vulnerabilities associated with the continued operation of the Sequoyah Nuclear Plant. However, the core damage estimates for the areas in the final phase of screening are typically used to represent the fire risk. Table E.1-16 provides a listing of those areas and their associated CDF which totals to 5.83E-06/yr.

Therefore, the external event multiplier for SQN Unit 1 is determined as follows:

EE Multiplier = (Internal Event CDF + Fire CDF + Seismic CDF)/Internal Event CDF

= (2.96E-05 + 5.83E-06 + 5.1E-05)/2.96E-05

= 2.9

The SQN Unit 2 external event multiplier is:

EE Multiplier = (3.51E-05 + 5.83E-06 + 5.1E-05)/3.51E-05

= 2.6

Table E.1-16 - SQN Fire IPEE

Fire Areas Included in Final Phase of Screening	
Significant Fire Area	**Total Compartment CDF (/yr)**
Corridor	9.78E-07
Main control room/control room	9.33E-07
Corridor	5.53E-07
Unit 2 auxiliary instrument room	3.83E-07
Unit 1 auxiliary instrument room	3.76E-07
Cable spreading room (only or upper)	3.67E-07
Electrical equipment room/auxiliary relay room	3.66E-07
480-V board room 1B	3.58E-07
250-V battery board room 1 & 2 and corridor	2.54E-07
480-V board room 2B	2.50E-07
480-V shutdown board room 1B2	1.90E-07
480-V shutdown board room 2A2	1.77E-07
Computer room	1.58E-07
6.9kV shutdown board room B	1.54E-07
Mechanical equipment room	8.21E-08
Auxiliary control room	8.01E-08
250-V battery room No. 1	5.69E-08
480-V shutdown board room 1A2	4.45E-08
Personnel and equipment access room	4.38E-08
6.9kV shutdown board room A	1.95E-08
480-V shutdown board room 1A1	1.07E-08
Total	5.83E-06

Note 1. This listing is consistent with the listing provided in Table 3.3 of NUREG-1472, Vol. 2 except the NUREG table erroneously includes an area (Turbine room/hall/building—CDF=6.78E-07) that was not included in the last phase of SQN screening.

E.1.4 PRA Model Revisions and Peer Review Summary

A summary of the SQN PRA models CDF and LERF is presented in the table below.

Table E.1-17 - Summary of Major PRA Models

PRA Model	CDF (/ry)		LERF (/ry)		Issue Date
	Unit 1	Unit 2	Unit 1	Unit 2	
IPE	1.7E-04	1.7E-04[1]	2.72E-06	2.72E-06[1]	9/1/1992
Revision 1	3.8E-05	3.8E-05[1]	6.08E-07	6.08E-07[1]	9/1995
Revision 2	6.31E-06	6.31E-06[1]	1.14E-07	1.14E-07[1]	9/2000
Revision 3	1.31E-05	1.31E-05[1]	2.62E-07	2.62E-07[1]	9/2003
Revision 4	1.75E-05	1.75E-05[1]	3.94E-07	3.94E-07[1]	6/2006
PRA CAFTA Revision 0[2]	3.02E-05	3.59E-05	4.39E-06	4.63E-06	6/3/2011
SQN SAMA Model[3]	2.96E-05	3.51E-05	5.93E-06	5.89E-06	

Note 1. The same model used to represent both units.
Note 2. CDF truncation of 1E-12/yr. LERF truncation of 1E-13/yr.
Note 3. CDF truncation of 1E-11/yr. LERF truncation of 1E-12/yr.

E.1.4.1 Major Differences between the Revision 1 PRA Model and the IPE Model

Among the more significant of the plant changes incorporated during the first revision to the IPE were the following:

- Incorporation of a design change which added a crosstie line from the 480V Board Room 1A to the 480V Board Room 1B and a crosstie line from 480V Board Room 2A to the 480V Board Room 2B such that room cooling for the 120V AC inverters is supplied by two ventilation systems rather than one.
- The re-quantification of operator action "Align High-Pressure Recirculation, Given Auto Swapover Succeeds" due to revision of the procedures and training programs at SQN applicable to this operator action.
- Revision of the success criteria for CCS Train A from requiring two operating pumps, or one pump and operator action to isolate spent fuel pool cooling to requiring one pump for successful operation of CCS Train A if CCS Train A is not supporting spent

fuel pool (SFP) loads, or one if SFP is supported by CCS Train A and the event is a general transient without an induced LOCA.

- Removing the requirement for CCS mechanical seal cooling for successful operation of the SI, RHR, and centrifugal charging pumps.

E.1.4.2 Major Differences between the Revision 2 Model and the Revision 1 Model

Revision 2 to the Sequoyah IPE was performed with the primary intent of updating plant data to reflect the current operating reliability for various plant components, as tracked by the Maintenance Rule program. A secondary objective was to review the plant model to more accurately reflect actual plant operation following reactor trip.

Initiating event frequencies were also updated based on more current industry information contained in "Rates of Initiating Events at U.S. Nuclear Power Plants: 1987 - 1995 (NUREG/CR-5750). In general, this resulted in a lowering of analyzed reactor and plant trip frequencies.

The following major plant and plant model changes were incorporated in the course of this update:

- The steam generator level control valves for the turbine driven AFW pump have been modified to fail open on a loss of plant air.
- The success criteria for bleed and feed cooling was revised to require one PORV. This removed several of the previously dominant scenarios resulting from loss of battery board and failure of the available AFW train, since bleed and feed cooling was previously set to guaranteed failure under these conditions.
- The RCP seal failure and electric power recovery models were reviewed against current plant and industry data.
- The modeling of ERCW strainer maintenance was reviewed and revised. This effectively removed two of the previously dominant scenarios resulting from ERCW intake flooding and assumed failure of the unaffected train of ERCW due to performing maintenance on one of the system strainers.
- The risk model quantification cutoff value was lowered from 1E-9 to 1E-12 to provide a more robust scenario database.

Finally, a separate event tree module was incorporated to allow plant model quantification to generate the large early release frequency (LERF) directly from the Level 1 plant model.

E.1.4.3 Major Differences between the Revision 3 Model and the Revision 2 Model

As with Revision 2, Revision 3 to the Sequoyah IPE was performed with the primary intent of updating plant data to reflect the current operating reliability for various plant components, as tracked by the Maintenance Rule program. Initiating event frequencies were also updated to include the more recent plant experience.

The following major plant and plant model changes were incorporated in the course of this update:

- Updated the human action analysis, using the EPRI HRA calculator to estimate human error rates. This represented the first major update to operator action reliability since the initial submittal in 1992.
- Reactor trip failure (ATWS) and steam generator tube rupture (SGTR) were separated into individual event tree modules.
- The various systems analyses were reviewed with plant system engineers to confirm current system installation and operation and if necessary changes were made to the system modeling or success criteria.
- The Plant Compressed Air fault trees were revised to address the replacement of the C and D air compressors with new, higher capacity, units.

E.1.4.4 Major Differences between the Revision 4 Model and the Revision 3 Model

Revision 4 to the SQN Plant PRA Model was completed to incorporate plant specific data collected by the Maintenance Rule program and comments made by the plant system engineers. Additional changes were made to the model to permit calculation of Fussel-Vesely importance values of certain maintenance alignments in support of the MSPI program. All human actions were verified, updated and re-evaluated using EPRI HRA Calculator Version 3.0.

The documentation for the Revision 4 SQN PRA was altered from the original IPE format. A series of Notebooks were developed to document every aspect of the PRA Model. These notebooks are designed to reflect the structure of the ASME RA S-2002, *Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications.*

E.1.4.5 Major Differences between the CAFTA Revision 0 Model and the Revision 4 Model

This was a complete revision of the model that involved converting the model from the RISKMAN software platform into CAFTA format. This involved assembling the model from the ground up, including initiating event frequencies, component failure data, human failure events, accident sequence event trees and system fault trees. A detailed internal flooding analysis was also performed. The revised model was peer-reviewed in February of 2011.

E.1.4.6 Major Differences between the SQN SAMA Model and the CAFTA Revision 0 Model

The SQN SAMA Model is a relatively minor revision of the CAFTA Revision 0 Model which was made to address some modeling concerns with the Level 2 portion of the model. These model revisions were made because the quantification of isolation large early release sequences did not include internal flood induced station blackout isolation failures as expected. The relatively minor modification ensured that Level 1 sequences with large containment isolation failures were properly accounted for in isolation LERF Level 2 sequences. The success logic of the Level 2 sequences was also added to the model to improve the quantification of individual release categories. Additional top logic was added to the Level 2 model to group sequences for the quantification of release categories in the SAMA analysis. No changes were made to the Level 1 portion of the model logic.

This model used a higher truncation for both the Level 1 and LERF quantification in order to speed the quantification of SAMA evaluations. A PRA model is subject to a number of approximations. One of these approximations is because cutsets generated by the Boolean logic are truncated during the quantification process. This truncation limit is established due to both computational time and computer storage capacity limitations.

As part of a PRA model update, the quantification of a model is typically evaluated to assess the adequacy of the truncation level chosen. The PRA Application Guide (Ref. 6.20) and the NEI Peer Review Process (NEI 00-02) (Ref. 6.23) identify the use of truncation values of four (4) orders of magnitude below the CDF (or LERF) for a high quality PRA. In addition, the ASME/ANS PRA Standard (Ref. 6.24) includes a supporting requirement (QU-B3) for establishing the truncation limit:

> "ESTABLISH truncation limits by an iterative process of demonstrating that the overall model results converge and that no significant accident sequences are inadvertently eliminated. For example, convergence can be considered sufficient when successive reductions in truncation value of one decade result in decreasing changes in CDF or LERF, and the final change is less than 5%."

The following tables include CDF and LERF values for different levels of truncation for the Unit 1 and 2 SQN SAMA Models.

SQN Unit 1 SAMA Model Truncation

Truncation Frequency	CDF	% Change CDF	LERF	% Change LERF
1.00E-09	2.39E-05	-	-	-
1.00E-10	2.79E-05	16.74	5.35E-06	-
1.00E-11	2.96E-05	6.03	5.72E-06	6.82
1.00E-12	3.02E-05	2.14	5.93E-06	3.71
1.00E-13	-	-	6.06E-06	2.24

SQN Unit 2 SAMA Model Truncation

Truncation Frequency	CDF	% Change CDF	LERF	% Change LERF
1.00E-09	2.80E-05	-	-	-
1.00E-10	3.30E-05	18.14	5.35E-06	-
1.00E-11	3.51E-05	6.24	5.72E-06	6.82
1.00E-12	3.59E-05	2.14	5.93E-06	3.71
1.00E-13	-	-	6.06E-06	2.24

The results in the above tables indicate that both CDF and LERF for both units converge relatively quickly as the truncation limit is reduced. The truncation of LERF at 1E-12/yr clearly meets the QU-B3 supporting requirement of the ASME/ANS PRA standard. The CDF convergence delta is ~6 percent for a truncation of 1E-11/yr, which is slightly above the supporting requirement delta of 5 percent. This truncation level is well below the guidance of EPRI TR-105396 and NEI 00-02 (four orders of magnitude below the CDF) and maintains the typical one order of magnitude truncation between CDF and LERF. Reducing the truncation to 1E-12/yr results in a ~2% increase in CDF. Since the SAMA analysis is driven by the Level 2 results, reducing the CDF truncation an additional decade would not result in a significant difference in results. Based on these observations, a truncation level of 1E-11/yr for CDF is judged to be acceptable for use in SAMA analysis.

E.1.4.7 PRA Model Peer Review

Regulatory Guide (RG) 1.174, 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.

A peer review of the January 14, 2011 version of the internal events SQN CAFTA PRA, including internal flooding was performed in 2011. The peer review assessed the model against the ASME/ANS PRA Standard (ASME/ANS RA-Sa-2009) and Regulatory Guide 1.200 Revision 2. The overall conclusions of the SQN Peer review are provided below:

> "The review of the SQN PRA was completed with the attached documentation. The outstanding issues primarily pertain to quantification results and documentation issues. The overall conclusions of the peer review team regarding the SQN PRA are as follows:
>
> - The overall model structure is robust and well-developed, but needs refinement,
> - Documentation is thorough, detailed, and well organized such that comparison with the standard is facilitated,

- The processes and tools utilized for the SQN PRA are at the state of the technology and generally consistent with Capability Category II, and
- The PRA maintenance and update program includes all necessary processes and does a very good job of tracking pending changes.

The SQN PRA does meet the ASME/ANS PRA Standard. The SQN PRA has issues which have been documented in Appendix C and should be addressed to improve the quality of the PRA model." (Ref. E.1-9)

The findings from the Peer review have been addressed, incorporated in the model, and are considered resolved. Changes required as a result of resolving findings were incorporated into the CAFTA Revision 0 model which was approved on June 3, 2011. Summaries of the findings and their resolution are provided below (Ref. E.1-10).

Finding 1-4

Summary:

MDN-000-000-2010-0203 does not document an assessment of the impact of flooding events on existing Human Failure Events (HFEs) carried over from the internal events scenario used to represent the flooding event.

Resolution:

To address human actions and their modification due to flooding events Section 9.3 was added to the document. Section 9.3 addresses the changes to the human actions in the model by accounting for:

Human actions that are influenced by HRA actions, these are events that occur within an hour of flood initiation.

Human actions that are failed due flooding.

Finding 1-7

Summary:

Dependency analysis was performed for the post-initiator HEPs using the EPRI HRA Calculator. However, several issues were identified including:

Use of the same cue for two actions can result in conservative dependency values. For example, the use of the same cue for actions HARR1 and AFWOP3 resulted in complete dependency between the actions. However, review of the cues indicated that the cue for AFWOP3 should be different than that for HARR1.

Inconsistent entry of the timing information creates results that may appear invalid. For example, the timing entries for actions HARR2 and AFWOP3 make it appear that core damage as a result of failure of HARR2 would occur before the cue for AFWOP3 is received. Discussion revealed that the Tsw for HARR2 is based on the time at which the RWST would empty rather than core damage as stated in the HRA Calculator.

Inclusion of screening HFEs in the dependency analysis can result in errors. The screening HEPs do not have information that is necessary for the dependency analysis (e.g., timing inputs). This can result in the wrong event being treated as the independent event in the combination. For example, review of dependency combination 41 shows that the dependency analysis treats HACD1 as the first or independent HFE in the combination and AFWOP5 as following HACD1. This results in a joint HEP of 1.0 based on complete dependency. However, the description of HFE HACD1, "Perform cooldown with main feedwater following AFW failure," indicates that AFWOP5 should be the first event. This would result in a joint HEP of 2.9E-03.

The dependency level of the cognitive recoveries were not entered in the HRA Calculator database for the post-initiators. This requires manual entry by the analyst and does not default to the recommended dependence level. Failure to enter this information may underestimate or overestimate the HEP depending on the applicable dependence level.

Some of these items were corrected during the review but they are documented in an F&O due to the need to evaluate the extent of the condition.

Resolution: Cue for AFWOP3 has been updated to correct cue. Review has been performed for all remaining actions to determine if any additional cues need to be updated. This review verified the accuracy of HRA cues and updated six of the identified cues.

The end point for Tsw is an irreversible damage state. For HARR2, this irreversible damage state is the loss of all ECCS pumps when the RWST is depleted and autoswap has failed. This is the correct irreversible damage state as the operator does not have until core damage to perform that action if the pumps fail when their suction source runs dry. The dependency analysis was reviewed for overlapping timeframes.

Screening value HEPs were removed from the database if there values were set to 1.0. The HEPs that were originally in the model were no longer required and were deleted from the fault tree.

This has been corrected for all of the actions in the SQN HRA.

Finding 1-8

Summary:

MDN-000-000-2010-0203 Section 9.5 only addresses quantification and results for CDF. There is no discussion of LERF for the flooding scenarios or documentation indicating that the flood scenarios were reviewed to determine if they would have an impact on the Level 2 CETs. The linked fault tree model should have the capability to produce LERF results, but this had not been done at the time of the review. In addition, there was no discussion in the Level 2 Notebook (MDN-000-000-2010-0206) that indicates the results include the internal flood scenarios.

Resolution:

The internal flooding calculation was revised to add Section 10 (Results Analysis for Large Early Release Frequency).

Section 10.1 addresses the eighteen questions concerning LERF and their impact.

Section 10.3 and 10.4 address the LERF results due to flooding.

To address the additional information the following Appendices were added to the model:

Appendix Q - Significant Cutset Review for Large Early Release

Appendix R - Non-Significant Cutset Review for Large Early Release

Appendix S - Importance Reports for Large Early Release

Finding 1-10

Summary:

MDN-000-000-2010-0206 Section 5.6 notes that credit was taken for scrubbing of releases from a ruptured SG. However, the technical justification for this credit needs to be strengthened. The current basis compares the zero power collapsed level to the top of the SG tubes. However, ES-3.1, Post-SGTR Cooldown Using Backfill allows the level in the ruptured SG to be between 20% narrow range and 75% narrow range during the cooldown (Step 7). The expected levels during SGTR recovery should be used to justify the scrubbing credit.

It also appears that the analysis implicitly assumes that if FW will be applied to the ruptured SG if FW is available. No consideration of operator failure to provide FW flow to the ruptured generator is included in the analysis.

Resolution:

The documentation has been updated to include a discussion of the water levels above the steam generator tubes during tube rupture recovery actions. These water levels (between 4.7 and 9.8 feet) should be sufficient to take credit for fission product scrubbing. This analysis assumes that the operator is successful in providing feedwater flow to the ruptured steam generator.

Finding 1-11

Summary:

The total LERF is compared with other Westinghouse 4-loop plants and with other Ice Condenser plants. However, there is no comparison at the level of significant contributors or plant damage states. Without the contributor information, it is not really possible to determine how similar the LERF results are to other plants.

Resolution:

The documentation has been updated to include comparisons by initiating event for several other PWRs in Table 11-7

Finding 1-14

Summary:

Demand data is obtained directly from the plant process computer for most components, as described in Section 7.3 of the data notebook (MDN-000-000-20100202). The status change information from the computer is filtered and used to determine the number of demands.

The use of automatic data collection, however, means that start and run events that occur in all modes of operation are included. In addition, post-maintenance test starts are also included in the data set. This is identified as a source of uncertainty in the sensitivities and uncertainties notebook (MDN-000-000-2010-0209) and a specific set of sensitivity studies were performed that assumed that various numbers of successful starts were invalid. The results show that the impact on CDF is relatively small, unless the number of successful starts is overestimated by a large amount. However, this SR is explicit in its requirement to not count post-maintenance test events.

Resolution:

The work orders for the components that were credited for success in the data analysis were reviewed to discover the number of post maintenance tests that were performed on the components. Table 15 was added to document the number of post maintenance tests that were removed from the analysis.

Finding 1-15

Summary:

The super initiator "general transient" may overlook certain differences among its contributors. For example, the impact of specific IEs like LOSP and Loss of DC that may prevent PORV operation and challenge the Pressurizer Safeties do not appear to be captured.

