Three Mile Island Nuclear Station

Applicant's Environmental Report License Renewal Operating Stage

Final

Applicant's Environmental Report – Operating License Renewal Stage Three Mile Island Nuclear Station Unit 1

AmerGen Energy Company, LLC

Docket No. 50-289

License No. DPR-50

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ACRONYMS AND ABBREVIATIONS

AADT	Annual Average Daily Traffic
AEC	[U.S.] Atomic Energy Commission
AEPS	Alternative Energy Portfolio Standards Act
AmerGen	AmerGen Energy Company, LLC
AWEA	American Wind Energy Association
BTU	British Thermal Unit
°C	degrees Celsius
CAIR	Clean Air Interstate Rule
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
cfs	cubic feet per second
CWA	Clean Water Act
DSM	Demand-side management
EPA	[U.S.] Environmental Protection Agency
ESA	Endangered Species Act
°F	degrees Fahrenheit
FERC	Federal Energy Regulatory Commission
FES	Final Environmental Statement
fps	feet per second
FSAR	Final Safety Analysis Report
FWS	[U.S.] Fish and Wildlife Service
GEIS	Generic Environmental Impact Statement for License Renewal of Nuclear Plants
gpd	gallons per day
gpm	gallons per minute
IPA	integrated plant assessment
ISFSI	Independent Spent Fuel Storage Installation
ISPH	Intake Screen and Pumphouse
km	kilometers
kV	kiloVolt
KW	kilowatt
kwh	kilowatt hours
LDSD	Lower Dauphin School District
LOS	level of service
m	meters
MGD	million gallons per day
MSA	Metropolitan Statistical Area
MW	megawatt
MWe	megawatts-electric

MWt	megawatt - thermal
NA	not applicable
NAAQS	National Ambient Air Quality Standards
NAES	Naval Air Engineering Station
NESC	National Electrical Safety Code
NMFS	National Marine Fisheries Service
NOAA	National Oceanic and Atmospheric Administration
NO_x	nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
OSG	original steam generator
pCi/l	pico-curies per liter
psig	pounds per square inch gauge
PADEP	Pennsylvania Department of Environmental Protection
PDMS	Post Defueling Monitored Storage
PENNDOT	Pennsylvania Department of Transportation
PHMC	Pennsylvania Historic and Museum Commission
PJM	Pennsylvania, New Jersey, Maryland [power pool]
$PM_{2.5}$	particulates with diameters less than 2.5 microns
PM_{10}	particulates with diameters less than 10 microns
PNHP	Pennsylvania Natural Heritage Program
PPUC	Pennsylvania Public Utility Commission
PURTA	Pennsylvania Utility Realty Tax Act
PWR	pressurized water reactor
RSG	replacement steam generator
SAMA	Severe Accident Mitigation Alternatives
SCR	selective catalytic reduction
SH	State Highway
SHPO	State Historic Preservation Officer
SIP	State Implementation Plan
SMITTR	surveillance, monitoring, inspections, testing, trending, and recordkeeping
SO_2	sulfur dioxide
SO_x	sulfur oxides
SRBC	Susquehanna River Basin Commission
TMI	Three Mile Island Nuclear Station Unit 1
tpy	tons per year
TSP	total suspended particulates
twh	terawatt hours
USCB	[U.S.] Census Bureau
USGS	[U.S.] Geological Survey
VOC	volatile organic compounds

WHC	Wildlife Habitat Council

Chapter 1

INTRODUCTION

1.1 PURPOSE OF AND NEED FOR ACTION

The U.S. Nuclear Regulatory Commission (NRC) licenses the operation of domestic nuclear power plants in accordance with the Atomic Energy Act of 1954, as amended, and NRC implementing regulations. AmerGen Energy Company, LLC (AmerGen) operates the Three Mile Island Nuclear Station Unit 1 (TMI-1), pursuant to NRC Operating License DPR-50. The license for Unit 1 will expire on April 19, 2014. TMI Unit 2, which is owned by FirstEnergy Corporation, has been permanently shut down and is now in a safe storage mode called Post Defueling Monitored Storage. The only TMI Unit 2 systems, structures or components that are relied upon for the operation of TMI-1 are the Station Blackout Diesel Generator Building and the TMI Unit 2 Fuel Handling Building. No TMI Unit 2 activities are within the scope of the TMI-1 license renewal application.

AmerGen has prepared this environmental report in conjunction with its application to NRC to renew the TMI-1 operating license, as provided by the following NRC regulations:

> Title 10, Energy, Code of Federal Regulations (CFR), Part 54, Requirements for Renewal of Operating Licenses for Nuclear Power Plants, Section 54.23, Contents of Application-Environmental Information (10 CFR 54.23) and

> Title 10, Energy, CFR, Part 51, Environmental Protection Requirements for Domestic Licensing and Related Regulatory Functions, Section 51.53, Postconstruction Environmental Reports, Subsection 51.53(c), Operating License Renewal Stage [10 CFR 51.53(c)].

NRC has defined the purpose and need for the proposed action, the renewal of the operating license for a nuclear power plant such as TMI-1, as follows:

> "...The purpose and need for the proposed action (renewal of an operating license) is to provide an option that allows for power generation capability beyond the term of a current nuclear power plant operating license to meet future system generating needs, as such needs may be determined by State, utility, and, where authorized, Federal (other than NRC) decision makers." (NRC 1996a)

The renewed operating license would allow an additional 20 years of plant operation beyond the current TMI-1 licensed operating period of approximately 40 years.

1.2 ENVIRONMENTAL REPORT SCOPE AND METHODOLOGY

NRC regulations for domestic licensing of nuclear power plants require environmental review of applications to renew operating licenses. The NRC regulation 10 CFR 51.53(c) requires that an applicant for license renewal submit with its application a separate document entitled Applicant's Environmental Report - Operating License Renewal Stage. In determining what information to include in the TMI-1 Environmental Report, AmerGen has relied on NRC regulations and the following supporting documents that provide additional insight into the regulatory requirements:

NRC supplemental information in the Federal Register (NRC 1996a, 1996b, 1996c, and 1999a);

Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) (NRC 1996d and 1999b); Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses (NRC 1996e);

Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response (NRC 1996f); and

Supplement 1 to Regulatory Guide 4.2, Preparation of Supplemental Environmental Report for Applications to Renew Nuclear Power Plant Operating Licenses (NRC 2000).