In addition, failure to provide a separate event tree for SBO may overestimate the success of power recovery by not addressing the operation of systems such as charging and AFW following power recovery.

Resolution:

GTRAN was restructured to address this comment. The tree was updated to explicitly ask demand for PORVs and Safeties

Finding 1-19

Summary:

It was noted that HFE HAPRZ (discussed in Section 6.8 and Section 7.2) is not calculated using HRA Calculator. This event seems to have been carried over from the Watts Bar analysis and is treated as basic event U1_L2_NOTRCSDEPNOSBO.

In addition, although Section 6.8 says that the No RCS Dep branch is set to a value of 1 for SBO cases, the value of basic event U1_L2_NOTRCSDEPSBO in the provided MASTERL2.CAF fault tree was set to 0.9995. This also appears to be a carryover from Watts Bar.

Resolution:

The current analysis has been updated to change the value of failure to depressurize the RCS during SBO scenarios to 1.0 (assumed failure) in the model. The basic event HAPRZ, which represents failure to depressurize for non-SBO scenarios, uses a value of 0.1 for failure to depressurize, which was taken from WCAP 16341-P, revision 0. The level 2 event trees also use the compliment to this action called HAPRZ-SUC which has a probability of 0.9.

Finding 2-1

Summary:

Section 7.0 of the Initiating Events Analysis observes a decreasing trend in initiator frequency in the more recent generic data sources. However, there is no comparison of the SQN results against the generic results, nor an explanation of any significant differences.

Resolution:

Added text to initiating events notebook that compares Sequoyah initiator frequencies to generic industry data.

Finding 2-3

Summary:

Section 4.3.1 of the Data Analysis notebook discusses the basic event probability model methodology. Generic data sources selected for use are applicable for SQN.

For those components which had a failure during the analysis time period (1/1/03 - 11/30/09), the distributions are updated via the Bayesian update program built into CAFTA program. However, the intent of this supporting requirement is to assure realistic parameter estimates are calculated for SIGNIFICANT basic events based on relevant generic and plant-specific evidence, not just those for which failures have occurred. Where no failures have occurred, use of the generic data may be conservative since it includes failures from potentially less reliable components across the industry.

Resolution:

Significant contributors that were not Bayesian updated were identified as: BATFR - Battery Fails to Operate BUSFR - Bus Fails to Operate CBKFO - Circuit Breaker Fails to Open FNSFD - Standby fan fails to start HXRPL - Heat Exchanger (River Water) Plugs or Fouls MOCXC - Motor Operated Valve Transfers Closed POEFR - ERCW pumps fail to run PSRFR - RHR pumps fail to run STRPL - Strainers plug TSCPL - Traveling water screens plug XRFR - Transformer fails to operate

These events were Bayesian updated using plant specific data. The notebook has been updated to reflect these additional updates.

Finding 2-4

Summary:

Appendix F of the Data Analysis notebook provides graphs that show the prior and posterior distributions. Table 19 lists generic and Bayesian-updated mean values, along with a ratio of the posterior to prior mean value. However, there are no conclusions drawn about whether or not the posterior distributions are reasonable given the relative weight of evidence provided by the prior and the plant-specific data. (Note: the statement that "There are no significant differences between the industry data from NUREG/CR-6928 and the posterior distributions for the SQN failure rates" in section 11.0 is not judged to be sufficient. For example, the ratio of the posterior to prior mean for the AHUFR type code in Table 19 is 10.6. For type code LSTFR, the ratio is 4.3. The significance of these differences should be discussed.)

Resolution:

The posterior distributions were validated using the following process. Using a Monte Carlo simulation, the posterior distributions were samples to see the probability of having a recurrence in the number of events observed in the data window given the number of successes in the data window. If the mean value was within 0.05 to 0.95 the resultant distribution was used within the model. Appendix F was re-written to address this analysis as well as to present the prior, posterior, and plant specific distributions.

Finding 2-5

Summary:

The method from NUREG/CR-6823 is used to Bayesian-update a Jeffrey's non-informative prior distribution with plant-specific experience. However, there is no comparison of the posterior means to plant-specific means. (See the last sentence in NUREG/CR-6823, section 6.7.1.2.)

Resolution:

The fundamental assumption used in the Bayesian update process described in the Data Analysis notebook for unavailability calculations is that there is no prior information from which to Bayesian update. Therefore, the methodology used was to use a Jeffery's non-informative prior (0.5) as the foundation for the update process. All of the available data that was used was from plant specific data collection, therefore the posterior mean and plant specific mean are directly correlated. The following assumption was added to Section 3.0 to address the non-informative prior.

"For unavailability calculations, a Jeffery's non-informative prior was used as there was no informative prior information available."

Finding 2-8

Summary:

The importance of components and basic events are identified in sections 5.1 and 5.7 of the Accident Sequence notebook, respectively. However, documentation that determined the importance results make logical sense could not be identified.

Resolution:

A review of the importance of components and basic events has been performed to determine that they make logical sense. The review shows that the risk significant components are consistent with the model results and limitations. Significant contributors include basic events associated with diesels, ERCW, Component Cooling, RHR, Atmospheric Relief Valves (ARVs) and Air Compressors. In SQN, Failure of the auxiliary control air headers impacts the ARVs that are needed to cooldown/depressurize in LOCA scenarios since the condenser is unavailable from Phase B isolation. The emergency diesel, ERCW, RCP breakers, and RHR are important since their failure result in scenarios involving SBO and RCP seal LOCAs.

Finding 3-1

Summary:

Section 4.5, "The calculation above provides that the containment 'hole' size must lie between a 1 inch equivalent path and a 4 inch path. Therefore, it is acceptable to use the NRC value of 2 inches." Based on the statement, the 1" equivalent hole should have been considered.

Resolution:

Section 4.4 discusses the reasoning for concluding that the 2" hole size is acceptable for use in the Sequoyah level 2 analysis. The reference shows that the release rate corresponding to a 1771 scfm rate would be represented by a vent line diameter greater than 1" and slightly less than 2". Because the point corresponding to 1771 scfm at 19 psig (which is half of the assumed severe containment challenge pressure) is only slightly below the 2" contour line shown in Reference 33, and there is conservatism built into both the assumed containment failure pressure and the assumed leak rates at that pressure, it is judged appropriate to use 2" as the bounding value for a large leak rate.

Finding 3-7

Summary:

Several areas were identified that need additional discussion with respect to the Success Criteria Analysis. For example:

1) The differences between plant response to a pipe-break SLOCA and a consequential PORV LOCA are not fully discussed. Given the differences in break location, there should be some discussion in the Success Criteria Notebook of why the pipe-break SLOCA analyses bound the consequential PORV LOCA. In addition, while there is a discussion in the TH Notebook comparing the values of some key parameters for the pipe-break SLOCA and the consequential PORV LOCA, this does not fully explore differences in plant response that may affect the success criteria.

2) There needs to be more discussion of why the 480 gpm per pump RCP Seal leaks are included in the Medium LOCA (MLOCA) grouping. It is stated in Section

4.4.10 of the TH Notebook that the 480 gpm seal LOCA meets the MLOCA requirement of not requiring AFW for accident mitigation, but there is no documentation of success criteria analyses that support this statement.

3) The basis for assuming a SGTR flow of 700 gpm in Section 7.2.10 of the TH Notebook needs to be discussed in more detail than simply noting that no historic SGTR has been of the magnitude of a double-ended guillotine rupture of a SG tube.

4) The LOCA analysis is limited to the upper and lower end of the break range for each class. TH analysis at the middle of the break range within the Large, Medium, and Small LOCA categories may provide insights that have not been revealed by the upper and lower end of the break. For instance, it is not clear if sequence MLOCA-011 can be a success path for a break in the 3 to 5 inch range.

Resolution:

1) The small LOCA events assume that he break occurs low within the physical structure of the RCS. These breaks will always have a higher deltaP value than those of breaks at the top of the RCS (PORV LOCA). Due to the additional pressure and other thermo-hydraulic characteristics the success criteria is bounding for the SLOCA cases.

2) The 480 gpm seal LOCA is now grouped as a SLOCA. This requires the use of AFW for successful accident mitigation.

3) The value of 700 gpm was used as an attempt to bound the analysis. The selection of 700 gpm was done to assure that the analysis was realistic in nature, but conservative as well.

4) The MLOCA event tree has been restructured to require successful injection of the CLAs this is to assure that any break size within the MLOCA range can be successfully mitigated after failure of the CVCS system to inject.

Finding 3-9

Summary:

All mitigation strategies credited in the accident sequence model when the high pressure recirculation has failed are not prescribed by the corresponding EOPs. In other words, the mitigation credit in the event tree model has no basis. This issue has been self identified by the SQN PRA staff and a corrective action report has been written for the EOP group to resolve this issue. At this stage the PRA group "firmly" believes that the EOP will be modified, not the model. Thus it is a tracking issue.

Resolution:

EOP revisions were approved at the SQN PORC meeting on May 6th 2011.

Finding 3-13

Summary:

Section 4.4.2 of the TH Notebook (MDN-000-000-2010-205) discusses the use of MAAP for LLOCA in the cold leg. The conclusion is that the large LOCA (LLOCA) limitations are not applicable to break sizes < 10 inches. The reference used for this is a MAAP training lecture. Use of MAAP to model the injection phase of the LLOCA needs additional justification with reference to the applicable technical documents.

Resolution:

The limitations noted for MAAP are for the larger end of the LLOCA spectrum per EPRI TR-1020236. The success criteria for the large LOCA was consistent with and largely derived from the SQN design basis analysis and SAR. While this does lead to conservative results in the LLOCA event tree, the expenditure of additional resources for the further refinement using additional codes such as RELAP is not warranted, given that LLOCA events are not risk significant in the SQN model. The low importance of the LLOCA sequences is consistent with other PWRs in the industry.

The MAAP analysis for the LLOCA events were used mostly as confirmation of the event trees based on the SQN SAR and for timing of HRA events. Specifically for the HRA events, MAAP was only used to determine depletion of the RWST and long term time to core damage based on failure of hot leg recirculation. Both of these cases are significantly past the initial stages of a LLOCA where MAAP is noted to lack the thermal hydraulic detail required to evaluate the initial blowdown (EPRI-TR1020236).

Finding 3-14

Summary:

Several documentation issues were noted in the Success Criteria and TH Notebooks. Specifically,

1) Figures 7-60 and 7-61 of the TH Notebook (MDN-000-000-2010-205) need to be replaced with updated results.

2) The discussion of accident sequence node LPH in Section 7.3.1 of the TH Notebook (MDN-000-000-2010-205) states that "The time for switchover to hot leg recirculation is specified in the EOP E-1 as 3 hours after the initiation of a large LOCA (Reference 4, Step 31c)." In the paragraph immediately below this statement, the calculation of the time available for recovery from a failure of recirculation uses a switchover time of 5 hours. Discussion with TVA personnel indicated that the 3 hour value was copied from the WBN notebook. The actual time specified in the SQN procedures is 5 hours.

3) Table 7-13 of the TH Notebook (MDN-000-000-2010-205) does not include success path ISLM-014 as shown in Figure 6.4-10 of the Accident Sequence Notebook (MDN-000-000-2010-0201). In addition, success path ISLM-017 in Table 7-13 of the TH Notebook is not shown in Figure 6.4-10 of the Accident Sequence Notebook.

4) Section 4.4.11 of the TH Notebook (MDN-000-000-2010-205) discusses the classification of a Stuck Open PORV as a small LOCA. The basis needs to be provided.

Resolution:

1) Figures 7-60 and 7-61 were revised in the TH calculation MDN-000-000-2010-205. In the original MAAP runs, the SG ARVs were opened at 30 minutes, this dropped pressure in the RCS. Opening of the SG ARV was not credited in the event tree for the sequences evaluated in figures 7-60 and 7-61. This is applicable to the WBN TH analysis as well.

2) The TH Notebook was revised to be consistent with EOI E-1 step 22. The correct time of switching over to Hot Leg Recirculation of 5 hours was included in Section 7.3.1 of the TH Notebook.

3) Table 7-13 and Figures 6.4-10 were revised to be consistent.

4) Additional information was included in section 4.4.11 of the TH notebook to justify the classification of a Stuck Open PORV. This information includes a comparison of core damage timing and mass/energy release rates through a SOPORV and SLOCA.

Finding 3-19

Summary:

Section 7.2 of the HRA Notebook (MDN-000-000-2010-0204) does not explicitly discuss how the required and available manpower is addressed in the analysis. Manpower requirements are included in the operator interview checklist as item 37. However, it is not clear how this information was used in the development of the HEPs since some instances were observed where the operator interview responses were not used in the HRA calculator (see HFE HARR1).

Resolution:

A discussion of the required and available manpower to perform the actions and equipment manipulations was documented in sections 7.1 and 7.2 of the HRA notebook. Also, HARR1 was revised to match the operator interview for the manpower requirements.

Finding 3-20

Summary:

Several issues related to the TH analyses used to support the HRA were identified. Specifically,

1) Some time windows are buried in MAAP output files which are not included in the TH Notebook and take time to review. For example, the time window for AFWOP5 is not easily available.

2) TH Notebook MDN-000-000-2010-205 Section 7.3.3 discusses the actions required following a failure of high pressure recirculation. The required action related to failure of the automatic recirculation alignment (HARR1) has two big pieces. The first is to stop the pump to avoid pump damage. If the pumps are damaged, high pressure recirculation can't be successful. The time window is short for this action and is related to RWST depletion. If the pumps are stopped on time the next action is to manually establish recirculation. The time window for that action is based on the RCS inventory depletion which is, relatively speaking, much longer.

If HP recirculation is not successful, the RCS is depressurized to facilitate low pressure recirculation (AFWOP3). These two actions (HP recirculation and RCS depressurization and establish LP injection/recirculation) are for the same mitigation function. Therefore, it is unclear why there are big differences between the time windows for these two actions. In addition, the HRA Calculator input for these actions appears to be different from the descriptions in Section 7.3.3 of MDN-000-000-2010-205.

3) The use of bounding analyses for the HFEs results in non sequence specific timing information in the HRA. For example, HARR1 is used in the accident sequences after AFWS success in SSBO and SSBI accident sequences. However, the timing window of HARR1 is based on the medium LOCA and it is conservative for these sequences.

Resolution:

1) TH notebook revised – all HRA timing in Table 8.1

2) All TH result cases were reviewed to ensure that the time windows in use were consistent between different actions with the same purposes.

3) As stated in the details of the F&O, the analysis used is conservative. The timing analysis is for the most time limiting break for which the action is applied. This conservative timing selection addresses all potential scenarios/break sizes and would only reduce HEP and add additional margin to the analysis. This is considered to be appropriate due to the ranges of break sizes included in the broad bands of initiating event groupings. Evaluation of the recovery of additional margin from developing lower HEP individual analyses for each application of HARR1 will be completed in future revisions of the SQN PRA model.

Finding 3-25

Summary:

Several documentation issues were noted. For example:

1) Sequences ISLM-008 and ISLM-017 were deleted from the ISLOCA event tree. However, there is no discussion of why this was done.

2) Paragraphs in section 6.4.7 need to be revised. Specifically, the first sentence in the first paragraph on page 62, starting with "If the temperature of the RCS is 557°F and dropping, the steam dumps, S/G PORVs and blowdown isolation valves are closed." needs to be finished. There is the "if" but no "then." It is also unclear how this sentence is related to the accident sequence event tree or the following statements in the paragraph related to the PORVs.

The second paragraph on page 62 has grammatical errors (e.g., "…the possibility of have a RCP Seal LOCA…").

3) The discussion of manual control rod insertion following ATWS in section 7.9 needs to be revised to reflect the intent to remove credit for this action from the model.

Resolution:

1) The sequences were not re-numbered following the latest update to the event trees. The numbering scheme will be updated in the next revision of the notebook.

2) The grammatical errors noted have been updated and revised.

3) The ATWS discussion of MRI has been updated to state that only the mechanical binding of the control rods or the failure of the automatic control system are modeled.

Finding 4-3

Summary:

Non-water flood sources are excluded on the basis of Assumption 11 of the notebook. However, the Standard states (in Note 1 for this SR) that non-water sources should be considered, A more detailed basis for excluding these sources should be developed to meet the requirements of this SR.

Resolution:

Assumption 11 was reworded to:

All sources of fluid within the plant were analyzed for flooding considerations. However, the glycol system is the only system which could have an impact on the flooding analysis. All other sources such a resin did not have enough volume to cause impact to plant operation. The glycol system also has a minimum volume, but the location of the piping, in the control rod drive rooms, causes system to be a source of spray initiating events.

Finding 4-7

Summary:

No discussion of sources of uncertainty associated with the flooding initiating events is currently provided in the flooding notebook (MDN-000-000-2010-0203). It is noted that the notebook includes documentation of sources of uncertainty for other portions of the flooding analysis. Sources of model uncertainty for internal flooding are also documented in MDN-000-000-2010-0209, Uncertainty and Sensitivity Analysis; however, again flood initiator uncertainties are not discussed. If no uncertainties are identified for the flood initiator frequency evaluation, then the notebook should state this to be consistent with the approach used for the IFPP, IPSO, and IFSN tasks.

Resolution:

Section 8.8 was added to the Internal Flooding Notebook with the following:

The internal flooding frequency calculation has several different uncertainties associated with the calculation. The current model uses a summation of three different frequencies, passive pipe break failures, human induced floods, and maintenance induced flooding. Each of these flooding events has its own inherent uncertainties.

For passive pipe break failures rates have been given an uncertainty parameter as presented in Section 8.5. The impact of these uncertainties can be treated by the use of a random sampling Monte Carlo process as discussed in Section 10.1.

Human induced flooding events present another difficult challenge. The use of the HRA Calculator program from Scientech creates an assumed uncertainty term for any HRA action. Since the human induced flooding events is a combination of both pre-initiating event and post initiating event, each portion has an independent uncertainty term. The HRA

Calculation program also arbitrarily assigns an uncertainty term to HRA actions based on the calculated probabilities, see the HRA Calculation for more information on the uncertainty parameters (Reference 68). The other fundamental issue that is presented in human induced flooding events is the location of work. Depending on where the actual work is being performed in a flood area, isolation could be a concern as the next available valve could be in an inaccessible area. Additionally, there are no detailed procedures to address having a flood occur during a maintenance event.

Maintenance induced flooding events also present a level of uncertainty. The three main inputs to the calculation of this frequency, failure rate of an MOV, mission time, and frequency of the activity all introduce some level of uncertainty into the calculation. The large internal rupture of an MOV is assumed in NUREG/CR-6928 to be a factor of 0.02 less than that of a small internal leak on an MOV (Reference 104), as there has been no actual large internal rupture events in the industry. The mission time is also assumed based on a seven day repair interval, this number could potentially be greater than that if the component is not covered by an Technical Specification or, more likely, less than the assumed seven day repair time. The final area of uncertainty is the frequency of the activity. Most of the procedures reviewed in Appendix J have frequencies as well as conditions. These conditions could cause the actual maintenance activity to occur more times than the frequency noted in the procedure.