AmerGen has prepared Table 1.2-1 to verify conformance with regulatory requirements. Table 1.2-1 indicates where the environmental report responds to each requirement of 10 CFR 51.53(c). In addition, each responsive section is prefaced by a boxed quote of the regulatory language and applicable supporting document language.

1.3 THREE MILE ISLAND NUCLEAR STATION UNIT 1 LICENSEE AND OWNERSHIP

TMI-1 is owned by AmerGen Energy Company, LLC, which is a wholly owned subsidiary of Exelon Corporation, a corporation formed under the laws of the Commonwealth of Pennsylvania and headquartered in Chicago, Illinois. Exelon Corporation is one of the nation's largest electric utilities, distributing electricity to approximately 5.2 million customers in Illinois and Pennsylvania. AmerGen, which acquires and operates nuclear plants as an independent power producer in North America, is the licensed operator of TMI-1.

Table 1.2-1. Environmental Report Responses to License Renewal Environmental Regulatory Requirements

Regulatory Requirement	Responsive Environmental Report Section(s)	
10 CFR 51.53(c)(1)		Entire Document
10 CFR 51.53(c)(2), Sentences 1 and 2	3.0	Proposed Action
10 CFR 51.53(c)(2), Sentence 3	7.2.2	Environmental Impacts of Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(1)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(2)	6.3	Unavoidable Adverse Impacts
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(3)	7.0	Alternatives to the Proposed Action
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(3)	8.0	Comparison of Environmental Impacts of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(4)	6.5	Short-Term Use Versus Long-Term Productivity of the Environment
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(5)	6.4	Irreversible and Irretrievable Resource Commitments
10 CFR 51.53(c)(2) and 10 CFR 51.45(c)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
10 CFR 51.53(c)(2) and 10 CFR 51.45(c)	6.2	Mitigation
	7.2.2	Environmental Impacts of Alternatives
	8.0	Comparison of Environmental Impacts of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(d)	9.0	Status of Compliance
10 CFR 51.53(c)(2) and 10 CFR 51.45(e)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(2)	6.3	Unavoidable Adverse Impacts
10 CFR 51.53(c)(3)(ii)(A)	4.1	Water Use Conflicts (Plants with Cooling Ponds or Cooling Towers Using Makeup Water from a Small River with Low Flow)
10 CFR 51.53(c)(3)(ii)(A)	4.6	Groundwater Use Conflicts (Plants Using Cooling Water Towers or Cooling Ponds and Withdrawing Makeup Water from a Small River)
10 CFR 51.53(c)(3)(ii)(B)	4.2	Entrainment of Fish and Shellfish in Early Life Stages
10 CFR 51.53(c)(3)(ii)(B)	4.3	Impingement of Fish and Shellfish
10 CFR 51.53(c)(3)(ii)(B)	4.4	Heat Shock
10 CFR 51.53(c)(3)(ii)(C)	4.5	Groundwater Use Conflicts (Plants Using >100 gpm of Groundwater)
10 CFR 51.53(c)(3)(ii)(C)	4.7	Groundwater Use Conflicts (Plants Using Ranney Wells)

Table 1.2-1. Environmental Report Responses to License Renewal Environmental Regulatory Requirements (Continued)

Regulatory Requirement	Responsive Environmental Report Section(s)	
10 CFR 51.53(c)(3)(ii)(D)	4.8	Degradation of Groundwater Quality
10 CFR 51.53(c)(3)(ii)(E)	4.9	Impacts of Refurbishment on Terrestrial Resources
	4.10	Threatened or Endangered Species
10 CFR 51.53(c)(3)(ii)(F)	4.11	Air Quality During Refurbishment (Non-Attainment Areas)
10 CFR 51.53(c)(3)(ii)(G)	4.12	Microbiological Organisms
10 CFR 51.53(c)(3)(ii)(H)	4.13	Electric Shock from Transmission-Line-Induced Currents
10 CFR 51.53(c)(3)(ii)(I)	4.14	Housing Impacts
10 CFR 51.53(c)(3)(ii)(I)	4.15	Public Utilities: Public Water Supply Availability
10 CFR 51.53(c)(3)(ii)(I)	4.16	Education Impacts from Refurbishment
10 CFR 51.53(c)(3)(ii)(I)	4.17	Offsite Land Use
10 CFR 51.53(c)(3)(ii)(J)	4.18	Transportation
10 CFR 51.53(c)(3)(ii)(K)	4.19	Historic and Archaeological Resources
10 CFR 51.53(c)(3)(ii)(L)	4.20	Severe Accident Mitigation Alternatives
10 CFR 51.53(c)(3)(iii)	4.0	Environmental Consequences of the Proposed Action and Mitigating Actions
10 CFR 51.53(c)(3)(iii)	6.2	Mitigation
10 CFR 51.53(c)(3)(iv)	5.0	Assessment of New and Significant Information
10 CFR 51, Appendix B, Table B-1, Footnote 6	2.6.2	Minority and Low-Income Populations

1.4 REFERENCES

Note to reader: Some web pages cited in this document are no longer available, or are no longer available through the original URL addresses. Hard copies of cited web pages are available in AmerGen files. Some sites, for example the census data, cannot be accessed through their given URLs. The only way to access these pages is to follow queries on previous web pages. The complete URLs used by AmerGen have been given for these pages, even though they may not be directly accessible. Also, all references are specific to the chapter in which they are cited.

NRC (U.S. Nuclear Regulatory Commission). 1996a. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses." Federal Register. Vol. 61, No. 109. June 5.