Finding 4-11

Summary:

While the PRA model considers the possibility of two PORVs being blocked at the same time, there does not appear to have been an investigation of whether coincident maintenance can occur in the various SQN systems (or if coincident intersystem maintenance can occur). Therefore this SR is not met.

It was also observed that the PORV blocking basis events noted above did not appear to be documented in either the data notebook or the appropriate system notebook.

Resolution:

The following was added to the data analysis notebook to address coincident maintenance:

Coincident maintenance is scheduling maintenance where multiple SSCs are out of service at the same time. Specifically components on the same train, RHR train A and SI train A for example, being out of service for maintenance at the same time. The Outage and Site Scheduling Directive Manual 1.0 (Reference 28) dictates that:

Twelve (12) week schedule by FEG groups ensures that within a train week, no two (2) accident mitigating devices are removed from service at the same time [i.e., "A" train residual Heat Removal (RHR) is not removed from service at the same time as "A" train Containment Spray.]

This requirement is further discussed in the Outage and Site Scheduling Directive Manual 4.7 (Reference 29) which states that any systems important to PRA that are unavailable at the same time must meet the requires of the plant risk matrix. Normally maintenance on any systems important to the PRA is not scheduled at the same time. If it is these instances are extremely rare and the current model does not exclude coincident maintenance events from appearing in a single cutset. Therefore the probability of having coincident maintenance events is extremely rare and accounted for during the normal cutset processing.

Finding 5-2

Summary:

Some HFEs are set to a value of 0.0 for quantification. For example, HACI1 and HAAE1 are recovery actions for automatic signals ANDed with the signal logic. However, the HRA analysis sets the HEP probability to 0.0 based on an analysis that the operator action is not required. This screening approach, combined with the model structure, removes the auto actuation contribution to mitigating system failure during quantification.

Resolution:

For those events where 0.0s were used in the model the fault tree was updated to remove the events so that the conflict concerning an AND gate and a zero event will no longer be encountered during normal quantification.

Finding 6-2

Summary:

The justification for excluding plant data prior to July 2002 in the calculation of plant specific IE frequencies is not documented well enough to support IE-C2.

Resolution:

Added discussion to notebook stating that date range was adequate to get a good sample of plant data without going too far back and including events that occurred when the plant may have had different procedures and operating practices.

Finding 6-3

Summary:

The alignment flags in the ERCW system are not fully implemented to represent the system alignment within the Initiating event portion of the tree. For example, the gates under U0_AEX_G006 should contain flags to indicate which pump is running and which two pumps are not, so that the two non-running pumps would have considerations for failures to start.

Resolution:

The current flag alignment for ERCW has been revised so, for the baseline model, without setting a specific configuration, the flag files were set to the respective time in each configuration to that a probability is now used not a true or false value.

Finding 6-5

Summary:

The support system initiating event trees for the most part include provisions for common cause failures and routine system alignments. There are some discrepancies in the modeling of common cause failures in the ERCW and CCS models that require attention, however. For example:

1) While a common cause event for all 3 of the 1A, 1B, and C-S pumps failing to run exists, there are not events for the 1A and C-S pumps or the 1B and C-S pumps.

2) The structure of the ERCW tree is such that pump common cause failures could result in a pump failing due to an independent failure as well as a common cause failure in a single cutset. (See gate U0_AEX_G001)

3) The common cause initiating event group U0_ERW08POEFRI is not valid, since it is entirely based on 8760 hour exposure time for all the components. The common cause failure frequencies are therefore overestimated. The CCS tree uses a different approach than the ERCW tree for common cause initiating events. An alternate approach is also given in EPRI reports 1013490 and 1016741.

Resolution:

With respect to the common cause failure of the CCS pumps:

The common cause failure of the 1A and the C-S pump or the 1B and the C-S pump would not meet the requirements to cause an initiating event for the CCS system. Only failure of the A train would cause the plant to have to trip as the loads on the common train are not required for operation at power. Therefore only the common cause failure of all three pumps is modeled in the fault tree.

With respect to the common cause failure events from the ERCW fault tree:

The common cause failure events in the ERCW system where common cause failure and independent failures show up in the same cutset present a minimal and conservative impact.

With respect the common cause calculation of basic events:

The common cause failure rates for ERCW pumps failing to run and CCS pumps failing to run were revised based on the EPRI document 1013490 using the discussion presented on page 5-8. The assumptions and calculation of these basic events is noted in Appendix B of each calculation.

Finding 6-6

Summary:

Section 5 of the IE notebook shows a Bayesian process was used to combine plant specific and generic data. However, LOCA frequencies from NUREG-1829 were also updated with plant specific data. Since the frequencies in NUREG-1829 were based on expert judgment and not actual industry data, and it is not expected that a plant would experience such an event, it does not seem appropriate to use the Bayesian update process for these events. The update did not appear to significantly alter the IE frequencies, however, so there is little impact on CDF.

Resolution:

The frequencies presented in NUREG-1829 represent the best estimates available at that time. There is no restriction on updating an expert solicitation, as the update process will only serve as to better estimate the actual failure rate for the initialing events.

Finding 6-7

Summary:

Section 6 of the Initiating Events Analysis, the associated system notebooks, and the HRA notebook document the use of plant-specific information in the assessment and quantification of recovery actions where available, in a manner consistent with the applicable HR SRs.

An issue was noted with the ERCW initiating event tree. Event HAAEIE "Operator Fails to Start ERCW Pump (Initiating Event)" has been set to zero based on an analysis that found one pump was sufficient to cool plant loads, so if one of the two running pumps trips, operator action is not required to start another pump. Operator action to start a standby pump would be required, however, if flow was to be lost from both running pumps. The current model essentially assumes a successful operator action to start both of those pumps.

Resolution:

The ERCW initiating event model has been updated.

Calculation CN-NUC-SQN-MEB-MDQ-000-067-2000-0095 revised the existing success criteria used in the initiating event model. The results of the calculation indicate that as long as the containment spray heat exchangers were not in service, the maximum required flow on the ERCW system would be roughly 9,000 gallons. This is within the design flow rate of 10,000 gallons per minute from one ERCW pump. Due to the change in the success criteria, the initiating event model was update to requiring the failure of two running ERCW pumps as well as failure of both standby ERCW pumps to start.

The HRA action HAAEIE was added to the model under the appropriate failure to start gate, no longer under an AND gate.

Additionally, the fault tree logic in question was update so that failure to start takes into account the failure of operation action HAAEIE.

Finding 6-10

Summary:

Tables 42 and 43 of MDN-000-000-2010-0209 contain a list of modeling assumptions and their impact on the PRA model. However, the majority of items in Table 43 have an impact of "Unknown." Classification of model impact for these assumptions is necessary to meet this SR.

Resolution:

The Uncertainty and Sensitivity Analysis calculation has been updated in the following ways:

Text concerning the discussion of Unknown impacts and performing a respective uncertainty analysis was removed from Section 5.0.

Table 43 was updated to remove the column "Model Impact" and the column "Comments" was updated to "Model Impacts and Comments" and expanded.

Finding 6-12

Summary:

From the results presented in sections 5.2 and 5.7 of MDN 000 000 2010 0208, it can be inferred that the definition of significant basic event and significant accident sequence are consistent with those listed in Part 2 of the standard. This is not explicitly stated in the documentation, however. The definition of significant cutset is not provided, nor does the 100 cutset list provided in the documentation imply that the part 2 definition was used, as the 100 cutsets do not represent 95% of the risk.

Resolution:

The documented definition in Section 1 2.2 of the ASME/ANS combined standard was added to the quantification calculation.

E.1.4.8 PRA Maintenance and Update

The TVA PRA process ensures that the PRA models adequately reflect the as-built and as-operated plant configurations. This process is defined in TVA procedures NPG-SPP-09.11, "Probabilistic Risk Assessment (PRA) Program," and NEDP-26, "Probabilistic Risk Assessment." The PRA Program procedure delineates the responsibilities of both corporate and site personnel and provides guidelines for the initiation of, and the data collection for PRA model updates. The PRA Procedure implements the PRA Program requirements by elaborating on responsibilities, establishing the technical qualifications for PRA personnel (analysts), and providing specific guidance on the PRA update. Overall, they define the process for implementing regularly scheduled and interim PRA model updates, for tracking issues identified as potentially affecting the PRA models (e.g., due to changes in the plant, errors or limitations identified in the model, industry operational experience), and for controlling the model and associated computer files. Various information sources are monitored on an ongoing basis to identify changes or new information that will affect the model, model assumptions, or quantification. Information sources include:

- Plant modifications,
- Operating experience,
- Technical Specification changes,
- Maintenance Rule changes,
- Engineering calculation revisions,
- Procedure changes, and
- Industry studies.

PRA updates are generally completed at least once every other fuel cycle (for the lead unit at multi-unit sites) or sooner if estimated cumulative impact of plant configuration changes exceed the threshold of +/- 10% of CDF or LERF. Changes in PRA inputs or discovery of new information are evaluated to determine whether such information warrants a PRA update. Items exceeding the above threshold are tracked in the Corrective Action Program. Potential and/or implemented plant configuration changes that do not meet the threshold for immediate update are tracked in the PRA Model Open Items Database.

The PRA Procedure includes requirements for a review of PRA model updates. Individual work products (such as, a system notebook) are reviewed and checked by a second qualified PRA analyst after preparation. That is followed by review and approval by the PRA supervisor. Following completion of the update, a review is performed by a technically qualified individual that reviews changes to the model to ensure that the intent and execution of the change were both accurate and complete. Items specifically included in the review are the affected fault trees, updated data, event trees, revised system notebooks, top 100 core damage sequences/cutsets, top 10 detailed core damage sequence/cutset descriptions and importance calculations. A comparison of updated results to the previous model is also performed in order to identify unexpected changes which must be addressed and resolved.

Requirements for PRA documentation and control of model files are also addressed in the PRA Procedure. PRA models are required to be documented in a manner that facilitates peer review as well as future updates and applications by describing the processes that were used and providing details of the assumptions made and their bases. The PRA Model of Record (MOR) is composed of the 1) PRA computer model and supporting documentation, 2) Modular Accident Analysis Program (MAAP) model and supporting documentation, and 3) any other supporting computer evaluations. The PRA MOR is stored as read-only on a specified network server with a master copy placed on a read only CD-R and copies retained by the site(s) and corporate PRA Staff.

E.1.5 The WinMACCS Model – Level 3 Analysis

E.1.5.1 Introduction

SAMA evaluation relies on Level 3 PRA results to measure the effects of potential plant modifications. A Level 3 PRA model using Version 3.6.0 of Windows interface for MACCS2, MELCOR Accident Consequence Code (WinMACCS) was created for SQN. This model which requires detailed site-specific meteorological, population, and economic data, estimates the consequences in terms of population dose and offsite economic cost. Risks in terms of population dose risk (PDR) and offsite economic cost risk (OECR) were also estimated in this analysis. Risk is defined as the product of consequence and frequency of an accidental release.

This analysis considers a base case and two sensitivity cases to account for variations in data and assumptions for postulated internal events. The base case uses estimated speed and population fraction for evacuation. Sensitivity case 1 is the base case with higher and lower evacuation speeds. Sensitivity case 2 is the base case with smaller and larger fractions of the population that evacuate.

PDR was estimated by summing over all releases the product of population dose and frequency for each accidental release. Similarly, OECR was estimated by summing over all releases the product of offsite economic cost and frequency for each accidental release. Offsite economic cost includes costs that could be incurred during the emergency response phase and costs that could be incurred through long-term protective actions.

E.1.5.2 Input

The following sections describe the site-specific input parameters used to obtain the off-site dose and economic impacts for cost-benefit analyses.

E.1.5.2.1 Projected Total Population by Spatial Element

The total population within a 50-mile radius of SQN was estimated for the year 2041 including transient population. Areal weighting was used to transfer the 2041 projected total population from source areas (county) to target areas (spatial elements) using SECPOP2000 version 3.13.1. Tennessee, North Carolina, Alabama, and Georgia state tourism data was used to calculate a transient population to increase permanent population to account for transient populations. Total projected population of the 50-mi zone of analysis is 1,537,408, and the distribution of the 2041 total population is summarized in Table E.1-18.

Table E.1-18 - Estimated Population Distribution within a 50-Mile Radius

Direction	0 to 10 Miles	11 to 20 Miles	21 to 30 Miles	31 to 40 Miles	41 to 50 Miles	Total
N	3,674	10,760	5,305	6,188	28,425	54,352
NNE	1,156	12,200	10,908	12,871	15,776	52,911
NE	2,975	4,672	9,844	11,761	25,876	55,128
ENE	2,290	7,756	14,687	44,628	29,841	99,202
E	4,117	39,238	10,640	5,293	6,544	65,832
ESE	4,386	66,734	7,740	1,886	24,228	104,974
SE	3,871	9,759	11,793	5,974	15,482	46,879
SSE	6,634	13,341	31,004	83,296	18,154	152,429
S	13,034	52,280	43,407	35,950	22,566	167,237
SSW	15,433	128,791	59,809	27,398	17,774	249,205
SW	13,629	129,629	42,543	19,124	13,594	218,519
WSW	29,000	53,021	7,940	22,131	13,628	125,720
W	14,406	5,338	11,446	8,050	12,882	52,122
WNW	6,887	4,919	7,022	8,123	5,447	32,398
NW	6,253	2,513	3,866	2,012	20,243	34,887
NNW	4,110	1,711	5,950	5,601	8,241	25,613
Totals	**131,855**	**542,662**	**283,904**	**300,286**	**278,701**	**1,537,408**

E.1.5.2.2 Land Fraction

The land fractions are populated by SECPOP2000. SECPOP2000 uses county-level databases which contain the land-fraction data for every county in the continental U.S. A value of 1.00 indicates the spatial element area is all land, with no significant surface water.

E.1.5.2.3 Watershed Class

Watershed Index is defined by WinMACCS as areas drained by rivers (Class 1) or large water bodies (Class 2). Class 2 is intended only for use with a very large lake, similar in size to Lake Michigan. For SQN, a watershed index of 1 (drained by rivers) was used for all spatial elements.

E.1.5.2.4 Region Index

SECPOP2000 defines each region in the spatial grid as a given number between 1 and 97. These values are then given an economic index. However, this economic data is based on 2002 economic data and would not be an accurate representation in 2041. Therefore, an economic multiplier was determined based on past data to determine the dollar value in 2041. In order to estimate the dollar value in 2041, the consumer price index (CPI) from 1970 through 2010 was plotted. A trend line was added to this plot to determine the slope of the line. This line was then extrapolated through 2041 to determine the CPI in 2041. The economic multiplier is calculated to be 2.0329 for 2041 when compared with 2002 dollar values.

E.1.5.2.5 Agricultural Data

The regional crop information is the 2007 United States Census of Agriculture. This data was analyzed and compared with the generic data created from SECPOP2000. The generic data was determined to be more conservative and was used to represent regional crop data surrounding the SQN site.

E.1.5.2.6 Meteorological Data

The WinMACCS model requires meteorological data for wind speed, wind direction, atmospheric stability, accumulated precipitation, and atmospheric mixing heights. The required data was obtained from the SQN meteorological monitoring system and the US Environmental Protection Agency.

Site-Specific Data

Meteorological data collected at the site from calendar years 2003 through 2005 were compiled for the WinMACCS input file. Missing data for parameters of interest were estimated using data substitution methods. When only one hour of data was missing, values were interpolated based on the values immediately before and after the data gap. When more than one hour of data was missing in series, then the data was replaced with data from days with similar meteorological conditions immediately before and after the missing data. The 2005 data resulted in the highest release quantities and was therefore used to perform the base case analysis and sensitivity cases.

Regional Mixing Height Data

Mixing height is defined as the height of the atmosphere above ground level within which a released contaminant will become mixed (from turbulence) within approximately one hour. SQN mixing height data were estimated using the SCRAM Mixing Height Data from the US Environmental Protection Agency.

E.1.5.2.7 Emergency Response Assumptions

A detailed analysis of evacuation scenarios in the 10-mile emergency planning zone (EPZ) were addressed in the Tennessee Multi-Jurisdictional Radiological Emergency Response Plan for the Sequoyah Nuclear Plant.

Evacuation Delay Time

The Tennessee Multi-Jurisdictional Radiological Emergency Response Plan for the Sequoyah Nuclear Plant estimated that the maximum preparation time for evacuation to begin of all people within the EPZ would be 105 minutes. This includes 75 minutes for notification and 30 minutes for preparation, for a total delay of 105 minutes.

Evacuation Speed

The Tennessee Multi-Jurisdictional Radiological Emergency Response Plan for the Sequoyah Nuclear Plant estimated that the travel speeds on major evacuation routes would be 20 mph. Conservatively, a 5 mph (2.2 m/s) evacuation speed was used for the base case since many drivers may choose to take local roads with lower capacities and therefore, lower speeds.

E.1.5.2.8 Core Inventory

The SQN Unit 1 core inventory is shown in Table E.1-19. The core inventory for Unit 1 was used for both Unit 1 and Unit 2. This is conservative since the plants are very similar in design and Unit 1 has a slightly higher power output (1148 MWe for Unit 1 vs 1126 MWe for Unit 2). The core inventory was taken from Watts Bar Unit 1, and multiplied by the ratio of power output from SQN Unit 1 to the power output of Watts Bar Unit 1 (1123 MWe). Since these plants are very similar in design, the core inventory was assumed to be similar.

Table E.1-19 - SQN Unit 1 Core Inventory

Nuclide	Isotope	Inventory (Bq)	Nuclide	Isotope	Inventory (Bq)
Krypton	Kr-83m	4.35E+17	*Molybdenum*	Mo-99	6.73E+18
	Kr-85	3.90E+16	*Rhodium*	Rh-103m	5.60E+18
	Kr-85m	9.04E+17		Rh-105	3.61E+18
	Kr-87	1.82E+18		Rh-106	2.02E+18
	Kr-88	2.52E+18	*Ruthenium*	Ru-103	5.60E+18
Xenon	Xe-133	7.22E+18		Ru-105	3.78E+18
	Xe-135	2.43E+18		Ru-106	1.89E+18
	Xe-135m	1.53E+18	*Technetium*	Tc-101	6.09E+18
	Xe-138	6.32E+18		Tc-99m	5.94E+18
Cesium	Cs-134	6.28E+17	*Strontium*	Sr-89	3.53E+18
	Cs-136	2.23E+17		Sr-90	3.38E+17
	Cs-137	4.43E+17		Sr-91	4.39E+18
	Cs-138	6.85E+18		Sr-92	4.69E+18
Rubidium	Rb-86	7.07E+15	*Cerium*	Ce-141	6.01E+18
	Rb-88	2.58E+18		Ce-143	5.60E+18
	Rb-89	3.37E+18		Ce-144	4.88E+18
Barium	Ba-137m	4.20E+17	*Neptunium*	Np-239	7.07E+19
	Ba-139	6.54E+18	*Plutonium*	Pu-238	1.19E+16
	Ba-140	6.54E+18		Pu-239	1.32E+15
	Ba-141	5.90E+18		Pu-240	1.66E+15
	Ba-142	5.64E+18		Pu-241	5.64E+17
Bromine	Br-83	4.35E+17	*Americium*	Am-241	3.71E+14
	Br-84	8.09E+17	*Curium*	Cm-242	1.51E+17
Iodine	I-130	7.30E+16		Cm-244	6.09E+15
	I-131	3.58E+18	*Lanthanum*	La-140	6.77E+18
	I-132	5.26E+18		La-141	5.98E+18
	I-133	7.38E+18		La-142	5.82E+18

Nuclide	Isotope	Inventory (Bq)	Nuclide	Isotope	Inventory (Bq)
	I-134	8.17E+18		La-143	5.52E+18
	I-135	7.04E+18	*Niobium*	Nb-95	6.39E+18
Antimony	Sb-127	3.05E+17		Nb-97	6.13E+18
	Sb-129	1.15E+18		Nb-97m	5.79E+18
	Sb-130	3.78E+17	*Neodymium*	Nd-147	2.42E+18
Tellurium	Te-125m	7.30E+14	*Praseodymium*	Pr-143	5.45E+18
	Te-127	3.00E+17		Pr-144	4.92E+18
	Te-127m	5.03E+16		Pr-145	3.82E+18
	Te-129	1.09E+18	*Yttrium*	Y-90	3.59E+17
	Te-129m	2.20E+17		Y-91	4.58E+18
	Te-131	3.02E+18		Y-91m	2.56E+18
	Te-131m	7.04E+17		Y-92	4.73E+18
	Te-132	5.14E+18		Y-93	3.59E+18
	Te-133	4.01E+18		Y-94	5.71E+18
	Te-134	6.54E+18		Y-95	5.94E+18
Cobalt	Co-58	4.20E+16	*Zirconium*	Zr-95	6.32E+18
	Co-60	3.28E+16		Zr-97	6.09E+18

E.1.5.2.9 Source Terms

Twelve release categories were part of the WinMACCS input. Section E.1.2.3 provides details of the source terms for each release category. A linear release rate was assumed between the time the release started and the time the release ended.

E.1.5.3 Results

Risk estimates for one base case and two sensitivity cases were analyzed with WinMACCS. Sensitivity case one evaluates slower (1.6 m/s) and faster (3.4 m/s) evacuation speeds. Sensitivity case two evaluates a lower (90%) and higher (99.5%) evacuating fraction of the public.

Table E.1-20 and Table E.1-21 shows the base case mean risk values for each release mode for SQN Unit 1 and Unit 2, respectively. The estimated mean values of population dose risk and offsite economic cost risk for SQN Unit 1 are 45 person-rem/yr and $97,000/yr, respectively. The estimated mean values of population dose risk and offsite economic cost risk for SQN Unit 2 are 43.9 person-rem/yr and $93,100/yr, respectively.

Table E.1-20 - SQN Unit 1 Base Case Results

Characteristics of Release Mode		Population Dose	Offsite Economic Cost	Population Dose Risk	Offsite Economic Cost Risk
Release Category	yr^{-1}	person-rem	$	person-rem/yr	$/yr
SQN Ia	4.057E-08	2.85E+06	5.74E+09	1.16E-01	2.33E+02
SQN Ib	9.7E-07	2.57E+06	5.32E+09	2.49E+00	5.16E+03
SQN Ic	2.653E-07	2.62E+06	5.41E+09	6.95E-01	1.44E+03
SQN IIa	3.263E-06	3.63E+06	6.75E+09	1.18E+01	2.20E+04
SQN IIb	6.293E-07	3.42E+06	6.61E+09	2.15E+00	4.16E+03
SQN IIc	6.473E-08	1.93E+06	4.50E+09	1.25E-01	2.91E+02
SQN IId	4.774E-08	2.20E+06	5.05E+09	1.05E-01	2.41E+02
SQN III	6.431E-07	9.09E+06	1.09E+10	5.85E+00	7.01E+03
SQN IVa	1.792E-05	1.06E+06	2.81E+09	1.90E+01	5.04E+04
SQN IVb	2.226E-06	9.88E+05	2.56E+09	2.20E+00	5.70E+03
SQN Va	2.078E-06	1.35E+05	1.24E+08	2.81E-01	2.58E+02
SQN Vb	1.133E-06	1.29E+05	1.18E+08	1.46E-01	1.34E+02
			Totals	**4.50E+01**	**9.70E+04**

Table E.1-21 - SQN Unit 2 Base Case Results

Characteristics of Release Mode		Population Dose	Offsite Economic Cost	Population Dose Risk	Offsite Economic Cost Risk
Release Category	yr^{-1}	person-rem	$	person-rem/yr	$/yr
SQN Ia	4.55E-08	2.85E+06	5.74E+09	1.30E-01	2.61E+02
SQN Ib	9.527E-07	2.57E+06	5.32E+09	2.45E+00	5.07E+03
SQN Ic	3.86E-07	2.62E+06	5.41E+09	1.01E+00	2.09E+03
SQN IIa	3.302E-06	3.63E+06	6.75E+09	1.20E+01	2.23E+04
SQN IIb	3.255E-07	3.42E+06	6.61E+09	1.11E+00	2.15E+03
SQN IIc	6.263E-08	1.93E+06	4.50E+09	1.21E-01	2.82E+02
SQN IId	6.757E-08	2.20E+06	5.05E+09	1.49E-01	3.41E+02
SQN III	7.409E-07	9.09E+06	1.09E+10	6.73E+00	8.08E+03
SQN IVa	1.741E-05	1.06E+06	2.81E+09	1.85E+01	4.89E+04
SQN IVb	1.239E-06	9.88E+05	2.56E+09	1.22E+00	3.17E+03
SQN Va	2.007E-06	1.35E+05	1.24E+08	2.71E-01	2.49E+02
SQN Vb	1.924E-06	1.29E+05	1.18E+08	2.48E-01	2.27E+02
			Totals	**4.39E+01**	**9.31E+04**

The results of the evacuation speed sensitivity showed a slight increase in population dose risk with slower evacuation speeds and a slight decrease in population dose risk with faster evacuation speeds as shown in Table E.1-22.

Table E.1-22 - Evacuation Speed Sensitivity

Evacuation Speed	**Unit 1 Dose Risk**	**Unit 2 Dose Risk**
(m/s)	(Person-Rem/RY)	(Person-Rem/RY)
1.6	4.76E+01	4.65E+01
2.2	4.50E+01	4.39E+01
3.4	4.46E+01	4.34E+01

The results of the evacuation fraction sensitivity showed a slight increase in population dose risk with a lower evacuation fraction and a slight decrease in population dose risk with a higher evacuation fraction as shown in Table E.1-23.

Table E.1-23 – Evacuation Fraction Sensitivity

Evacuating Fraction	**Unit 1 Dose Risk**	**Unit 2 Dose Risk**
%	(Person-Rem/RY)	(Person-Rem/RY)
90	4.58E+01	4.47E+01
95	4.50E+01	4.39E+01
99.5	4.35E+01	4.23E+01

E.1.5.4 Baseline Risk Monetization

E.1.5.4.1 Off-Site Exposure Cost

The annual off-site exposure risk was converted to dollars using the conversion factor of $2,000 per person-rem, and discounted to present value using the following standard formula:

Where:
W_{PHA} is the monetary value of off-site exposure cost after discounting ($/yr);
R is the monetary equivalent of dose ($2,000 per person-rem);
D_{PA} is the avoided public dose (person-rem/yr);
r is the real discount rate (7%) with a sensitivity performed at 3%; and
t_f is the years remaining until end of facility life (20 years).

Using the avoided public dose (D_{PA}) from Table E.1-20 and Table E.1-21, and the two discounting factors, W_{PHA} is calculated in Table E.1-24 for Unit 1 and Unit 2.

Table E.1-24 – Off-Site Exposure Cost for Unit 1 and Unit 2

	Unit 1		**Unit 2**	
D_{PA} (person-rem/yr)	4.50E+01		4.39E+01	
R ($/person-rem)	2000		2000	
t_f (yr)	20		20	
r (%)	0.07	0.03	0.07	0.03
W_{PHA} ($/yr)	968,661	1,353,565	944,983	1,320,478

E.1.5.4.2 Off-Site Economic Cost

The annual off-site economic risk was calculated and discounted to present value using the following standard formula:

Where:
W_{EA} is the monetary value of economic risk after discounting ($/yr);
Z_{EA} is the monetary value of economic (accident) risk per year before discounting ($/yr);
r is the real discount rate (7%) with a sensitivity performed at 3%; and
t_f is the years remaining until end of facility life (20 years).

Using the monetary value of economic (accident) risk per year before discounting (Z_{EA}) from Table E.1-20 and Table E.1-21, and the two discounting factors, W_{EA} is calculated in Table E.1-25 for Unit 1 and Unit 2.

Table E.1-25 – Off-Site Economic Cost for Unit 1 and Unit 2

	Unit 1		**Unit 2**	
Z_{EA} ($/yr)	9.70E+04		9.31E+04	
t_f (yr)	20		20	
r (%)	0.07	0.03	0.07	0.03
W_{EA} ($/yr)	1,044,001	1,458,842	1,002,026	1,400,188

E.1.5.4.3 On-Site Exposure Cost

The values for on-site (occupational) exposure consist of "immediate dose" and "long-term dose." The best estimate value provided in NUREG/BR-0184 (Ref. E.1-11) for immediate occupational dose is 3,300 person-rem per event and long-term occupational dose is 20,000 person-rem (over a ten year clean-up period). The following equation is used to calculate "immediate dose" on-site exposure cost:

Where:
W_{IO} is the immediate monetary value of on-site exposure after discounting ($/yr);
D_{IO} is immediate occupational dose (3,300 person-rem per event);
CDF is the core damage frequency;
R is the monetary equivalent of dose ($2,000 per person-rem);
r is the real discount rate (7%) with a sensitivity performed at 3%; and
t_f is the years remaining until end of facility life (20 years).

Table E.1-26 provides the results for the immediate monetary cost of on-site exposure for Unit 1 and Unit 2.

Table E.1-26 – Immediate On-Site Exposure Cost for Unit 1 and Unit 2

	Unit 1		**Unit 2**	
CDF(events/yr)	2.960E-05		3.509E-05	
D_{IO} (person-rem/event)	3300		3300	
R ($/person-rem)	2000		2000	
t_f (yr)	20		20	
r (%)	0.07	0.03	0.07	0.03
W_{IO} ($/yr)	2,103	2,938	2,493	3,483

The following equation is used to calculate "long-term dose" on-site exposure cost:

Where:
W_{LTO} is the long-term monetary value of on-site exposure after discounting ($);
D_{LTO} is the long-term occupational dose (20,000 person-rem per event);
CDF is the core damage frequency;
R is the monetary equivalent of dose ($2,000 per person-rem);
m is the number of years over which the long-term dose occurs (10 years);
r is the real discount rate (7%) with a sensitivity performed at 3%; and
t_f is the years remaining until end of facility life (20 years).

Table E.1-27 provides the results for the long-term monetary cost of on-site exposure for Unit 1 and Unit 2.

Table E.1-27 – Long-Term On-Site Exposure Cost for Unit 1 and Unit 2

	Unit 1		Unit 2	
CDF (events/yr)	2.960E-05		3.509E-05	
D_{LTO} (person-rem/event)	20000		20000	
R ($/person-rem)	2000		2000	
t_f (yr)	20		20	
m (years)	10		10	
r (%)	0.07	0.03	0.07	0.03
W_{LTO} ($/yr)	9,165	15,384	10,864	18,237

The on-site exposure cost (W_O) is the sum of the immediate monetary value of on-site exposure after discounting (W_{IO}) and the long-term monetary value of on-site exposure after discounting (W_{LTO}). On-site exposure cost (W_O) is calculated in Table E.1-28 for Unit 1 and Unit 2.

Table E.1-28 – On-Site Exposure Cost for Unit 1 and Unit 2

	Unit 1		Unit 2	
r (%)	0.07	0.03	0.07	0.03
W_{IO} ($/yr)	2,103	2,938	2,493	3,483
W_{LTO} ($/yr)	9,165	15,384	10,864	18,237
W_O ($/yr)	11,267	18,322	13,357	21,720

E.1.5.4.4 On-Site Cleanup Cost

The on-site cleanup cost is the estimated cost for cleanup and decontamination of the site. The total undiscounted cost of cleanup and decontamination for a single accident in constant year dollars is $1,500,000,000 (Ref. E.1-11). The following equation is used to calculate the on-site cleanup cost:

Where:
W_{CD} is the on-site cleanup cost ($/yr);
CDF is the core damage frequency;
C_{CD} is the total undiscounted cost of cleanup and decontamination in constant year dollars ($1,500,000,000);
m is the number of years over which cleanup occurs (10 years);
r is the real discount rate (7%) with a sensitivity performed at 3%; and
t_f is the years remaining until end of facility life (20 years).

Using the core damage frequency (CDF) and the two discounting factors, on-site cleanup cost (W_{CD}) is calculated in Table E.1-29 Unit 1 and Unit 2.

Table E.1-29 – On-Site Cleanup Cost for Unit 1 and Unit 2

	Unit 1		Unit 2	
CDF (events/yr)	2.960E-05		3.509E-05	
C_{CD} (\$)	1,500,000,000		1,500,000,000	
t_f (yr)	20		20	
m (years)	10		10	
r (%)	0.07	0.03	0.07	0.03
W_{CD} (\$/yr)	343,669	576,903	407,410	683,903

E.1.5.4.5 Replacement Power Cost

Long-term replacement power costs were determined following the methodology in NUREG/BR-0184 (Ref. E.1-11). Determining replacement power cost requires calculating the net present value of replacement power for a single event (PV_{RP}). The equation for PV_{RP} can be found is shown below:

Where:
PV_{RP} is the net present value of replacement power for a single event (\$);
φ is a constant representing a string of replacement power costs that occur over the lifetime of a reactor after an event (for a 910 MWe "generic" reactor, NUREG/BR-0184 uses a value of \$120,000,000/yr;
$P_{SQN(1)}$ is the power output of Sequoyah Unit 1 (1148 MWe);
$P_{SQN(2)}$ is the power output of Sequoyah Unit 2 (1126 MWe);
P_{GEN} is the power output of the "generic" reactor used in NUREG/BR-0184 (910 MWe);
r is the real discount rate (7%); and
t_f is the years remaining until end of facility life (20 years).

For a 3% sensitivity discount rate, NUREG/BR-0184 states that PV_{RP} is \$1,400,000,000. Table E.1-30 provides the values for net present value of replacement power for a single event.

Table E.1-30 – Net Present Value Replacement Power for Unit 1 and Unit 2

	Unit 1		Unit 2	
φ (\$)	\$120,000,000		\$120,000,000	
PSQN (MWe)	1,148		1,126	
PGEN (MWe)	910		910	
t_f (yr)	20		20	
r (%)	0.07	0.03	0.07	0.03
PV_{RP} (\$)	1,227,547,861	1,400,000,000	1,204,023,424	1,400,000,000

Long-term replacement power costs can then be determined using the following equation:

Where:
W_{RP} is the long-term replacement power cost (\$/yr);

CDF is the core damage frequency;
PV_{RP} is the net present value of replacement power for a single event ($);
r is the real discount rate (7%) with a sensitivity performed at 3%; and
t_f is the years remaining until end of facility life (20 years).

Using the core damage frequency (CDF), the calculated values for PV_{RP} as calculated above, and the two discounting factors, long-term replacement power cost (W_{RP}) is calculated in Table E.1-31 for Unit 1 and Unit 2.

Table E.1-31 – Long-Term Replacement Power Cost for Unit 1 and Unit 2

	Unit 1		Unit 2	
CDF (events/yr)	2.960E-05		3.509E-05	
t_f (yr)	20		20	
PV_{RP} ($)	1,227,547,861	1,400,000,000	1,204,023,424	1,400,000,000
r (%)	0.07	0.03	0.07	0.03
W_{RP} ($/yr)	294,637	281,199	342,590	333,354

E.1.5.4.6 Total Cost of Severe Accident Risk / Maximum Benefit

The sum of the baseline costs is shown in Table E.1-32 for Unit 1 and Unit 2.

Table E.1-32 – Maximum Averted Cost Risk for Unit 1 and Unit 2

	Unit 1		Unit 2	
Cost	7% Real Discount Rate	3% Discount Rate Sensitivity	7% Real Discount Rate	3% Discount Rate Sensitivity
Off-Site Exposure Cost (W_{PHA}) ($/yr)	968,661	1,353,565	944,983	1,320,478
Off-Site Economic Cost (W_{EA}) ($/yr)	1,044,001	1,458,842	1,002,026	1,400,188
On-Site Exposure Cost (W_O) ($/yr)	11,267	18,322	13,357	21,720
On-Site Cleanup Cost (W_{CD}) ($/yr)	343,669	576,903	407,410	683,903
Replacement Power Cost (W_{RP}) ($/yr)	294,637	281,199	342,590	333,354
Maximum Averted Cost Risk (MACR) ($/yr)	2,662,235	3,688,832	2,710,366	3,759,643
External Event Multiplier	2.9	2.9	2.6	2.6
Modified MACR (MMACR) ($/yr)	7,720,482	10,697,613	7,046,951	9,775,073

The MACR, $2,662,235 for Unit 1 and $2,710,366 for Unit 2 is based on at-power internal event contributions.

The internal event MACR is multiplied by a factor of 2.9 for Unit 1 and 2.6 for Unit 2 to account for external event contributions. The resulting modified MACR (MMACR) is $7,720,482 for Unit 1 and $7,046,951 for Unit 2. These values will be used in the Severe Accident Mitigation Analysis (SAMA) screening process.

E.1.6 References

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E.1-11 NUREG/BR-0184, "Regulatory Analysis Technical Evaluation Handbook," January 1997.