NRC (U.S. Nuclear Regulatory Commission). 1996b. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses; Correction." Federal Register. Vol. 61, No. 147. July 30.

NRC (U.S. Nuclear Regulatory Commission). 1996c. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses." Federal Register. Vol. 61, No. 244. December 18.

NRC (U.S. Nuclear Regulatory Commission). 1996d. Generic Environmental Impact Statement for License Renewal of Nuclear Plants. Volumes 1 and 2. NUREG-1437. Washington, DC. May.

NRC (U.S. Nuclear Regulatory Commission). 1996e. Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses. NUREG-1440. Washington, DC. May.

NRC (U.S. Nuclear Regulatory Commission). 1996f. Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response. Volumes 1 and 2. NUREG-1529. Washington, DC. May.

NRC (U.S. Nuclear Regulatory Commission). 1999a. "Changes to Requirements for Environmental Review for Renewal of Nuclear Power Plant Operating Licenses; Final Rule." Federal Register. Vol. 64, No. 171. September 3.

NRC (U.S. Nuclear Regulatory Commission). 1999b. Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS). Section 6.3, "Transportation" and Table 9-1, "Summary of findings on NEPA issues for license renewal of nuclear power plants." NUREG-1437. Volume 1, Addendum 1. Washington, DC. August.

NRC (U.S. Nuclear Regulatory Commission). 2000. Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses; Supplement 1 to Regulatory Guide 4.2. Washington, DC. September.

Chapter 2

Site and Environmental Interfaces

2.1 LOCATION AND FEATURES

Three Mile Island Nuclear Station Unit 1 (TMI-1) is located in Londonderry Township in Dauphin County, Pennsylvania, on the northern end of Three Mile Island near the eastern shore of the Susquehanna River (AEC 1972). The largest communities within 10 miles of the site are the borough of Middletown, Pennsylvania, approximately three miles north of Three Mile Island, and the borough of Goldsboro, Pennsylvania, located in York County approximately 1.25 miles west of Three Mile Island across the Susquehanna River. The nearest major metropolitan area is the City of Harrisburg, Pennsylvania, approximately 10 miles to the northwest (AmerGen 2006b). Figures 2.1-1 and 2.1-2 are the 50 mile and 6-mile vicinity maps, respectively.

The TMI-1 site encompasses several properties that total approximately 440 acres. Included are: Three Mile Island, which hosts TMI-1 on approximately 200 of its 370 acres; St. John's Island and Evergreen Island (also referred to as "Sand Beach Island"), which are situated north of Three Mile Island and together total approximately 31 acres; a 6.4-acre section of Shelley Island, which is part of the western half of the TMI-1 Exclusion Area; and a 32-acre strip of land east of Three Mile Island along the eastern shore of the Susquehanna River. Three Mile Island is approximately 11,000 feet long and 1,700 feet wide with the long axis aligned north-south in the river. It lies approximately 900 feet from the east bank of the Susquehanna River and approximately 6,500 feet from the west bank of the river (Figure 2.1-3). The Susquehanna River makes a sharp change in directional flow from southeasterly to nearly due south just north of Three Mile Island where the river widens to approximately 1.5 miles wide. This widening resulted from the Red Hill and York Haven Dams, which transect the river on either side of the downstream end of Three Mile Island creating a barrier for the purpose of hydroelectric generation.

State Highway (SH)-441 parallels Three Mile Island to the east, and tracks of the Norfolk Southern Railroad parallel the Susquehanna River on the eastern and western banks. Shelley Island is located west of Three Mile Island in the middle of the river, and the borough of Goldsboro is located on the western bank of the river. The developed portion of the TMI-1 site is surrounded by a flood protection dike system. Access to the northern portion of Three Mile Island is by a bridge connecting the main entrance to the TMI-1 site and the mainland near the junction of SH-441 and Geyers Church Road. Another bridge connects the southern end of Three Mile Island with the mainland near Falmouth on SH-441 in Lancaster County (AEC 1972). The southern bridge serves as TMI-1 site access for some station personnel, outage and refurbishment workers, and construction equipment. It also provides an alternate egress route.

TMI-1 is a pressurized water reactor utilizing once-through steam generators and licensed to operate at a power level of 2,568 MWt (megawatt-thermal) (AmerGen 2006b). Certain buildings and structures associated with the Three Mile Island Nuclear Station Unit 2 (TMI-2), which is owned by FirstEnergy Corporation, are intermingled with TMI-1 buildings and structures on the TMI-1 site. TMI-2 has been shut down since March 1979. Since December 1993, it has been in a stable, safe storage mode called Post Defueling Monitored Storage (PDMS).

Section 3.1 describes key features of TMI-1, including reactor and containment systems, cooling water system, and transmission system.

2.2 AQUATIC ECOLOGY

Metropolitan Edison Company and GPU Nuclear Corporation [former owners and operators of TMI-1 and TMI-2 prior to AmerGen Energy Company, LLC (AmerGen) purchasing TMI-1] monitored water quality and aquatic organisms in the Susquehanna River up- and down-stream of Three Mile Island from 1974 through 1982 to coincide with startup and operation of TMI-1. The monitoring was intended to develop a baseline and thereby identify any significant biological alterations within the study area resulting from TMI-1 operations. This monitoring program allowed the owners to monitor the overall health of the Susquehanna River and its aquatic communities in the vicinity of Three Mile Island and to identify any chronic or recurring water quality problems or obvious impacts to aquatic communities that might be identified with operation of the Three Mile Island Nuclear Station (Ichthyological Associates 1983).

In addition to the comprehensive environmental monitoring conducted from 1974 through 1982, the owners of TMI-1 continued annual environmental monitoring through 1990. However, over time the programs and specifications changed as to frequency, sampling stations, parameters, and target aquatic community (Normandeau 2007).