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ATTACHMENT E.2
EVALUATION OF SAMA CANDIDATES

E.2 EVALUATION OF SQN SAMA CANDIDATES

E.2.1 SAMA List Compilation

A list of SAMA candidates was developed by reviewing industry documents, and considering other plant-specific enhancements not identified in the published industry documents. Since SQN is an ice-condenser plant, considerable attention was paid to the SAMA candidates from SAMA analyses for other ice condenser plants. Industry documents reviewed included the following:

1. NEI 05-01, Severe Accident Mitigation Alternatives (SAMA) Analysis Guidance Document (NEI 2005);
2. NRC and industry documentation discussing potential plant improvements
    - Watts Bar Unit 2 Nuclear Plant SAMA Analysis (Ref. E.2-2)
    - Columbia Generating Station SAMA Analysis (Ref. E.2-3)
    - Cooper Nuclear Station SAMA Analysis (Ref. E.2-4)
    - Kewaunee Power Station SAMA Analysis (Ref. E.2-5)
    - Vogtle Electric Generation Plant SAMA Analysis (Ref. E.2-6)
    - Wolf Creek Generating Station SAMA Analysis (Ref. E.2-7)
    - D.C. Cook Nuclear Plant SAMA Analysis (Ref. E.2-8)
    - Catawba Nuclear Station (Ref. E.2-9)
    - McGuire Nuclear Station SAMA Analysis (Ref. E.2-10)
    - Palo Verde Nuclear Generating Station (Ref. E.2-14)
    - Crystal River Unit 3 Nuclear Generating Station (Ref. E.2-15)
    - Seabrook Station (Ref. E.2-16)
3. SQN Individual Plant Examination (IPE), SQN Individual Plant Examination of External Events (IPEEE) reports and their updates,
4. NUREG-1742, Perspectives Gained From the Individual Plant Examination of External Events (IPEEE) Program; and
5. SQN updated PRA model lists of risk significant contributors (Ref. E.2-12).

The comprehensive list contained a total of 309 Phase I SAMA candidates and is available in onsite documentation.

E.2.2 Phase I SAMA Analysis – Qualitative Screening

The purpose of the Phase I analysis is to use high-level knowledge of the plant and SAMAs to preclude the need to perform detailed cost-benefit analyses on them. Since many of the SAMAs were derived from industry sources, they include a variety of potential enhancements that may or may not be directly applicable to SQN. In addition, several candidate SAMAs initially considered may or may not have already been implemented at SQN. Each SAMA was initially categorized by successive screening by one of six criteria discussed below. Potential SAMA candidates were screened out if they modified features not applicable to SQN, if they had already been implemented at SQN, if they were similar in nature and could be combined with another SAMA candidate to develop a more comprehensive or plant-specific SAMA candidate, if they had excessive implementation cost, if they had very low benefit to SQN, or if implementation of this SAMA is already in progress.

- Not Applicable: If a proposed SAMA does not apply to the SQN design, it is not retained.
- Already Implemented: If the SAMA or equivalent was previously implemented, it is not retained.
- Combined With Another SAMA: If a SAMA is similar in nature and can be combined with another SAMA to develop a more comprehensive or plant specific SAMA, only the combined SAMA is further evaluated.
- Excessive Implementation Cost: If the estimated cost of implementation is greater than the modified Maximum Averted Cost-Risk, the SAMA cannot be cost beneficial and is screened from further analysis.
- Very Low Benefit: If the SAMA is related to a non-risk significant system which is known to have negligible impact on the risk profile, it is not retained.
- Implementation in Progress: If plant improvements that address the intent of the SAMA are already in progress, it is not retained.

During this process, 262 SAMA candidates were screened out based on the criteria listed above. Table E.2-1 provides a description of each of the 47 Phase II SAMA candidates.

E.2.3 Phase II SAMA Analysis – Cost Benefit Evaluation

A cost/benefit analysis was performed on each of the remaining 47 SAMA candidates. If the implementation cost of a SAMA candidate was determined to be greater than the potential benefit (i.e. there was a negative net value) the SAMA candidate was considered not to be cost beneficial and was not retained as a potential enhancement.

The expected cost of implementation of each SAMA was established from existing estimates of similar modifications combined with engineering judgment. Most of the cost estimates were developed from similar modifications considered in previous performed SAMA analyses. In particular, these cost-estimates were derived from the following major sources including:

- Watts Bar Nuclear Plant SAMA Analysis (Ref. E.2-2)
- Columbia Generating Station SAMA Analysis (Ref. E.2-3)
- Kewaunee Power Station SAMA Analysis (Ref. E.2-5)
- Wolf Creek Generating Station SAMA Analysis (Ref. E.2-7)

- D.C. Cook Nuclear Plant SAMA Analysis (Ref. E.2-9)

Detailed cost estimates were often not required to make informed decisions regarding the economic viability of a potential plant enhancement when compared to attainable benefit. Several of the SAMA candidates were clearly in excess of the attainable benefit estimated from a particular analysis. For less clear cases, engineering judgment was applied to determine if a more detailed cost estimate was necessary to formulate a conclusion regarding the economic viability of a particular SAMA. In most cases, more detailed cost estimates were not required, particularly if the SAMA called for the implementation of a hardware modification. Nonetheless, the cost of SAMA candidates was conceptually estimated to the point where conclusions regarding the economic viability of the proposed modification could be adequately gauged.

Based on a review of previous submittals SAMA evaluations and an evaluation of expected implementation costs at SQN, the following estimated costs for each type of proposed SAMA implementation were used. The lower value in each range was generally assumed to be the minimum cost for that type of SAMA implementation.

Type of Change	Estimated Cost Range
Procedural only	$50,000
Procedural change with engineering required	$50,000 - $200,000
Procedural change with engineering and testing/training required	$200,000 - $300,000
Hardware modification	$100,000 - >$1,000,000

Detailed cost estimates were based on the engineering judgment of project engineers experienced in performing design changes at the facility and these values were compared, where possible, to estimates developed and used at plants of similar design and vintage.

Bounding evaluations were performed to address the generic nature of the initial SAMA concepts. Such bounding calculations overestimate the benefit and thus are conservative calculations. For example, one SAMA dealt with installing digital large break LOCA protection; the bounding calculation estimated the benefit of this improvement by total elimination of risk due to large break LOCA (see analysis in Phase II SAMA 147 below). Such a calculation obviously overestimated the benefit, but if the inflated benefit indicated that the SAMA is not cost-beneficial, then the purpose of the analysis was satisfied.

A description of the analyses used in the Phase II analysis follows.

SAMA 008: Increase training on response to loss of two 120V AC buses which causes inadvertent actuation signals.

Training is currently conducted on inadvertent Safety Injection and loss of a single 120V AC bus, but not on loss of two 120V AC buses. To assess the benefit of increased training on loss of two 120V AC buses which causes inadvertent actuation signals, the inadvertent actuation of Safety Injection was removed from the model. This is a bounding analysis since increased training would not eliminate all inadvertent actuations.

With the model changes discussed above, the averted cost risk relative to the base case $573 for Unit 1, and $226 for Unit 2.

SAMA 014: Provide Backup Gas Turbine Generator

Installing a gas turbine generator would increase the availability of on-site AC power (namely to the shutdown boards). A new event, failure of the gas turbine generator, was added to the Diesel Generator Supply logic so that failure of the Diesel Generators and failure of the gas turbine generator are required to lose power to the shutdown boards. The failure probability of the gas turbine generator, taken from NUREG-6928 (Ref. E.2-13), was assumed to be 4.54E-02.

With the model changes discussed above, the averted cost risk relative to the base case $125,289 for Unit 1, and $49,495 for Unit 2.

SAMA 032: Emergency Core Cooling Automatic Alignment

Automating the alignment of high pressure recirculation from the RWST to the containment sumps would eliminate the human error in performing this manual action. As the RWST level drops and containment sumps fill due to Safety Injection after a small LOCA, a manual action is required to align high pressure recirculation. Automating this alignment would eliminate the need for manual action HARR1. A bounding analysis was performed by eliminating the failure of this manual action, setting the event to false. No failure mechanisms of the automatic alignment were introduced to the model (failure of level control valves, check valves), since their contribution to this scenario is minimal.

With the model changes discussed above, the averted cost risk relative to the base case $457,637 for Unit 1, and $1,025,677 for Unit 2.

SAMA 045: Enhance procedural guidance for use of cross-tied component cooling pumps.

Enhancing procedural guidance for the use of cross-tied component cooling water pumps would reduce the frequency of loss of component cooling water. The Component Cooling System (CCS) at SQN is designed such that two pumps are capable of servicing the A Train CCS Heat Exchangers, and two pumps are capable of servicing the B Train Heat Exchangers. There are a total of five CCS pumps between both units (1A-A, 1B-B, C-S, 2A-A, and 2B-B). Current configuration of the CCS allows for pumps 1A-A and 1B-B to supply heat exchangers 1A1 and 1A2, pump C-S supplies heat exchangers 0B1 and 0B2, and pumps 2A-A and 2B-B supply heat exchangers 2A1 and 2A2. When pump C-S is in maintenance, the system is designed to allow either pump 1B-B or 2B-B to supply heat exchangers 0B1 and 0B2.

Enhanced procedural guidance could allow for increased flexibility of pump configuration. For example, if both pumps 1A-A and 1B-B were unavailable, the system could be aligned such that pump C-S supplied heat exchangers 1A1 and 1A2, pump 2B-B supplied heat exchangers 0B1 and 0B2, and pump 2A-A continued to supply heat exchangers 2A1 and 2A2. The CCS fault trees were modified so that failure of multiple pumps was required to cease flow to the respective heat exchanger train. Under the new configuration for example, failure to deliver flow to Unit 1 CCS Train A requires the failure of pumps 1A-A, 1B-B, C-S.

With the model changes discussed above, the averted cost risk relative to the base case $83,686 for Unit 1, and $71,548 for Unit 2.

SAMA 046: Add a Service Water Pump

This analysis was used to evaluate the change in plant risk from installing new service water pump. A new service water pump with failure on demand and fail to run basic events was added to the PRA model under ERCW pump failure gates. The probabilities for these basic events were taken from failure on demand and fail to run for the existing pumps.

With the model changes discussed above, the averted cost risk relative to the base case $78,656 for Unit 1, and $28,722 for Unit 2.

SAMA 055 - Install an independent reactor coolant pump seal injection system, with dedicated diesel.
SAMA 056 - Install an independent reactor coolant pump seal injection system, without dedicated diesel.

Installing an independent reactor coolant pump seal injection system with a dedicated diesel would reduce the frequency of core damage from loss of component cooling water, service water, or station blackout. The analysis was performed by adding a new seal injection system to the fault tree logic such that RCP Seal Injection Failure would require failure of the new system and both centrifugal charging pumps. The new seal injection system is composed of one pump and two valves with failure rates of 1.1E-02 and 1.2E-03, respectively. No power dependencies were included as part of this addition to the model.

With the model changes discussed above, the averted cost risk relative to the base case $289,715 for Unit 1, and $184,009 for Unit 2.

SAMA 068: Add a Motor-Driven Auxiliary Feedwater Pump

Adding a motor-driven feedwater pump would increase the availability of feedwater. A bounding analysis was performed by removing the initiating events for total and partial loss of feedwater. Additionally, the fault tree was modified to include an additional feedwater pump. The failure probability of the pump was assumed to be 0.05, and no dependencies on power or other support system was modeled.

With the model changes discussed above, the averted cost risk relative to the base case $1,112,211 for Unit 1, and $1,303,463 for Unit 2.

SAMA 070: Install accumulators for turbine-driven auxiliary feedwater pump flow control valves.

Installing accumulators for turbine-driven auxiliary feedwater pump flow control valves would eliminate the need for local manual action to align nitrogen bottles for control air following a loss of off-site power. A bounding analysis was performed by eliminating the failure of the existing flow control valves.

With the model changes discussed above, the averted cost risk relative to the base case $348,010 for Unit 1, and $311,460 for Unit 2.

SAMA 071: Install a new Condensate Storage Tank

This analysis was used to evaluate the change in plant risk of increasing the availability of auxiliary feedwater by installing a new condensate storage tank. A bounding analysis was performed by assuming that long term makeup to the CST was always available.

With the model changes discussed above, the averted cost risk relative to the base case $179,100 for Unit 1, and $509 for Unit 2.

SAMA 079: Replace existing pilot-operated relief valves (PORVs) with larger ones, such that only one is required for successful feed and bleed.

This analysis was used to evaluate the change in plant risk from replacing existing pilot-operated relief valves (PORVs) with larger ones, such that only one is required for successful feed and bleed. Feed and Bleed operation using Safety Injection pumps currently requires both PORVs to function properly. The analysis was performed by modifying the fault tree logic such that failure to establish RCS bleed with PORVs using Safety Injection pumps would require the failure of both PORVs instead of just one. RCS feed and bleed using centrifugal charging pumps currently only requires one PORV to function properly, therefore, no change was made to the fault tree logic for feed and bleed using CCPs.

With the model changes discussed above, the averted cost risk relative to the base case $318 for Unit 1, and $0 for Unit 2.

SAMA 083: Add a Switchgear Room High Temperature Alarm

Installing a high temperature alarm in the switchgear room would improve diagnosis of a loss of switchgear HVAC. A bounding analysis was performed by eliminating the failure of the ventilation fans in the 480V Transformer Room, thereby maintaining a proper temperature in the room.

With the model changes discussed above, the averted cost risk relative to the base case $764 for Unit 1, and $3,986 for Unit 2.

SAMA 087: Replace Service and Instrument Air Compressors with more reliable compressors which have self-contained air cooling by shaft driven fans.

Replacing service and instrument air compressors with more reliable compressors which have self-contained air cooling by shaft driven fans would eliminate instrument air system dependence on service water cooling. A bounding analysis was performed by eliminating the failure of cooling to the compressors. This includes compressors for the auxiliary compressed air system and the compressed air system. Conservatively, no additional failure mechanisms of the replacement compressors were introduced to the model.

With the model changes discussed above, the averted cost risk relative to the base case $326,089 for Unit 1, and $292,809 for Unit 2.

However, the compressed air system at SQN (SCSA and ACAS) is common to both units. Improvements to the compressed air system would therefore benefit both units, with the combined total averted cost risk being $618,898.

SAMA 088: Install nitrogen bottles as backup gas supply for safety relief valves.

Installing nitrogen bottles as backup gas supply for safety relief valves would extend the operation time and increase the availability of the SRVs. A bounding analysis was performed by modifying the atmospheric relief valve fault tree logic to remove their dependence on compressed air. The dependence on the compressed air system was removed for all four ARV's for each unit.

With the model changes discussed above, the averted cost risk relative to the base case $78,098 for Unit 1, and $79,007 for Unit 2.

SAMA 103 – Institute Simulator Training for Severe Accident Scenarios

This analysis was used to evaluate the change in plant risk from decreasing the failure probabilities of human actions through upgrading the plant simulator for training on severe accidents. A bounding analysis was performed by reducing the failure probability of important human actions. The HEP dependency factors for important human actions were also improved.

With the model changes discussed above, the averted cost risk relative to the base case $371,973 for Unit 1, and $397,065 for Unit 2.

SAMA 105: Delay Containment Spray Actuation after a Large LOCA
SAMA 106: Install Automatic Containment Spray Pump Header Throttle Valves
SAMA 249: High Volume Makeup to the RWST

The intent of SAMA 105 – Delay containment spray actuation after a large LOCA, SAMA 106 - Install automatic containment spray pump header throttle valves, and SAMA

249 – High Volume Makeup to the RWST, is to extend the availability of the RWST. Therefore, SAMA 105, SAMA 106, and SAMA 249 have been analyzed together. A bounding analysis was performed by changing the model so that the RWST was always available. This included removing RWST tank rupture, as well as failure to deliver flow from the RWST to Containment Spray Pumps A and B. Extending the availability of the RWST would also decrease the importance of switching to containment sump recirculation. Therefore, the failure probability of the human action to align high pressure recirculation (HARR1), was decreased by half to account for the increased time that the operator would have to perform this action.

With the model changes discussed above, the averted cost risk relative to the base case $256,588 for Unit 1, and $539,396 for Unit 2.

SAMA 109: Install a Passive Hydrogen Control System

Installing a passive hydrogen control system would reduce the potential for a hydrogen detonation inside containment. Since the hydrogen mitigation system has negligible impacts on CDF, a bounding analysis was performed by eliminating the failure of the existing hydrogen mitigation system from Level 2 model logic. .

With the model changes discussed above, the averted cost risk relative to the base case $892,930 for Unit 1, and $811,466 for Unit 2.

SAMA 111: Install additional pressure or leak monitoring instruments for detection of ISLOCAs.
SAMA 239: Install additional instrumentation for ISLOCA detection.

This analysis was used to evaluate the change in plant risk from installing additional pressure or leak monitoring instruments for detection of ISLOCAs. A bounding analysis was performed by removing certain initiating events that could lead to an ISLOCA. The ISLOCA initiating events removed were for the Letdown Line, RHR Legs, RHR Pump Seal, RHR Supply, RSWT Piping, SI Legs, and SI Pump Seals.

With the model changes discussed above, the averted cost risk relative to the base case $30,128 for Unit 1, and $26,769 for Unit 2.

SAMA 112: Add redundant and diverse limit switches to each containment isolation valve.

Adding redundant and diverse limit switches to each containment isolation valve would reduce the frequency of containment isolation failures and ISLOCAs. A bounding analysis was performed by adding a manual action to the fault tree logic at each containment isolation valve. This action replicates manually closing containment isolation valves that either failed to transfer close or unintentionally opened. The human action was given a failure probability of 1E-02 regardless of where the action was to be performed (e.g., inside containment). The change to the model did not account for any potential failure of the limit switches.

With the model changes discussed above, the averted cost risk relative to the base case $255 for Unit 1, and $0 for Unit 2.

SAMA 136: Install Motor Generator Set Trip Breakers in Control Room SAMA 137: Provide Capability to Remove Power from the Bus Powering the Control Rods

This analysis was used to evaluate the change in plant risk from reducing core damage frequency due to an ATWS. During an ATWS, if the MCR HS is ineffective in opening the Reactor Trip Breakers, there is a manual action to open local breakers. Installing motor generator set trip breakers (SAMA 136) or providing capability to remove power to the bus powering the control rods (SAMA 137) would eliminate the need for this local manual action. A bounding analysis was performed by eliminating the failure of the manual action to trip the reactor using the MCR hand switch (HAEB1). Additionally, probability of failure to trip the reactor, given SSPS (HART1) was reduced by half. This reduced the probability for failure of this manual action to below the original cognitive error probability, and is thus conservative.

With the model changes discussed above, the averted cost risk relative to the base case $25,603 for Unit 1, and $22,473 for Unit 2.

SAMA 147: Install digital large break LOCA protection system.

This analysis was used to evaluate the change in plant risk from installing a digital large break LOCA protection system. A bounding analysis was performed by removing the initiating events for large break and medium break LOCAs on each cold leg.

With the model changes discussed above, the averted cost risk relative to the base case $2,277 for Unit 1, and $1,697 for Unit 2.

SAMA 160: Implement Procedures for Temporary HVAC

This analysis case was performed to evaluate implementing procedures for temporary HVAC in areas of the plant not addressed by other ventilation related SAMAs (e.g., EDG Building, Shutdown Transformer Room). The analysis was performed by adding a human action to provide temporary cooling (failure frequency of 1E-01) for the following areas given cooler/ventilation failure: Turbine-Driven AFW Pump Room; RHR Pump Rooms A and B; SI Pump Rooms A and B, Containment Spray Room; CCP Cooler Rooms A and B; and Space Coolers A and B for Boric Acid Transfer Pump and AFW Pumps.