2.2.1 HYDROLOGY

The Susquehanna River flows south more than 440 miles from its source, Lake Otsego in south-central New York, to Havre de Grace, Maryland, where it empties into the Chesapeake Bay. The Susquehanna River Basin (Figure 2.2-1) drains an area of about 27,500 square miles and supplies approximately 19 million gallons of fresh water per minute to the Chesapeake Bay, about half of the Bay's total freshwater inflow (Alliance for the Chesapeake Bay undated; Smithsonian Environmental Research Center 2003).

The United States Geological Survey (USGS) monitors Susquehanna River flows at Harrisburg, Pennsylvania (station 01570500). In water year 2004 (October 2003 thru September 2004) the annual mean flow was 56,400 cubic feet per second (cfs) (compared to the historic annual mean of 34,450 cfs). During that year, the Susquehanna River flow was above average every month except February, June and July (Durlin and Schaffstall 2005). Water year 2004 was a year with above average precipitation primarily caused by the remnants of four hurricanes passing through the Susquehanna River drainage. Daily mean flow ranged from 9,600 cfs (July 6) to 500,000 cfs (September 19) (Durlin and Schaffstall 2005).

2.2.2 WATER QUALITY

As stated in Section 2.2.1, Metropolitan Edison and GPU Nuclear conducted ecological studies in the vicinity of Three Mile Island from 1974 – 1982 (Ichthyological Associates, 1983). These studies were conducted to assess impacts of station operations on local aquatic communities. Data were collected on water chemistry, macroinvertebrates, and larval and adult fishes. In addition, thermal plume mapping was conducted. During 1978 (last year of operation prior to the TMI-2 accident in March 1979) both reactors were operating. TMI-1 had achieved criticality in June 1974 and TMI-2 on April 21, 1978; therefore, 1978 was the last year of data for two-unit operation (Ichthyological Associates, 1979).

Water quality parameters analyzed included turbidity, alkalinity, sulfate, total dissolved solids, total and dissolved copper, and total and dissolved zinc at stations located upstream, near the discharge structure, and downstream of the discharge structure. In addition, water temperature, pH, and dissolved oxygen were determined in the field at all sampling locations.

Mean values for dissolved oxygen, turbidity, total copper, and total zinc were highest in April while water temperature, alkalinity, sulfate, and total dissolved solids were highest in July; dissolved zinc was highest in November. Values for alkalinity, sulfate, dissolved copper, and total zinc were higher at the upstream stations in most months. Values for water temperature, dissolved oxygen, turbidity, total dissolved solids, and dissolved zinc were generally higher at the downstream stations most months. Water quality values (including water temperature) did not exceed state water quality criteria during the period when TMI-1 and TMI-2 were both operating (Ichthyological Associates, 1979).

Water temperatures were measured in the Susquehanna River as a component of ecological studies conducted by Metropolitan Edison and GPU Nuclear from 1974 – 1982 (Ichthyological Associates 1983). During this period, the Susquehanna River in the vicinity of Three Mile Island shows a predictable annual pattern of temperatures, with lowest temperatures in winter and highest temperatures in late summer. Also during this period, the TMI-1 and TMI-2 reactors achieved criticality on June 5, 1974 and April 21, 1978, respectively. Hence, the data collected from Spring 1978 through Spring 1979 reflect water temperatures with both TMI-1 and TMI-2 operating, which would be a conservative scenario. Water temperature data collected in the Susquehanna River from March 1979 through 1982 represent ambient river conditions because both reactors were shut down after an accident occurred at TMI-2. TMI-1 resumed operation in 1985.

During the sampling period from April to December 1978 (i.e., conservative conditions), temperatures taken in the Susquehanna River at locations above the discharge structure ranged from 33.8°F (December 19) to 81.5 °F (July 24). Temperatures taken in an area near the discharge structure ranged from 33.8 °F (December 19) to 81.5°F (July 24) while temperatures approximately 262.5 feet downstream of the discharge structure ranged from 33.8°F (December 19) to 85.1°F (July 24) (Ichthyological Associates 1979). These data indicate that the thermal effluent did not cause water temperatures in the Susquehanna River to exceed applicable State water quality criteria for maximum temperature (25 PA Code §93.7) and did not increase the temperature between upstream and downstream sampling points in the river by more than 5 °F. (Ichthyological Associates 1979).

AmerGen continues to collect water temperature data with an automatic temperature sensor at the intake screen pump house and at the discharge monitoring pit (before the water is mixed with the Susquehanna River water). Figure 2.2-2 presents recent representative data from August 2005 through September 2007. The 24-hour maximum discharge temperature detected in 2006 occurred on August 4 (100.2°F), and in 2007 it occurred on September 11 (101.1°F). The differences between the intake and discharge temperatures (i.e., ΔT) have also been calculated on a monthly basis for the same time period and are presented in Table 2.2-1. During this two year period, the maximum ΔT occurred in April 2006 (30.16°F) (AmerGen 2007b).

Based on monitoring from 1974 through 1990, river flow has been one of the most influential factors for both biological and water quality parameters in the Susquehanna River (Normandeau 2007). During this period, mean river flow varied widely and was influenced by snow melt, spring runoff, rain events, and drought. Based on analysis of 17 years of data for water temperature, pH, and dissolved oxygen, and 13 years for TDS (total dissolved solids), no evidence of significant influence of TMI-1 discharge on these parameters was identified. Temporal and spatial trends in these parameters appear to be related more to meteorological cycles and river flow than to TMI-1 operations (Normandeau 2007). They also reflect the influences of the varied geological, land, and water use practices throughout the Susquehanna River basin (Normandeau 2007).

Water quality in the Lower Susquehanna River Basin has improved steadily since the early 1970s. This improvement has been attributed to a reduction in mine drainage pollutants from upstream sources, improvements in sewage-treatment plants, a ban on phosphate detergents, and implementation of agricultural best-management practices. However, when looking at the entire Lower Susquehanna River Basin, nitrate (a component of total nitrogen) showed an upward trend at the uppermost (Lewisburg, Pennsylvania) monitoring station (Lindsay et al. 1998, USGS Survey Circular 1168).

In 2002, the Susquehanna River Basin Commission (SRBC) conducted a pilot study to determine appropriate methods for assessing the biology of the large rivers in the Susquehanna River Basin (Hoffman 2006). Biological and water chemistry data were collected at 25 stations during August through October 2005 on the mainstem Susquehanna River and at the mouths of the three major tributaries: the West Branch Susquehanna River, the Juniata River, and the Chemung River. Ten macroinvertebrate samples were collected at each station, using five rock baskets and five kick nets, when possible. A total of 102 rock basket samples and 125 kick net samples were collected during the survey. Six of the stations were designated moderately impaired, while 19 of the stations were designated slightly impaired. Only 79 out of 950 laboratory and field water quality data points exceeded standards or levels of tolerance for aquatic life, indicating that the Susquehanna River contains fairly good water quality (Hoffman 2006),

2.2.3 AQUATIC COMMUNITIES

As noted previously, Metropolitan Edison and GPU Nuclear monitored the ecological communities of the Susquehanna River in the vicinity of Three Mile Island from 1974 to 1982. Three Mile Island is adjacent to a small reservoir formed by York Haven and Red Hill Dams (Figure 2.1-3). This reservoir, known as York Haven Pond (Lake Frederick) extends about 3.5 miles upstream and formed the area for the aquatic studies. Normal full pool elevation of Lake Frederick is 277 feet above mean sea level and mean depth is about 9 feet (Ichthyological Associates 1983; RMC 1990; RMC 1991).

York Haven Dam was completed in 1904 and is a low head, run-of-the-river dam and hydroelectric plant. The main dam is 5,000 feet long and connects the mainland on the western side of the river to Three Mile Island; a smaller dam (Red Hill) connects Three Mile Island to the mainland on the eastern side of the river (Normandeau 2007). The York Haven hydroelectric plant generates 19-20 megawatts (MW) of power and has 13 horizontal generators that produce up to 1,000 kilowatts (KW) each and 7 vertical generators that generate between 1,200 and 1,600 KW each. Four of the vertical units use Kaplan turbines. The plant uses one of the first Kaplan turbines installed in the United States, and the plant is listed as a National Historic Engineering Landmark (ASME Undated).

At Three Mile Island, the Susquehanna River is about 7,000 feet wide and divided by islands into three channels (west, center, and east). The intake and discharge structures for TMI-1 are located along the west shore of Three Mile Island, and the intake withdraws water from the center channel (Ichthyological Associates 1983 RMC 1990; RMC 1991).

2.2.3.1 Macroinvertebrates

Between 1974 and 1982, macroinvertebrates were typically collected once in January and then twice per month starting in March; February samples in some years were not collected due to ice cover at most stations (Ichthyological Associates 1983.

A total of 66,048 specimens representing 165 taxa were collected in 1982, the largest number of taxa collected over the 1974 – 1982 period. However, total number of organisms, density, and biomass were the lowest in 1982 since 1974; which continued trends noted after the 1980 drought. The highest number of organisms was collected in 1977. Dominant taxa were *Limnodrilus hoffmeisteri* (Oligochates – aquatic worms), *Chironomus decorus* group sp. (Diptera – midges), and *Pisidium* spp. (Molluscs). *Elimia virginica*, *C. decorus* group sp. (snails), and *L. hoffmeisteri* had the greatest biomass. During the 1982 sampling, 15 species were collected for the first time (Ichthyological Associates 1983).

Monthly measures of diversity varied between upstream and downstream discharge stations during all years. However, seasonal distribution was generally the lowest in April and June at stations downstream of the discharge area and highest in March at stations upstream of the discharge. For example, in 1982 a total of 66 taxa were collected in March and represented the highest monthly total collected during the study period and may be attributed in part to drift from high spring flows (Ichthyological Associates 1983). The relative abundance, density, and biomass of *Limnodrilus hoffmeisteri* (aquatic worms) exhibited a decline over the study period and this was attributed to the 1980 drought and subsequent repopulation of drought-affected areas by *Chironomus decorus* group sp. (midges). In summary, the differences between stations were generally attributed to habitat differences and not to TMI-1 operation (Ichthyological Associates 1983). In addition, the drought of 1980 influenced the distribution and abundance of macroinvertebrates during the latter part of the study (Ichthyological Associates 1983).

The area in the vicinity of the TMI-1 discharge was continuously studied during the period from 1986 through 1990 (i.e., during a time when TMI-1 was operational after having been shut down until 1985 following an accident at Unit 2 in March 1979) (Normandeau 2007). Annual macroinvertebrate sampling during the period identified variable numbers of taxa and species diversity, with no consistent trends in spatial or temporal abundance (Normandeau 2007). None of the station abundance data for benthic macroinvertebrate communities suggested the influence of TMI-1 (Normandeau 2007). Fluctuations in environmental variables, especially river flow and water temperature, seemed to exert the predominant influence on the benthic communities in York Haven Pond (Lake Frederick) (Normandeau 2007).

2.2.3.2 Adult Fish

A number of collection methods (trapnet, seine, electrofishing) were used to characterize the adult fish community in the vicinity of Three Mile Island from 1974 through 1982. In addition, population estimates and creel surveys were conducted to further characterize the fishery and its usage by recreational fishermen (Ichthyological Associates 1983). During the study period, a total of 58 species of fish were collected representing 13 families with Ictaluridae (catfishes) and Centrarchidae (sunfishes, bass, and crappie) dominating the catches. The greatest species diversity was exhibited by the Cyprinids (carp and minnows) with 19 species (dominated by goldfish, carp, shiners, daces, and chubs) followed by Centrarchids with 9 species (primarily bass, lepomids, and crappie), Ictalurids with 5 species (dominated by channel and white catfish and bullheads), Clupeids with 4 species (blueback herring, alewife, and American and gizzard shad) and Catostomids (suckers) with 4 species (quillback, redhorse, and white and northern hogsuckers). All the remaining families were represented by three or fewer species (Ichthyological Associates 1983).