With the model changes discussed above, the averted cost risk relative to the base case $664,540 for Unit 1, and $219,877 for Unit 2.

SAMA 161: Provide backup ventilation for the EDG rooms, should their normal HVAC supply fail.

This analysis was used to evaluate the change in plant risk from providing backup ventilation for the EDG rooms should their normal HVAC supply fail. A bounding analysis was performed by eliminating failure of the dampers and exhaust fans which provide ventilation to the EDGs and Electric Board Room.

With the model changes discussed above, the averted cost risk relative to the base case $81,080 for Unit 1, and $38,275 for Unit 2.

However, the diesel generators are modeled such that the 1A and 1B EDGs could supply power to Unit 2 Shutdown Boards, and vice-versa. Improvements to the diesel generator room ventilation system would therefore benefit both units, with the combined total averted cost risk being $119,355.

SAMA 167: Enhance Air Return Fans

Providing an independent power supply for the air return fans would potentially reduce containment failure probability during SBO sequences. The air return fans inside containment are dependent on power from the 480V Shutdown Boards. The analysis for this case was performed by removing this power dependency of the containment fans on the 480V boards to simulate an independent power supply.

With the model changes discussed above, the averted cost risk relative to the base case $255 for Unit 1, and $0 for Unit 2.

SAMA 188: Implement modifications to the Compressed Air System to increase the capacity of the system.

This analysis was used to evaluate the change in plant risk from modifications to the compressed air system to increase their reliability and decrease their time in maintenance. To assess the benefit of increasing the capacity of the system, the failure probability of the compressors and dryers for the compressed air and auxiliary compressed air systems was set to zero. It is assumed in the analysis that increasing the capacity of the system would increase the availability and reliability. The probability of the dyers and compressors being in maintenance was also set to zero to represent improved reliability of the system. Completely removing these failures from the PRA model provides a bounding and conservative analysis.

With the model changes discussed above, the averted cost risk relative to the base case $466,910 for Unit 1, and $424,175 for Unit 2.

However, the compressed air system at SQN (SCSA and ACAS) is common to both units. Improvements to the compressed air system would therefore benefit both units, with the combined total averted cost risk being $891,085.

SAMA 215: Provide a Means to Ensure RCP Seal Cooling so that RCP Seal LOCAs are Precluded from SBO Events

This analysis was used to evaluate the change in plant risk from providing a means to ensure RCP seal cooling so that RCP seal LOCAs are precluded for SBO events. The analysis was performed by adding an additional seal cooling system to the logic. The new seal cooling system with independent power source was given an unavailability of 0.05 which is representative of a single pump train system. The new seal cooling system was "anded" with the existing RCP Thermal Barrier Cooling logic. The previous RCP Thermal Barrier Cooling was then replaced where it originally appeared in the fault tree logic by the new alternate seal cooling arrangement, where the both cooling systems would be required to fail to result in a loss of cooling induced RCP Seal LOCA.

With the model changes discussed above, the averted cost risk relative to the base case $3,832,192 for Unit 1, and $3,234,126 for Unit 2.

SQN is currently planning the installation of improved RCP Seals. Installation of improved RCP seals would decrease the importance of RCP Seal LOCAs and would have an impact on the results of this analysis. Providing a means to ensure RCP seal cooling so that RCP seal LOCAs are precluded for SBO events may no longer be a cost-beneficial plant improvement after the installation of the new seals.

SAMA 218: Improve Reliability of Power Supplies

This analysis was used to evaluate the change in plant risk from improving the reliability of power supplies. To assess the benefit of replacing or improving power supplies, the failure probabilities of all batteries, battery chargers, buses, circuit breakers, and transformers were decreased by ten percent. Additionally, the frequencies of loss of off-site power events due to switchyard centered and plant centered events were also decreased by 10 percent. A ten percent improvement in reliability of power supplies is conservative due to the reliability of the existing power supplies. Achieving a ten percent improvement was judged to be the maximum reasonable improvement without a major re-design and upgrade of the power supplies.

With the model changes discussed above, the averted cost risk relative to the base case $167,926 for Unit 1, and $140,703 for Unit 2.

SAMA 226: Install Permanent, Self-Powered Pump to Backup Normal Charging Pump
SAMA 240: Install Permanent Dedicated Diesel for Normal Charging Pump

This analysis was used to evaluate the change in plant risk from increasing the availability of normal charging through adding a permanent, self-powered backup pump, or installing a permanent dedicated diesel for the normal charging pumps. A bounding analysis was performed by eliminating the failure of both centrifugal charging pumps.

With the model changes discussed above, the averted cost risk relative to the base case $302,964 for Unit 1, and $193,139 for Unit 2.

SAMA 254: Install Alternate Fuel Oil Tank with Gravity Feed Capability

Installing an alternate fuel oil tank with gravity feed capability would increase the reliability of the diesel generators. The installation of a large volume gravity feed alternate fuel oil tank would decrease the probability of fail to run events due to fuel oil transfer pump failures. To assess this potential benefit, diesel generator fail to run events (including common cause failures) were decreased by ten percent. From industry data, failure of the fuel oil transfer pump contributes less than 8% of the diesel generator fail to run probability. Therefore, a ten percent improvement in fail to run events (including common cause) is a conservative assumption.

With the model changes discussed above, the averted cost risk relative to the base case $29,107 for Unit 1, and $12,947 for Unit 2.

SAMA 268: Perform an Evaluation of the CCS/AFW Area Cooling Requirements

A realistic room heat-up analysis would determine the cooling requirements that are currently performed by the CCS and AFW Space Coolers and establish whether or not these coolers are required for the PRA mission time of 24 hours. Eliminating the dependency of the CCS and AFW pumps on these space coolers would increase the availability of the pumps in the PRA model. The analysis was performed eliminating the failure of the CCS and AFW Space Coolers.

With the model changes discussed above, the averted cost risk relative to the base case $2,269,398 for Unit 1, and $1,881,472 for Unit 2.

SAMA 275: Install Spray Protection on Motor-Driven Auxiliary Feedwater Pumps and AFW Pump Space Coolers

This analysis was used to evaluate the change in plant risk from installing spray protection equipment (spray shields) on the motor-driven Auxiliary Feedwater pumps and space coolers used to cool MDAFW pumps. A bounding analysis was performed by eliminating spray initiators from the MDAFW pumps, and space coolers used to cool MDAFW pumps. The Unit 1 space coolers protected in this analysis were the CCS/AFW Space Coolers. The Unit 2 space coolers protected in this analysis were the AFW/BAT Space Coolers.

With the model changes discussed above, the averted cost risk relative to the base case $586,656 for Unit 1, and $791,774 for Unit 2.

SAMA 276: Replace one or more existing SG Atmospheric Relief Valves with a different design or manufacturer.

Replacing one or more existing SG atmospheric relief valves with a valve of different design or manufacturer would potentially decrease or eliminate common cause failures between the valves. A bounding analysis was performed by eliminating all of the common cause failures of steam generator atmospheric relief valves.

With the model changes discussed above, the averted cost risk relative to the base case $49,275 for Unit 1, and $56,157 for Unit 2.

SAMA 277: Improve Reliability of Control Rod Mechanisms

Improving the reliability of control rod mechanisms would reduce the likelihood of an ATWS event. The analysis was performed by decreasing the probability of control rods failing to insert by an order of magnitude.

With the model changes discussed above, the averted cost risk relative to the base case $156,357 for Unit 1, and $139,307 for Unit 2.

SAMA 278: Improve Reliability of RHR Pumps

This analysis was used to evaluate the change in plant risk from improving maintenance procedures on RHR pumps to reduce common cause failures and increase the availability of RHR system. The analysis was performed by decreasing by half the probabilities of RHR pumps failure on demand, fail to run, common cause, and unavailability due to maintenance events. Reducing the failure probability of these events by fifty percent is conservative since it is unlikely that any modifications to procedures would result in such a large increase in pump reliability and availability.

With the model changes discussed above, the averted cost risk relative to the base case $105,811 for Unit 1, and $116,232 for Unit 2.

SAMA 279: Improve Internal Flooding Response Procedures and Training to Improve the Response to Internal Flooding Events

This analysis was used to evaluate the change in plant risk from improving procedures and training of important human actions following an internal flooding event. Improved procedures and training would result in a decreased failure probability of human actions in response to a flooding event. The analysis was performed by reducing the overall failure probability of important flooding human actions, with the flood multiplier for important human actions reduced by a factor of two. A fifty-percent reduction in the flood multiplier is conservative since it is unlikely that any amount of training would result in such a dramatic decrease in the failure to perform these actions following an internal flood.

With the model changes discussed above, the averted cost risk relative to the base case $520,201 for Unit 1, and $796,041 for Unit 2.

SAMA 283 – Provide Frequent Awareness Training to Plant Staff on Important Human Actions

This analysis was used to evaluate the change in plant risk from instituting frequent awareness training on important human actions. Increased awareness of important human actions has the potential to decrease the failure probabilities of those actions. A bounding analysis was performed by reducing the failure probability of important human actions by ten percent. The HEP dependency factors for important human actions were also improved by ten percent. Given the relatively low failure probability of these important human actions, an improvement of ten percent due to increased training is deemed to be a conservative and reasonable assumption.

With the model changes discussed above, the averted cost risk relative to the base case $371,973 for Unit 1, and $397,065 for Unit 2.

SAMA 284: Improve Reliability of Pressurizer Safety Relief Valves

Reducing the probability that the pressurizer safety relief valves fail to reclose following a water pressure event would decrease the likelihood of a small LOCA type scenario. A bounding analysis was performed by eliminating the failure of the pressurizer safety relief valves to reseat after a water pressure event.

With the model changes discussed above, the averted cost risk relative to the base case $88,946 for Unit 1, and $60,875 for Unit 2.

SAMA 285: Protect Important Equipment in the Turbine Building from Internal Flooding

This analysis was used to evaluate the change in plant risk from installing flood mitigation equipment to protect vital equipment in the turbine building basement. The analysis was performed by adding a factor to the flooding initiators that resulted in spray damage to the Turbine Building Distribution Boards and the Raw Cooling Water Pumps to simulate addition of spray shields. The spray shield was given a failure probability of 1E-03.

With the model changes discussed above, the averted cost risk relative to the base case $478,481 for Unit 1, and $439,418 for Unit 2.

The Turbine Building Distribution Boards and the Raw Cooling Water Pumps are common or shared between the two units. Therefore, protecting this equipment from flooding impacts would have a benefit to both units, with the combined total averted cost risk being $917,899.

SAMA 286: Install Flood Doors to Prevent Water Propagation in the Electric Board Room

This analysis was used to evaluate the change in plant risk from installing flood/watertight doors in and near the electric board room to prevent the propagation of floods. The analysis was performed by removing the failure of important equipment from certain floods to simulate watertight doors. The intent of this potential SAMA is to prevent internal flooding initiators from impacting both trains of vital shutdown equipment. Installation of flood doors would prohibit water from propagating to both trains of the 6.9 kV shutdown board rooms and the 480V board rooms. In the analysis, a flood initiating in or impacting A-Train rooms would not be allowed to propagate to the B-Train rooms (e.g., flood initiating in 6.9 kV Shutdown Board Room A will not propagate to 6.9 kV Shutdown Board Room B or 480 V Shutdown Rooms B1 or B2), and vice versa. Additionally, since there are no flood sources in 125 V Vital Battery Board Rooms II and III, equipment in these rooms are protected from all floods.

With the model changes discussed above, the averted cost risk relative to the base case $1,611,330 for Unit 1, and $1,453,681 for Unit 2.

However, installing flood doors to prevent water propagation in the Electric Board Room would benefit both units, with the combined total averted cost risk being $3,065,011.

SAMA 287: Protect, re-route, or modify circuits to upgrade core damage mitigation capability for fires that result in MCR evacuation.

This analysis was used to evaluate the change in plant risk from upgrading core damage mitigation capability for fires that result in Main Control Room Evacuation by protecting, re-routing, or modifying circuits to ensure an additional mitigation train is available in the Auxiliary Control Room.

Four of the fire compartments remaining in the final Fire IPEEE screening phase account for ~35% of the IPEEE fire CDF. These four fire compartments all include a severe fire scenario which results in evacuation of the Main Control Room. The four compartments are Unit 1 Auxiliary Instrument Room (685.0-C01), Unit 2 Auxiliary Instrument Room (685.0-C04), Main Control Room (732.0-C12) and Relay Room (732.C13). Each of the MCR evacuation scenarios assumes a conditional core damage probability of 0.074. A potential SAMA to address fire risk is to implement modifications that would reduce the CCDP associated with MCR evacuation. The modifications would include changes that would make an additional mitigation train available in the Auxiliary Control Room. This SAMA is evaluated by assuming the control room evacuation CCDP is reduced by an order of magnitude to 7.4E-3.

With the model changes discussed above, the averted cost risk relative to the base case $397,595 for Unit 1, and $308,398 for Unit 2.

SAMA 288: Install Spray Protection on Component Cooling Pumps and CCS/AFW Space Coolers

This analysis was used to evaluate the change in plant risk from installing spray protection equipment (spray shields) on the Component Cooling System pumps and CCS/AFW space coolers used to cool the component cooling pumps for both units. A bounding analysis was performed by eliminating spray initiator events from the CCS pumps and CCS/AFW space coolers fault tree logic. The Unit 1, Unit 2, and common component cooling pumps are all located in the area that is cooled by the CCS/AFW space coolers.

With the model changes discussed above, the averted cost risk relative to the base case $792,705 for Unit 1, and $669,470 for Unit 2.

CCS/AFW Space Coolers A and B are shared coolers that support operation of the common, Unit 1, and Unit 2 component cooling pumps. The combined total averted cost risk for implementation of this SAMA is $1,462,175.

SAMA 289: Install Backup Cooling System for CCS/AFW Space Coolers

This analysis was used to evaluate the change in plant risk from installing a backup cooling system to increase the reliability of the CCS/AFW Space Coolers. The analysis was performed by adding a backup space cooler to the fault tree logic, such that failure of the existing and backup coolers is required for failure of the CCS and AFW Space Coolers. The failure probabilities of the backup space cooler (failure on demand and fail to run) were taken from the existing space coolers.

With the model changes discussed above, the averted cost risk relative to the base case $1,628,978 for Unit 1, and $1,163,772 for Unit 2.

CCS/AFW Space Coolers A and B are shared coolers that support operation of the common, Unit 1, and Unit 2 component cooling pumps, as well as both Unit 1 MDAFW. The combined total averted cost risk for implementation of this SAMA is $2,792,750.

E.2.4 Sensitivity Analyses

Two sensitivity analyses were conducted to gauge the impact of key assumptions upon the analysis. The benefits (averted cost-risk) of each SAMA analysis with these sensitivities are presented in Table E.2-3 for Unit 1 and Table E.2-4 for Unit 2.

The sensitivities performed are as follows:

Sensitivity Case 1: Conservative Discount Rate

The purpose of this sensitivity case was to investigate the sensitivity of each analysis case to the discount rate. The discount rate of 7.0% used in the base case analyses is conservative relative to corporate practices; nonetheless, a lower discount rate of 3.0% was assumed in this case to investigate the impact on each analysis case.

Sensitivity Case 1: 95th Percentile Uncertainty

The purpose of this sensitivity case was to investigate the sensitivity of the PRA model underestimating averted plant risk. If the best estimate failure probability values were consistently lower than the "actual" failure probabilities, the PRA model would underestimate plant risk and yield lower than "actual" averted cost-risk values for potential SAMAs. Re-assessing the cost benefit calculations using the high end of the failure probability distributions is a means of identifying the impact of having consistently underestimated failure probabilities for plant equipment and operator actions included in the PRA model. This sensitivity uses a multiplier of 2.5, which is conservative with respect to the CDF 95th percentile results, to examine the impact of uncertainty in the PRA model.

E.2.5 References

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E.2-2 R-2361441-1823, "Watts Bar Unit 2 Severe Accident Mitigation Alternatives," October 4, 2010.

E.2-3 NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Columbia Generating Station – Draft Report for Comment (NUREG-1437, Supplement 47)," August 2011.

E.2-4 NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Cooper Nuclear Station, Unit 1 – Final Report (NUREG-1437, Supplement 41)," July 2010.

E.2-5 NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regarding Kewaunee Power Station – Final Report, (NUREG-1437, Supplement 40)," August 2010.

E.2-6 NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regarding Vogtle Electric Generating Plant, Units 1 and 2 (NUREG-1437, Supplement 34)," December 2008.

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E.2-8 NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regarding Donald C. Cook Nuclear Plant, Units No. 1 and 2 – Final Report (NUREG-1437, Supplement 20)," May 2005.

E.2-9 NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regarding Catawba Nuclear Station, Units 1 and 2 – Final Report (NUREG-1437, Supplement 9)," December 2002.

E.2-10 NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regarding McGuire Nuclear Station, Units 1 and 2 – Final Report (NUREG-1437, Supplement 8)," December 2002.

E.2-11 NUREG/CR-6928, "Industry-Average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants," February 2007.

E.2-12 NUREG-1742, "Perspectives Gained From the Individual Plant Examination of External Events (IPEEE) Program – Final Report," April, 2002.

E.2-13 NUREG/CR-6928, "Industry-Average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants," February 2007.

E.2-14 NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regarding Palo Verde Nuclear Generating Station – Final Report (NUREG-1437, Supplement 43)," January 2011.

E.2-15 NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regarding Crystal River Unit 3 Nuclear Generating Plant – Draft Report for Comment (NUREG-1437, Supplement 44)," May 2011.

E.2-16 NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regarding Seabrook Station – Draft Report for Comment (NUREG-1437, Supplement 46)," July 2011.