Studies of the fish community conducted in 1989 and 1990 revealed a similar species composition to those observed during 1974 through 1982 (RMC 1990; RMC 1991; Normandeau 2007). The fish community was sampled by multiple gear types. Both seine and electrofishing catches reflected the effects of natural population cycles in this section of the Susquehanna River, with no consistent pattern of temporal or spatial abundance (RMC 1990; RMC 1991; Normandeau 2007). Several representatives of the sunfish family (e.g., smallmouth bass, redbreast sunfish, rock bass) and the minnow family (spotfin shiner, spottail shiner) were consistently abundant over the study period (RMC 1990; RMC 1991; Normandeau 2007).

Trapnet Collections

Trapnet collections were taken at four stations above, adjacent to, and below the discharge from March or April through December during 1974 through 1982 (Ichthyological Associates 1979, 1983). Channel catfish, rock bass, pumpkinseed, white crappie, and black crappie dominated the collections over the study period. Channel catfish exhibited a significant decline over the study period, declining from over 7 fish per unit of effort in 1974 to less than one in 1982. Pumpkinseed showed an opposite trend with catches increasing dramatically starting in 1980 to approximately three times greater than those of earlier years. The other species (rock bass, black crappie, white crappie) showed similar trends as pumpkinseed, but their increases in 1980 – 1982 were between 1 –and 2 times those observed in 1974 – 1979. (Ichthyological Associates 1983).

The mean number of fish per trapnet collection over the 1974 – 1982 sampling period was the lowest in 1976, with catches of less than five per collection. Collections at Station 3 downstream of the discharge were the lowest among the four sampling stations. Trends between years were similar to the total catch trend; catches at all stations were greater in 1980 – 1982 than in 1974 – 1979. In general, Station 4 (approximately one mile below the discharge) exhibited the greatest catches (Ichthyological Associates 1983).

Seine Collections

Seine collections were taken at 10 stations above, adjacent to, and below the discharge from March through December during 1974 through 1982. In some years, sampling at early dates and during December was hampered by ice cover and collections were either not made or done over several days. A total of 28 species were collected in 1982, the highest number of species collected during the study period. Spotfin shiners, spottail shiners, and white suckers dominated the annual catches from 1974 through 1982 and constituted over 80 percent of the catch each year. Additional species collected were dominated by other shiners, assorted sunfishes and bass, and various darters, with an occasional walleye. As expected, there was considerable variation between years due to river flow conditions. Catches per seine haul varied from about 30 to over 124; however, the range in yearly catches was relatively stable (Ichthyological Associates 1983). Spotfin shiners exhibited a significant increase beginning in 1980, and by 1981 and 1982 catches were over 10 times those of 1974. Spottail shiners exhibited a significant decline over the same period, but not as dramatic (Ichthyological Associates 1983). The greatest diversity (number of species per seine haul) occurred at a station on the western side of the river, while all other stations exhibited lower, but more uniform, catches over the study period (Ichthyological Associates 1983).

Electrofishing

Electrofishing (boat-mounted) was used to sample 12 near-shore areas above, adjacent to, and below the discharge from March or April through December during 1976 through 1982. In some years, March sampling was not conducted due to ice cover. During the sampling period; the number of species collected ranged from 25 to 31, with Centrarchids dominating the catch each year. Five species -- the rock bass, redbreast sunfish, pumpkinseed, bluegill, and smallmouth bass -- accounted for over 60 percent of the catch each year. In general, pumpkinseed sunfish were the most abundant each year. Spring and fall sampling periods exhibited the largest catches, while summer catches were the smallest. Differences in species composition and abundance among the sampling stations, sampling periods, and years (1976 – 1982) were attributed to habitat differences, changes in river flow and water temperature, and natural fluctuations inherent in fish populations rather than TMI-1 operations (Ichthyological Associates 1983).

Electrofishing studies conducted in 1989 and 1990 revealed similar results to those conducted during 1976 – 1982 (RMC 1990; RMC 1991). The small differences in catch per unit of effort at stations above, near, and adjacent to the TMI-1 discharge revealed no evidence to suggest that the operation of TMI-1 had any influence on the distribution of fish populations in York Haven Pond (Lake Frederick) (RMC 1990; RMC 1991).

Creel Surveys

Roving creel surveys were conducted for over 16 continuous years on the Susquehanna River in the vicinity of Three Mile Island from January through December during 1974 through 1990 (Ichthyological Associates 1983; RMC 1990; RMC 1991, Normandeau, 2007). In 1982, an estimated 19,914 anglers caught 45,603 fish, kept 12,546 fish, and fished for 34,053 hours. The largest number of anglers, fish caught, fish kept, and hours fished in all areas combined were reported in May. Channel catfish, rock bass, smallmouth bass, and walleye composed over 80 percent of the total catch. The smallmouth bass was the species most often caught and kept by anglers during April through November. Over 70 percent of the anglers interviewed were residents of York or Dauphin Counties (Ichthyological Associates 1983).

In 1990, a total of 39,953 angler hours were expended resulting in a total catch of 37,955 fish with the anglers keeping 7,158 fish (Normandeau 2007). Sport fishing catches were dominated by smallmouth bass, channel catfish, rock bass, and walleye. Catch and harvest fluctuated as fish populations responded to angler preferences and variable year class success (Normandeau 2007). A large number of anglers throughout the 16 survey years indicated that they released or gave away all, or at least a portion of their catch, reflecting an interest in fishing primarily for recreation (Normandeau 2007).

The impact of the 1979 accident at TMI-2 on recreational fishing was assessed in subsequent years by asking whether anglers used their catch differently than they did in prior years. During 1980 (the year immediately after accident), 7.6 percent of the anglers interviewed indicated that they had changed their use of catch due to the accident. The proportion of anglers expressing a change in catch usage steadily declined during the 1980s and no anglers reported changing their catch usage in either 1989 or 1990 (RMC 1990; RMC 1991). As of 1990, most anglers reported that they eat at least a portion of their catch (RMC, 1991).

There are no updated creel survey data for the Lake Frederick area of the Susquehanna River. However, in 2007 a creel survey overseen by the Pennsylvania Fish and Boat Commission is underway (April through October 2007) that will explore fishing use and anglers' experience on 130 miles of the Susquehanna and Juniata Rivers from Sunbury to the Holtwood Dam near the Maryland border (Frederick 2007).

Recreational Fishing

The Susquehanna River in the area of Three Mile Island provides some of the best smallmouth bass fishing in the eastern U.S. (Nicewonger 2002). The stretch of the river from Harrisburg to Holtwood Dam, in particular, has benefited from the 1990 implementation of special fishing regulations designed to enhance the smallmouth bass fishery (Jaworoski Undated 1). Since that time, the special regulations have become more protective of this fishery and now apply to nearly 90 miles of the Susquehanna. In winter months, anglers are allowed to keep two fish per day, 18-inch minimum. During the spring spawning period, Mid-April through mid-June, all bass must be released. From mid-June through October 1, anglers may keep four fish per day, 15-inch minimum. These regulations have increased the number of smallmouth bass in this stretch of the river and increased the average size of these fish (Jaworoski Undated1). Professional fishing guides tout the area's excellent smallmouth bass habitat and the unique experience of fishing "in the shadow" of the Three Mile Island cooling towers (McNally 1997; Backwoods Angler 2006).

Aside from smallmouth bass fishing, more placid sections of the Susquehanna River in the vicinity of Three Mile Island offer excellent fishing for sunfish (rock bass, crappie, pumpkinseed, and redbreast sunfish) and channel catfish (Jaworoski Undated2). These waters also provide outstanding fishing for muskie and walleye (Hartman 2000).

American Shad and Lower Susquehanna River Basin

The American Shad is an important anadromous fish that spawns in the Susquehanna River. Prior to 2000, access to the upper reaches of the river above York Haven Dam was limited to physical transport (Normandeau 2007) due to the absence of fish passage facilities. Between 1904 and 1930, four hydroelectric dams were built on the lower Susquehanna River: York Haven (1904), Holtwood (1910), Conowingo (1928), and Safe Harbor (1930). (Pennsylvania Fish and Boat Commission Undated).

When the Conowingo Dam was built, state and federal fishery authorities conceded that development of effective fish passageways at high dams was not practical and the Susquehanna River shad resource was lost (Pennsylvania Fish and Boat Commission Undated). However, by the 1950s, fish passage technology had improved and studies were undertaken to assess the possibility of restoring shad runs to the Susquehanna River. These state- and utility-sponsored efforts included determining the ability of shad to move upstream and reproduce, determining the engineering and biological feasibility for fish passage at dams, and evaluating the suitability of the river to support migratory fishes. Results of the fish passage engineering and habitat suitability studies were favorable (Pennsylvania Fish and Boat Commission Undated).

Pursuant to Federal Energy Regulatory Commission (FERC) relicensing efforts for York Haven Dam, the York Haven Power Company agreed to the design and construction of fish passage facilities at York Haven. In 2000, York Haven Power Company completed a 500,000-fish-capacity fish ladder at Three Mile Island east channel dam (Red Hill Dam) at a cost of about $9 million (Pennsylvania Fish and Boat Commission Undated). The York Haven fishway consists of a 67-foot-wide notch in the 11-foot-high east channel dam (Red Hill Dam). It allows downstream passage of fish if the Susquehanna River is low during the annual migration period from April 1 to the end of June. The flow of water through the notch is controlled by a new upstream permanent structure that has two 20-foot wide gated openings. The water flowing through the notch also provides attraction flow to help upstream migrating fish locate the staggered pool, vertical slot fish ladder, which is also part of the fishway. The fish ladder will allow fish to migrate upstream during periods of low river flow. The fishway was hydraulically designed to also allow upstream passage through the dam notch and 20-foot gates during higher river flows as well. The York Haven fishway became operational on April 1, 2000 (Kleinschmidt Undated).

Completion of this fish passage facility meant that American Shad as well as other migratory fish could ascend the Susquehanna River as far as Binghamton, New York, a distance of approximately 435 miles (Pennsylvania Fish and Boat Commission, Undated).

Over the period 2000 through 2006, a total of 28,870 American Shad were passed over the York Haven fishway (Table 2.2-2). The number ranged from 219 (2004) to 16,200 (2001) (Pennsylvania Fish and Boat Commission, Undated). In addition, over 12,000 smallmouth bass, 42,000 walleye, and 480,000 gizzard shad were successfully passed at the York Haven fishway.

The fish studies described in Section 2.2.3 were conducted in the vicinity of Three Mile Island over three distinct periods: (1) before TMI-1 and TMI-2 began operating, (2) during peak operation with two reactors, and (3) during operation with only TMI-1. Taken as a whole, the studies show that the Susquehanna River in the vicinity of Three Mile Island supports a diverse assemblage of coolwater and warmwater fishes. Neither York Haven Dam or the operation of TMI-1 impede the passage of migratory fish. There is no indication that pollution-tolerant species or groups are predominant, or that sensitive or pollution-intolerant species are rare or absent. Water quality improvement in the 1970s and 1980s brought fishermen back to the river in increasing numbers as evidenced by creel surveys.

2.3 GROUNDWATER RESOURCES

2.3.1 WATER-BEARING UNITS

TMI-1 is located on Three Mile Island in the Susquehanna River in a segment of the river where the incised river channel is wider than upstream and downstream segments.