Table E.2-1 – Unit 1 Summary of Phase II SAMA Candidates							
Unit 1 SAMA	**Source**	**CDF Reduction (%)**	**Population Dose Reduction (%)**	**Off-Site Economic Cost Reduction (%)**	**Internal and External Benefit ($)**	**SQN Cost Estimate ($)**	**Conclusion**
008 – Increase training on response to loss of two 120V AC buses	Minimum Procedure Cost	0.03%	0.00%	0.00%	$573	$50,000	Not Cost-Beneficial
014 - Install a gas turbine generator	Implementation Cost from Watts Bar[2]	0.35%	2.44%	1.65%	$125,289	$3,350,000	Not Cost-Beneficial
032 - Automatically align emergency core cooling system to recirculation	Implementation Cost from Watts Bar[2]	13.36%	4.22%	2.89%	$457,637	$2,100,000	Not Cost-Beneficial
045 - Enhance procedural guidance for use of cross-tied component cooling pumps	Minimum Procedure Cost	0.80%	1.11%	1.24%	$83,686	$50,000	Potentially Cost-Beneficial
046 – Add a service water pump	Implementation Cost from Watts Bar[2]	0.70%	1.11%	1.13%	$78,656	$1,042,511	Not Cost-Beneficial
055 - Install an independent reactor coolant pump seal injection system, with dedicated diesel	Implementation Cost from Watts Bar[2]	2.95%	4.00%	4.02%	$289,715	$8,233,000	Not Cost-Beneficial
056 - Install an independent reactor coolant pump seal injection system, without dedicated diesel	Implementation Cost from Watts Bar[2]	2.95%	4.00%	4.02%	$289,715	$8,233,000	Not Cost-Beneficial

Table E.2-1 – Unit 1 Summary of Phase II SAMA Candidates

Unit 1 SAMA	Source	CDF Reduction (%)	Population Dose Reduction (%)	Off-Site Economic Cost Reduction (%)	Internal and External Benefit ($)	SQN Cost Estimate ($)	Conclusion
068 –Add a motor-driven feedwater pump	Implementation Cost from Columbia [3]	20.44%	13.11%	11.86%	$1,112,211	$10,000,000	Not Cost-Beneficial
070 - Install accumulators for TDAFW flow control valves	Implementation Cost from Watts Bar[2]	6.05%	4.89%	3.20%	$348,010	$256,204	Potentially Cost-Beneficial
071 - Install a new condensate storage tank	Implementation Cost from Watts Bar[2]	1.22%	2.89%	2.47%	$179,100	$1,709,586	Not Cost-Beneficial
079 - Replace existing pilot-operated relief valves with larger ones	Minimum Hardware Cost	0.02%	0.00%	0.00%	$318	$100,000	Not Cost-Beneficial
083 – Add a switchgear room high temperature alarm	Minimum Hardware Cost	0.04%	0.00%	0.00%	$764	$100,000	Not Cost-Beneficial
087 - Replace service and instrument air compressors with more reliable compressors	Implementation Cost from Watts Bar[2]	6.54%	4.22%	2.78%	$326,089	$886,205*	Not Cost-Beneficial
088 - Install nitrogen bottles as backup gas supply for SRVs	Minimum Hardware Cost	3.48%	0.22%	0.21%	$78,098	$100,000	Not Cost-Beneficial
103 - Institute simulator training for severe accident scenarios	Implementation Cost from Watts Bar[2]	5.33%	4.44%	4.85%	$371,973	$8,000,000	Not Cost-Beneficial

Table E.2-1 – Unit 1 Summary of Phase II SAMA Candidates							
Unit 1 SAMA	Source	CDF Reduction (%)	Population Dose Reduction (%)	Off-Site Economic Cost Reduction (%)	Internal and External Benefit ($)	SQN Cost Estimate ($)	Conclusion
105 - Delay containment spray actuation after a large LOCA	Minimum Hardware Cost	6.83%	2.67%	1.75%	$256,588	$100,000	Potentially Cost-Beneficial
106 - Install automatic containment spray pump header throttle valves	Minimum Hardware Cost	6.83%	2.67%	1.75%	$256,588	$100,000	Potentially Cost-Beneficial
109 -Install a passive hydrogen control system	Implementation Cost from Watts Bar[2]	0.01%	14.44%	16.08%	$892,930	$3,736,000	Not Cost-Beneficial
111 - Install additional pressure or leak monitoring instruments for detection of ISLOCAs	Implementation Cost from Columbia [3]	0.11%	0.67%	0.31%	$30,128	$190,000	Not Cost-Beneficial
112 - Add redundant and diverse limit switches to each containment isolation valve	Implementation Cost from Watts Bar[2]	0.01%	0.00%	0.00%	$255	$691,524	Not Cost-Beneficial
136 - Install motor generator set trip breakers in control room	Minimum Hardware Cost	0.20%	0.44%	0.31%	$25,603	$100,000	Not Cost-Beneficial
137 - Provide capability to remove power from the bus powering the control rods	Minimum Hardware Cost	0.20%	0.44%	0.31%	$25,603	$100,000	Not Cost-Beneficial

Table E.2-1 – Unit 1 Summary of Phase II SAMA Candidates							
Unit 1 SAMA	**Source**	**CDF Reduction (%)**	**Population Dose Reduction (%)**	**Off-Site Economic Cost Reduction (%)**	**Internal and External Benefit ($)**	**SQN Cost Estimate ($)**	**Conclusion**
147 -Install digital large break LOCA protection system	Implementation Cost from D. C. Cook [8]	0.12%	0.00%	0.00%	$2,227	$2,700,000	Not Cost-Beneficial
160 - Implement procedures for temporary HVAC	SQN Estimate	9.10%	7.78%	9.07%	$664,540	$300,000	Potentially Cost-Beneficial
161 - Provide backup ventilation for the EDG rooms	Minimum Hardware Cost	0.49%	1.33%	1.13%	$81,080	$1,000,000*	Not Cost-Beneficial
167 – Provide an independent power supply for the air return fans	Minimum Hardware Cost	0.01%	0.00%	0.00%	$255	$100,000	Not Cost-Beneficial
188 - Implement modifications to the compressed air system to increase the capacity of the system	SQN Estimate	11.20%	5.33%	3.51%	$466,910	$2,782,200	Not Cost-Beneficial
215 - Provide a means to ensure RCP seal cooling so that RCP seal LOCAs are precluded for SBO events	Implementation Cost from Watts Bar[2]	47.52%	46.22%	54.12%	$3,832,192	$1,500,000	Potentially Cost-Beneficial
218 – Improve reliability of power supplies to reduce reactor trip frequency	SQN Estimate	2.78%	1.78%	2.16%	$167,926	$500,000	Not Cost-Beneficial

Table E.2-1 – Unit 1 Summary of Phase II SAMA Candidates

Unit 1 SAMA	Source	CDF Reduction (%)	Population Dose Reduction (%)	Off-Site Economic Cost Reduction (%)	Internal and External Benefit ($)	SQN Cost Estimate ($)	Conclusion
226 – Install a permanent, self-powered pump to backup normal charging pump	Implementation Cost from Watts Bar[2]	2.99%	4.22%	4.23%	$302,964	$2,700,000	Not Cost-Beneficial
239 – Install additional instrumentation for ISLOCA detection	Implementation Cost from Kewaunee [5]	0.11%	0.67%	0.31%	$30,128	$190,000	Not Cost-Beneficial
240 - Install permanent dedicated generator for normal charging pump	Implementation Cost from Kewaunee [5]	2.99%	4.22%	4.23%	$302,964	$2,000,000	Not Cost-Beneficial
249 – High Volume Makeup to the RWST	Implementation Cost from Wolf Creek [7]	6.83%	2.67%	1.75%	$256,588	$565,000	Not Cost-Beneficial
254 – Install an alternate Fuel Oil Tank with gravity feed capability	Implementation Cost from Wolf Creek [7]	0.22%	0.44%	0.41%	$29,107	$150,000	Not Cost-Beneficial
268 – Perform an Evaluation of the CCS/AFW Area Cooling Requirements	SQN Estimate	29.51%	26.89%	31.65%	$2,269,398	$313,000	Potentially Cost-Beneficial
275 - Install Spray Protection on MDAFW Pumps and AFW Pump Space Coolers	SQN Estimate	7.95%	6.89%	8.04%	$586,656	$800,000	Not Cost-Beneficial

Table E.2-1 – Unit 1 Summary of Phase II SAMA Candidates

Unit 1 SAMA	Source	CDF Reduction (%)	Population Dose Reduction (%)	Off-Site Economic Cost Reduction (%)	Internal and External Benefit ($)	SQN Cost Estimate ($)	Conclusion
276 – Replace one or more existing SG atmospheric relief valves with a valve of different design or manufacturer	SQN Estimate	1.62%	0.44%	0.21%	$49,275	$1,233,000	Not Cost-Beneficial
277 – Improve reliability of control rod mechanisms	SQN Estimate	1.34%	2.89%	1.65%	$156,357	$1,218,780	Not Cost-Beneficial
278 - Improve the reliability of the RHR pumps and improve maintenance procedures to reduce potential for common cause failure	SQN Estimate	3.30%	0.67%	0.82%	$105,811	$345,095	Not Cost-Beneficial
279 - Improve Internal Flooding Response Procedures and Training to Improve the Response to Internal Flooding Events	SQN Estimate	5.25%	7.33%	7.11%	$520,201	$400,000	Potentially Cost-Beneficial
283 – Provide Frequent Awareness Training to Plant Staff on Important Human Actions	SQN Estimate	5.33%	4.44%	4.85%	$371,973	$345,095	Potentially Cost-Beneficial

Table E.2-1 – Unit 1 Summary of Phase II SAMA Candidates

Unit 1 SAMA	Source	CDF Reduction (%)	Population Dose Reduction (%)	Off-Site Economic Cost Reduction (%)	Internal and External Benefit ($)	SQN Cost Estimate ($)	Conclusion
284 - Reduce the probability that the pressurizer safety relief valves fail to reclose following a water pressure relief event	Minimum Hardware Cost	2.40%	0.67%	0.82%	$88,946	$1,566,800	Not Cost-Beneficial
285 - Protect Important Equipment in the Turbine Building from Internal Flooding	SQN Estimate	8.83%	5.78%	4.95%	$478,481	$954,900*	Not Cost-Beneficial
286 - Install Flood Doors to Prevent Water Propagation in the Electric Board Room	SQN Estimate	10.81%	26.00%	22.37%	$1,611,330	$4,695,100*	Not Cost-Beneficial
287 - Protect, re-route, or modify circuits to upgrade core damage mitigation capability for fires that result in MCR evacuation	Implementation Cost from Columbia [3]	5.20%	5.11%	5.15%	$397,595	$2,000,000	Not Cost-Beneficial
288 - Install Spray Protection on CCS Pumps and CCS/AFW Space Coolers	SQN Estimate	8.94%	9.78%	11.55%	$792,705	$1,808,700*	Not Cost-Beneficial
289 - Install backup cooling system for CCS/AFW Space Coolers	SQN Estimate	21.69%	19.11%	22.58%	$1,628,978	$2,218,700*	Not Cost-Beneficial

* Due to the nature of this SAMA, the cost of implementation can be shared between Unit 1 and Unit 2. The cost estimate for full implementation is presented here and in Table E.2-2. The combined benefit is presented in Section 2.3.

Table E.2-2 – Unit 2 Summary of Phase II SAMA Candidates							
Unit 2 **SAMA**	**Source**	**CDF Reduction (%)**	**Population Dose Reduction (%)**	**Off-Site Economic Cost Reduction (%)**	**Internal and External Benefit ($)**	**SQN Cost Estimate ($)**	**Conclusion**
008 – Increase training on response to loss of two 120V AC buses	Minimum Procedure Cost	0.01%	0.00%	0.00%	$226	$50,000	Not Cost-Beneficial
014 - Install a gas turbine generator	Implementation Cost from Watts Bar[2]	0.10%	1.14%	0.75%	$49,495	$3,350,000	Not Cost Beneficial
032 - Automatically align emergency core cooling system to recirculation	Implementation Cost from Watts Bar[2]	31.80%	8.88%	6.77%	$1,025,677	$2,100,000	Not Cost Beneficial
045 - Enhance procedural guidance for use of cross-tied component cooling pumps	Minimum Procedure Cost	0.64%	1.14%	1.18%	$71,548	$50,000	Potentially Cost-Beneficial
046 – Add a service water pump	Implementation Cost from Watts Bar[2]	0.32%	0.46%	0.43%	$28,722	$1,042,511	Not Cost Beneficial
055 - Install an independent reactor coolant pump seal injection system, with dedicated diesel	Implementation Cost from Watts Bar[2]	2.36%	2.51%	2.90%	$184,009	$8,233,000	Not Cost Beneficial

Table E.2-2 – Unit 2 Summary of Phase II SAMA Candidates

Unit 2 SAMA	Source	CDF Reduction (%)	Population Dose Reduction (%)	Off-Site Economic Cost Reduction (%)	Internal and External Benefit ($)	SQN Cost Estimate ($)	Conclusion
056 - Install an independent reactor coolant pump seal injection system, without dedicated diesel	Implementation Cost from Watts Bar[2]	2.36%	2.51%	2.90%	$184,009	$8,233,000	Not Cost Beneficial
068 –Add a motor-driven feedwater pump	Implementation Cost from Columbia [3]	33.25%	13.90%	11.60%	$1,303,463	$10,000,000	Not Cost Beneficial
070 - Install accumulators for TDAFW flow control valves	Implementation Cost from Watts Bar[2]	5.12%	5.01%	3.33%	$311,460	$256,204	Potentially Cost Beneficial
071 - Install a new condensate storage tank	Implementation Cost from Watts Bar[2]	0.03%	0.00%	0.00%	$509	$1,709,586	Not Cost Beneficial
079 - Replace existing pilot-operated relief valves with larger ones	Minimum Hardware Cost	0.00%	0.00%	0.00%	$0	$100,000	Not Cost Beneficial
083 – Add a switchgear room high temperature alarm	Implementation Cost from D. C. Cook [8]	0.06%	0.00%	0.11%	$3,986	$100,000	Not Cost Beneficial
087 - Replace service and instrument air compressors with more reliable compressors	Implementation Cost from Watts Bar[2]	5.59%	4.33%	2.90%	$292,809	$886,205*	Not Cost Beneficial

Table E.2-2 – Unit 2 Summary of Phase II SAMA Candidates

Unit 2 SAMA	Source	CDF Reduction (%)	Population Dose Reduction (%)	Off-Site Economic Cost Reduction (%)	Internal and External Benefit ($)	SQN Cost Estimate ($)	Conclusion
088 - Install nitrogen bottles as backup gas supply for SRVs	Minimum Hardware Cost	3.13%	0.46%	0.21%	$79,007	$100,000	Not Cost Beneficial
103 - Institute simulator training for severe accident scenarios	Implementation Cost from Watts Bar[2]	6.61%	5.01%	5.48%	$397,065	$8,000,000	Not Cost Beneficial
105 - Delay containment spray actuation after a large LOCA	Minimum Hardware Cost	16.04%	5.01%	3.76%	$539,396	$100,000	Potentially Cost Beneficial
106 - Install automatic containment spray pump header throttle valves	Minimum Hardware Cost	16.04%	5.01%	3.76%	$539,396	$100,000	Potentially Cost Beneficial
109 -Install a passive hydrogen control system	Implementation Cost from Watts Bar[2]	0.00%	15.03%	16.97%	$811,466	$3,736,000	Not Cost Beneficial
111 - Install additional pressure or leak monitoring instruments for detection of ISLOCAs	Implementation Cost from Columbia [3]	0.08%	0.68%	0.32%	$26,769	$190,000	Not Cost Beneficial
112 - Add redundant and diverse limit switches to each containment isolation valve	Implementation Cost from Watts Bar[2]	0.00%	0.00%	0.00%	$0	$691,524	Not Cost Beneficial

Table E.2-2 – Unit 2 Summary of Phase II SAMA Candidates							
Unit 2 SAMA	**Source**	**CDF Reduction (%)**	**Population Dose Reduction (%)**	**Off-Site Economic Cost Reduction (%)**	**Internal and External Benefit ($)**	**SQN Cost Estimate ($)**	**Conclusion**
136 - Install motor generator set trip breakers in control room	Minimum Hardware Cost	0.15%	0.46%	0.32%	$22,473	$100,000	Not Cost Beneficial
137 - Provide capability to remove power from the bus powering the control rods	Minimum Hardware Cost	0.15%	0.46%	0.32%	$22,473	$100,000	Not Cost Beneficial
147 -Install digital large break LOCA protection system	Implementation Cost from D. C. Cook [8]	0.09%	0.00%	0.00%	$1,697	$2,700,000	Not Cost Beneficial
160 - Implement procedures for temporary HVAC	SQN Estimate	5.02%	2.28%	2.47%	$219,877	$300,000	Not Cost Beneficial
161 - Provide backup ventilation for the EDG rooms	Minimum Hardware Cost	0.24%	0.68%	0.64%	$38,275	$1,000,000*	Not Cost Beneficial
167 – Provide an independent power supply for the air return fans	Minimum Hardware Cost	0.00%	0.00%	0.00%	$0	$100,000	Not Cost Beneficial
188 - Implement modifications to the compressed air system to increase the capacity of the system	SQN Estimate	9.67%	5.47%	3.76%	$424,175	$2,782,200	Not Cost-Beneficial

Table E.2-2 – Unit 2 Summary of Phase II SAMA Candidates

Unit 2 SAMA	Source	CDF Reduction (%)	Population Dose Reduction (%)	Off-Site Economic Cost Reduction (%)	Internal and External Benefit ($)	SQN Cost Estimate ($)	Conclusion
215 - Provide a means to ensure RCP seal cooling so that RCP seal LOCAs are precluded for SBO events	Implementation Cost from Watts Bar[2]	38.45%	44.19%	53.17%	$3,234,126	$1,500,000	Potentially Cost-Beneficial
218 – Improve reliability of power supplies to reduce reactor trip frequency	SQN Estimate	2.15%	1.82%	2.04%	$140,703	$500,000	Not Cost Beneficial
226 – Install a permanent, self-powered pump to backup normal charging pump	Implementation Cost from Watts Bar[2]	2.40%	2.73%	3.01%	$193,139	$2,700,000	Not Cost Beneficial
239 – Install additional instrumentation for ISLOCA detection	Implementation Cost from Kewaunee [5]	0.08%	0.68%	0.32%	$26,769	$190,000	Not Cost Beneficial
240 - Install permanent dedicated generator for normal charging pump	Implementation Cost from Kewaunee [5]	2.40%	2.73%	3.01%	$193,139	$2,000,000	Not Cost Beneficial
249 – High Volume Makeup to the RWST	Implementation Cost from Wolf Creek [7]	16.04%	5.01%	3.76%	$539,396	$565,000	Not Cost Beneficial
254 – Install an alternate Fuel Oil Tank with gravity feed capability	Implementation Cost from Wolf Creek [7]	0.09%	0.23%	0.21%	$12,947	$150,000	Not Cost Beneficial

Table E.2-2 – Unit 2 Summary of Phase II SAMA Candidates

Unit 2 SAMA	Source	CDF Reduction (%)	Population Dose Reduction (%)	Off-Site Economic Cost Reduction (%)	Internal and External Benefit ($)	SQN Cost Estimate ($)	Conclusion
268 – Perform an Evaluation of the CCS/AFW Area Cooling Requirements	SQN Estimate	21.34%	25.97%	31.47%	$1,881,472	$313,000	Potentially Cost-Beneficial
275 - Install Spray Protection on MDAFW Pumps and AFW Pump Space Coolers	SQN Estimate	17.76%	8.43%	8.92%	$791,774	$800,000	Not Cost-Beneficial
276 – Replace one or more existing SG atmospheric relief valves with a valve of different design or manufacturer	SQN Estimate	1.98%	0.46%	0.21%	$56,157	$1,233,000	Not Cost Beneficial
277 – Improve reliability of control rod mechanisms	SQN Estimate	1.10%	2.96%	1.72%	$139,307	$1,218,780	Not Cost Beneficial
278 - Improve the reliability of the RHR pumps and improve maintenance procedures to reduce potential for common cause failure	SQN Estimate	2.90%	1.14%	1.18%	$116,232	$345,095	Not Cost Beneficial
279 - Improve Internal Flooding Response Procedures and Training to Improve the Response to Internal Flooding Events	SQN Estimate	14.87%	10.02%	9.77%	$796,041	$400,000	Potentially Cost-Beneficial

Table E.2-2 – Unit 2 Summary of Phase II SAMA Candidates

Unit 2 SAMA	Source	CDF Reduction (%)	Population Dose Reduction (%)	Off-Site Economic Cost Reduction (%)	Internal and External Benefit ($)	SQN Cost Estimate ($)	Conclusion
283 – Provide Frequent Awareness Training to Plant Staff on Important Human Actions	SQN Estimate	6.61%	5.01%	5.48%	$397,065	$345,095	Potentially Cost Beneficial
284 - Reduce the probability that the pressurizer safety relief valves fail to reclose following a water pressure relief event	Minimum Hardware Cost	1.80%	0.46%	0.54%	$60,875	$1,566,800	Not Cost Beneficial
285 - Protect Important Equipment in the Turbine Building from Internal Flooding	SQN Estimate	7.62%	6.15%	5.26%	$439,418	$954,900*	Not Cost Beneficial
286 - Install Flood Doors to Prevent Water Propagation in the Electric Board Room	SQN Estimate	9.09%	26.88%	23.52%	$1,453,681	$4,695,100*	Not Cost-Beneficial
287 - Protect, re-route, or modify circuits to upgrade core damage mitigation capability for fires that result in MCR evacuation	Implementation Cost from Columbia [3]	4.40%	4.33%	4.40%	$308,398	$2,000,000	Not Cost Beneficial
288 - Install Spray Protection on CCS Pumps and CCS/AFW Space Coolers	SQN Estimate	6.94%	9.57%	11.39%	$669,470	$1,808,700*	Not Cost Beneficial

Table E.2-2 – Unit 2 Summary of Phase II SAMA Candidates							
Unit 2 **SAMA**	**Source**	**CDF Reduction (%)**	**Population Dose Reduction (%)**	**Off-Site Economic Cost Reduction (%)**	**Internal and External Benefit ($)**	**SQN Cost Estimate ($)**	**Conclusion**
289 - Install backup cooling system for CCS/AFW Space Coolers	SQN Estimate	13.66%	15.95%	19.23%	$1,163,772	$2,218,700*	Not Cost Beneficial

* Due to the nature of this SAMA, the cost of implementation can be shared between Unit 1 and Unit 2. The cost estimate for full implementation is presented here and in Table E.2-1. The combined benefit is presented in Section 2.3

Table E.2-3 – Unit 1 Sensitivity Analyses				
SAMA Number and Title	**Internal and External Benefit Original**	**Sensitivity Case 1, 3% Discount Rate**	**Sensitivity Case 2, 95th Percentile Uncertainty**	**SQN Cost Estimate**
SAMA 008 – Increase training on response to loss of two 120V AC buses which causes inadvertent actuation signals.	$573	$707	$1,432	$50,000
SAMA 014 - Install a gas turbine generator to increase availability of on-site AC power.	$125,289	$173,982	$313,224	$3,350,000
SAMA 032 - Add the ability to automatically align emergency core cooling system to recirculation mode upon refueling water storage tank depletion.	$457,637	$598,369	$1,144,092	$2,100,000
SAMA 045 - Enhance procedural guidance for use of cross-tied component cooling pumps.	$83,686	$114,486	$209,216	$50,000
SAMA 046 – Add a service water pump to increase the availability of cooling water.	$78,656	$107,769	$196,640	$1,042,511
SAMA 055 - Install an independent reactor coolant pump seal injection system, with dedicated diesel.	$289,715	$395,747	$724,287	$8,233,000
SAMA 056 - Install an independent reactor coolant pump seal injection system, without dedicated diesel.	$289,715	$395,747	$724,287	$8,233,000
SAMA 068 –Add a motor-driven feedwater pump.	$1,112,211	$1,491,259	$2,780,527	$10,000,000
SAMA 070 - Install accumulators for turbine-driven auxiliary feedwater pump flow control valves.	$348,010	$467,682	$870,024	$256,204
SAMA 071 - Install a new condensate storage tank.	$179,100	$246,503	$447,750	$1,709,586

Table E.2-3 – Unit 1 Sensitivity Analyses

SAMA Number and Title	Internal and External Benefit Original	Sensitivity Case 1, 3% Discount Rate	Sensitivity Case 2, 95th Percentile Uncertainty	SQN Cost Estimate
SAMA 079 - Replace existing pilot-operated relief valves with larger ones, such that only one is required for successful feed and bleed.	$318	$393	$796	$100,000
SAMA 083 – Add a switchgear room high temperature alarm.	$764	$942	$1,909	$100,000
SAMA 087 - Replace service and instrument air compressors with more reliable compressors which have self-contained air cooling by shaft driven fans.	$326,089	$435,532	$815,222	$886,205
SAMA 088 - Install nitrogen bottles as backup gas supply for safety relief valves.	$78,098	$98,411	$195,246	$100,000
SAMA 103 - Institute simulator training for severe accident scenarios.	$371,973	$503,371	$929,932	$8,000,000
SAMA 105 - Delay containment spray actuation after a large LOCA.	$256,588	$337,532	$641,471	$100,000
SAMA 106 - Install automatic containment spray pump header throttle valves.	$256,588	$337,532	$641,471	$100,000
SAMA 109 -Install a passive hydrogen control system.	$892,930	$1,247,700	$2,232,324	$3,736,000
SAMA 111 - Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	$30,128	$41,766	$75,319	$190,000

Table E.2-3 – Unit 1 Sensitivity Analyses

SAMA Number and Title	Internal and External Benefit Original	Sensitivity Case 1, 3% Discount Rate	Sensitivity Case 2, 95th Percentile Uncertainty	SQN Cost Estimate
SAMA 112 - Add redundant and diverse limit switches to each containment isolation valve.	$255	$314	$636	$691,524
SAMA 136 - Install motor generator set trip breakers in control room.	$25,603	$35,164	$64,009	$100,000
SAMA 137 - Provide capability to remove power from the bus powering the control rods.	$25,603	$35,164	$64,009	$100,000
SAMA 147 -Install digital large break LOCA protection system.	$2,227	$2,749	$5,569	$2,700,000
SAMA 160 - Implement procedures for temporary HVAC.	$664,540	$900,598	$1,661,350	$300,000
SAMA 161 - Provide backup ventilation for the EDG rooms, should their normal HVAC supply fail.	$81,080	$111,780	$202,700	$1,000,000
SAMA 167 – Provide an independent power supply for the air return fans.	$255	$314	$636	$100,000
SAMA 188 - Implement modifications to the compressed air system to increase the capacity of the system.	$466,910	$617,971	$1,167,276	$2,782,200
SAMA 215 - Provide a means to ensure RCP seal cooling so that RCP seal LOCAs are precluded for SBO events.	$3,832,192	$5,208,695	$9,580,481	$1,500,000
SAMA 218 – Improve reliability of power supplies to reduce reactor trip frequency.	$167,926	$226,084	$419,814	$500,000

Table E.2-3 – Unit 1 Sensitivity Analyses

SAMA Number and Title	Internal and External Benefit Original	Sensitivity Case 1, 3% Discount Rate	Sensitivity Case 2, 95th Percentile Uncertainty	SQN Cost Estimate
SAMA 226 – Install a permanent, self- powered pump to backup normal charging pump.	$302,964	$414,136	$757,409	$2,700,000
SAMA 239 – Install additional instrumentation for ISLOCA detection.	$30,128	$41,766	$75,319	$190,000
SAMA 240 - Install permanent dedicated generator for normal charging pump.	$302,964	$414,136	$757,409	$2,000,000
SAMA 249 – High Volume Makeup to the RWST	$256,588	$337,532	$641,471	$565,000
SAMA 254 – Install an alternate Fuel Oil Tank with gravity feed capability.	$29,107	$39,996	$72,766	$150,000
SAMA 268 – Perform an Evaluation of the CCS/AFW Area Cooling Requirements	$2,269,398	$3,080,344	$5,673,495	$313,000*
SAMA 275 - Install Spray Protection on Motor-Driven Auxiliary Feedwater Pumps and Space Coolers	$586,656	$795,313	$1,466,641	$800,000
SAMA 276 – Replace one or more existing SG atmospheric relief valves with a valve of different design or manufacturer.	$49,275	$63,864	$123,187	$1,223,000
SAMA 277 – Improve reliability of control rod mechanisms.	$156,357	$214,359	$390,894	$1,218,780
SAMA 278 - Improve the reliability of the RHR pumps and improve maintenance procedures to reduce potential for common cause failure.	$105,811	$137,707	$264,526	$345,095

Table E.2-3 – Unit 1 Sensitivity Analyses				
SAMA Number and Title	**Internal and External Benefit Original**	**Sensitivity Case 1, 3% Discount Rate**	**Sensitivity Case 2, 95th Percentile Uncertainty**	**SQN Cost Estimate**
SAMA 279 - Improve Internal Flooding Response Procedures and Training to Improve the Response to Important Human Actions	$520,201	$710,759	$1,300,503	$400,000
SAMA 283 – Initiate frequent awareness training for plant operators/ maintenance/ testing staff on important human actions, including dependent (combination) events, for plant risk.	$371,973	$503,371	$929,932	$345,095
SAMA 284 - Reduce the probability that the pressurizer safety relief valves fail to reclose following a water pressure relief event.	$88,946	$116,896	$222,365	$1,566,800
SAMA 285 - Protect Important Equipment in the Turbine Building from Internal Flooding	$478,481	$641,428	$1,196,201	$954,900*
SAMA 286 - Install Flood Doors to Prevent Water Propagation in the Electric Board Room	$1,611,330	$2,218,329	$4,028,324	$4,695,100*
SAMA 287 - Protect, re-route, or modify circuits to upgrade core damage mitigation capability for fires that result in MCR evacuation	$397,595	$539,577	$993,987	$2,000,000
SAMA 288 - Install Spray Protection on Component Cooling Pumps and Space Coolers	$792,705	$1,080,168	$1,981,762	$1,808,700*
SAMA 289 - Install backup cooling system for CCS and AFW space coolers.	$1,628,978	$2,209,509	$4,072,444	$2,218,700*

* Due to the nature of this SAMA, the cost of implementation can be shared between Unit 1 and Unit 2. The cost estimate for full implementation is presented here and in Table E.2-4. The benefit presented in this table is only for Unit 1.

Table E.2-4 – Unit 2 Sensitivity Analyses				
SAMA Number and Title	**Internal and External Benefit Original**	**Sensitivity Case 1, 3% Discount Rate**	**Sensitivity Case 2, 95th Percentile Uncertainty**	**SQN Cost Estimate**
SAMA 008 – Increase training on response to loss of two 120V AC buses which causes inadvertent actuation signals.	$226	$280	$566	$50,000
SAMA 014 - Install a gas turbine generator to increase availability of on-site AC power.	$49,495	$68,857	$123,738	$3,350,000
SAMA 032 - Add the ability to automatically align emergency core cooling system to recirculation mode upon refueling water storage tank depletion.	$1,025,677	$1,333,077	$2,564,192	$2,100,000
SAMA 045 - Enhance procedural guidance for use of cross-tied component cooling pumps.	$71,548	$97,950	$178,871	$50,000
SAMA 046 – Add a service water pump to increase the availability of cooling water.	$28,722	$39,129	$71,804	$1,042,511
SAMA 055 - Install an independent reactor coolant pump seal injection system, with dedicated diesel.	$184,009	$249,684	$460,021	$8,233,000
SAMA 056 - Install an independent reactor coolant pump seal injection system, without dedicated diesel.	$184,009	$249,684	$460,021	$8,233,000
SAMA 068 –Add a motor-driven feedwater pump.	$1,303,463	$1,716,684	$3,258,658	$10,000,000

Table E.2-4 – Unit 2 Sensitivity Analyses				
SAMA Number and Title	**Internal and External Benefit Original**	**Sensitivity Case 1, 3% Discount Rate**	**Sensitivity Case 2, 95th Percentile Uncertainty**	**SQN Cost Estimate**
SAMA 070 - Install accumulators for turbine-driven auxiliary feedwater pump flow control valves.	$311,460	$419,099	$778,651	$256,204
SAMA 071 - Install a new condensate storage tank.	$509	$631	$1,273	$1,709,586
SAMA 079 - Replace existing pilot-operated relief valves with larger ones, such that only one is required for successful feed and bleed.	$0	$0	$0	$100,000
SAMA 083 – Add a switchgear room high temperature alarm.	$3,986	$5,382	$9,965	$100,000
SAMA 087 - Replace service and instrument air compressors with more reliable compressors which have self-contained air cooling by shaft driven fans.	$292,809	$391,556	$732,023	$886,205
SAMA 088 - Install nitrogen bottles as backup gas supply for safety relief valves.	$79,007	$100,527	$197,518	$100,000
SAMA 103 - Institute simulator training for severe accident scenarios.	$397,065	$534,017	$992,663	$8,000,000
SAMA 105 - Delay containment spray actuation after a large LOCA.	$539,396	$703,209	$1,348,490	$100,000
SAMA 106 - Install automatic containment spray pump header throttle valves.	$539,396	$703,209	$1,348,490	$100,000

Table E.2-4 – Unit 2 Sensitivity Analyses

SAMA Number and Title	Internal and External Benefit Original	Sensitivity Case 1, 3% Discount Rate	Sensitivity Case 2, 95th Percentile Uncertainty	SQN Cost Estimate
SAMA 109 -Install a passive hydrogen control system.	$811,466	$1,133,917	$2,028,665	$3,736,000
SAMA 111 - Install additional pressure or leak monitoring instruments for detection of ISLOCAs.	$26,769	$37,154	$66,922	$190,000
SAMA 112 - Add redundant and diverse limit switches to each containment isolation valve.	$0	$0	$0	$691,524
SAMA 136 - Install motor generator set trip breakers in control room.	$22,473	$30,945	$56,183	$100,000
SAMA 137 - Provide capability to remove power from the bus powering the control rods.	$22,473	$30,945	$56,183	$100,000
SAMA 147 -Install digital large break LOCA protection system.	$1,697	$2,102	$4,242	$2,700,000
SAMA 160 - Implement procedures for temporary HVAC.	$219,877	$291,448	$549,692	$300,000
SAMA 161 - Provide backup ventilation for the EDG rooms, should their normal HVAC supply fail.	$38,275	$52,739	$95,687	$1,000,000
SAMA 167 – Provide an independent power supply for the air return fans.	$0	$0	$0	$100,000

Table E.2-4 – Unit 2 Sensitivity Analyses				
SAMA Number and Title	**Internal and External Benefit Original**	**Sensitivity Case 1, 3% Discount Rate**	**Sensitivity Case 2, 95th Percentile Uncertainty**	**SQN Cost Estimate**
SAMA 188 - Implement modifications to the compressed air system to increase the capacity of the system.	$424,175	$562,267	$1,060,438	$2,782,200
SAMA 215 - Provide a means to ensure RCP seal cooling so that RCP seal LOCAs are precluded for SBO events.	$3,234,126	$4,398,108	$8,085,314	$1,500,000
SAMA 218 – Improve reliability of power supplies to reduce reactor trip frequency.	$140,703	$189,826	$351,756	$500,000
SAMA 226 – Install a permanent, self-powered pump to backup normal charging pump.	$193,139	$262,326	$482,847	$2,700,000
SAMA 239 – Install additional instrumentation for ISLOCA detection.	$26,769	$37,154	$66,922	$190,000
SAMA 240 - Install permanent dedicated generator for normal charging pump.	$193,139	$262,326	$482,847	$2,000,000
SAMA 249 – High Volume Makeup to the RWST	$539,396	$703,209	$1,348,490	$565,000
SAMA 254 – Install an alternate Fuel Oil Tank with gravity feed capability.	$12,947	$17,813	$32,367	$150,000
SAMA 268 – Perform an Evaluation of the CCS/AFW Area Cooling Requirements	$1,881,472	$2,561,872	$4,703,680	$313,000*

Table E.2-4 – Unit 2 Sensitivity Analyses				
SAMA Number and Title	Internal and External Benefit Original	Sensitivity Case 1, 3% Discount Rate	Sensitivity Case 2, 95th Percentile Uncertainty	SQN Cost Estimate
SAMA 275 - Install Spray Protection on Motor-Driven Auxiliary Feedwater Pumps and Space Coolers	$791,774	$1,050,458	$1,979,434	$800,000
SAMA 276 – Replace one or more existing SG atmospheric relief valves with a valve of different design or manufacturer.	$56,157	$72,223	$140,392	$1,223,000
SAMA 277 – Improve reliability of control rod mechanisms.	$139,307	$191,205	$348,267	$1,218,780
SAMA 278 - Improve the reliability of the RHR pumps and improve maintenance procedures to reduce potential for common cause failure.	$116,232	$153,297	$290,579	$345,095
SAMA 279 - Improve Internal Flooding Response Procedures and Training to Improve the Response to Important Human Actions	$796,041	$1,065,514	$1,990,103	$400,000
SAMA 283 – Initiate frequent awareness training for plant operators/ maintenance/ testing staff on important human actions, including dependent (combination) events, for plant risk.	$397,065	$534,017	$992,663	$345,095
SAMA 284 - Reduce the probability that the pressurizer safety relief valves fail to reclose following a water pressure relief event.	$60,875	$79,400	$152,188	$1,566,800

Table E.2-4 – Unit 2 Sensitivity Analyses

SAMA Number and Title	Internal and External Benefit Original	Sensitivity Case 1, 3% Discount Rate	Sensitivity Case 2, 95th Percentile Uncertainty	SQN Cost Estimate
SAMA 285 - Protect Important Equipment in the Turbine Building from Internal Flooding	$439,418	$590,030	$1,098,546	$954,900*
SAMA 286 - Install Flood Doors to Prevent Water Propagation in the Electric Board Room	$1,453,681	$2,002,676	$3,634,203	$4,695,100*
SAMA 287 - Protect, re-route, or modify circuits to upgrade core damage mitigation capability for fires that result in MCR evacuation	$308,398	$417,083	$770,995	$2,000,000
SAMA 288 - Install Spray Protection on Component Cooling Pumps and Space Coolers	$669,470	$913,622	$1,673,675	$1,808,700*
SAMA 289 - Install backup cooling system for CCS and AFW space coolers.	$1,163,772	$1,583,181	$2,909,431	$2,218,700*

* Due to the nature of this SAMA, the cost of implementation can be shared between Unit 1 and Unit 2. The cost estimate for full implementation is presented here and in Table E.2-3. The benefit presented in this table is only for Unit 2.

END OF SECTION