Water-bearing units (aquifers) in the vicinity include (1) a unit under water table conditions located in the surficial alluvial, and glacial deposited materials (glacial material directly overlies the bedrock) that compose the island and (2) the underlying sedimentary sequence under artesian conditions known as the Gettysburg shale, which is part of the Newark group of Triassic Age. The first water-bearing unit (i.e., the unit under water table conditions) is composed of silts, sands, and gravels, with varying amounts of clay. The surficial deposits in this unit vary in thickness from 7 to 19 feet, and the glacial material varies from 12 to 21 feet. This unit, although capable of producing water, is not considered a major aquifer in the area. Groundwater conditions in the alluvial material of the first unit are controlled by the Susquehanna River. The water table reaches its maximum elevation at the highest point in the center of the island, then slopes toward both the eastern and western shores with a gradient of less than one percent. The groundwater flow eventually enters the river, which acts as a natural boundary. River flow to the rock of the Gettysburg shale (i.e., the second water bearing unit mentioned above) on either bank of the river is highly unlikely due to the lower flow characteristics of the Gettysburg shale when compared to those of the alluvial materials and the higher groundwater levels on either shore with hydraulic gradients toward the river. River flow to the Gettysburg shale might occur, however, if very heavy pumping were to occur on shore because heavy pumping on shore would create induced infiltration (AmerGen 2006a).

The second water-bearing unit mentioned above (i.e., the Gettysburg shale) is the primary aquifer in the vicinity of Three Mile Island. In this unit, groundwater is found under artesian conditions in the bedrock. Groundwater in the bedrock is present along bedding plane separations, closely spaced joints, and fractures. Hydraulic conductivity values vary from 2,126 feet/year to 4,208 feet/year. Maximum drawdown occurs parallel to the bedding strike in response to pumping (McLaren/Hart 1998a). Bedrock has been encountered at depths of 19 to 28 feet throughout Three Mile Island during drilling operations. At the Three Mile Island Nuclear Station, bedrock dips uniformly to the northwest at approximately 37 degrees. Two prominent bedrock joints exist on the island. One dips approximately 72 degrees to near vertical and strikes approximately due north. The other dips 50 to 60 degrees southwest and has a northwest strike (McLaren/Hart 1998a).

2.3.2 WATER SUPPLY WELLS

A search of the Pennsylvania Groundwater Information System was performed to locate off-site wells within 1 mile of the plant site. This search indicated there are 47 water supply wells not associated with the Three Mile Island Nuclear Station within the specified 1-mile radius. Only 1 of these was designated as a public drinking water supply well. The rest are primarily used for domestic purposes (Conestoga-Rovers 2006).

There are seven water supply wells associated with the Three Mile Island Nuclear Station. Five are located on Three Mile Island within the plant site (Figure 2.3-1). The other two are located off the island at the Visitors Center and the Training Center/Simulator Building (Figure 3.1-1), as is further described below. Two of the five wells on Three Mile Island supply the on-site, non-community, public water system. They are called the Operations Support Facility/North Office Building (OSF) well and the Building 48 (48S) well. They were installed to depths of 775 feet and 996 feet, respectively, and have maximum design yields of 40 gallons per minute (gpm) and 30 gpm, respectively. If it is not needed to supply drinking water, the OSF well also may be used to augment the supply of service water, which is otherwise provided by site production wells A, B, and C [Susquehanna River Basin Commission (SRBC) Well numbers 1, 2, and 3, respectively]. These three wells supply industrial makeup water (including fire service, makeup to the demineralized water system, bearing lubrication for the screen house pumps, and service for other buildings and equipment) (McLaren/Hart 1998b) and were installed to depths of 400 feet, 500 feet, and 400 feet, respectively. Wells A, B, and C are permitted to pump a total of 225,000 gallons per day (gpd) (156 gpm) of groundwater (SRBC 1999).

As previously mentioned, two of the seven water supply wells associated with the Three Mile Island Nuclear Station are located off the island at the Visitors Center and the Training Center/Simulator Building. The well that supplies potable water to the Visitors Center was installed to a depth of 121 feet and has a maximum design yield of about 10 gpm. The well that provides potable water to the Training Center/Simulator Building was installed to a depth of 100 feet and has a maximum design yield of 30 gpm.

For the period from 2003 to 2005, groundwater production from the seven water supply wells associated with the Three Mile Island Nuclear Station averaged between approximately 95 to 115 gpm (AmerGen 2004, AmerGen 2005, AmerGen 2006a).

2.3.3 GROUNDWATER MONITORING

Since 1980, numerous groundwater monitoring wells have been installed at the Three Mile Island Nuclear Station for various monitoring or investigative programs. Such wells have been sampled at varying frequencies and for a variety of parameters. Over time, some wells have been closed. Historical knowledge and data related to Station operations and radionuclide analyses of groundwater samples from such wells indicate tritium to be the radionuclide most often detected above background concentrations in the groundwater (Conestoga-Rovers 2006). Tritium is a radionuclide that decays by emitting a low-energy beta particle that cannot penetrate deeply into tissue or travel far in air. It is created in the environment from naturally occurring processes both cosmic and subterranean, as well as from anthropogenic (i.e., man-made) sources. The background concentration for tritium in groundwater at the Three Mile Island Nuclear Station has been estimated to be approximately 200 pCi/L or lower (Conestoga-Rovers 2006).

In 2006, Exelon conducted a comprehensive initiative to evaluate the radiological impacts of operations on groundwater and surface water in the vicinities surrounding all Exelon-owned nuclear power stations, including TMI-1. As a result of this initiative, the groundwater monitoring network at the Three Mile Island Nuclear Station was expanded, and 31 new permanent, on-site groundwater monitoring wells were installed. Also, the 2006 groundwater monitoring effort at the Three Mile Island Nuclear Station occurred in two parallel phases. Phase 1, which occurred during May, implemented the Exelon initiative at the Station. Phase 2 continued the groundwater monitoring program that had been ongoing at the Station for over 20 years.

During the May 2006, Phase 1 groundwater monitoring effort, 58 on-site wells were sampled for tritium, strontium-90, and gamma emitting radionuclides. Tritium was not detected at concentrations greater than the EPA drinking water standard of 20,000 pCi/L. Tritium was detected at concentrations greater than background. Such concentrations ranged from 223 ± 114 pCi/L to 13,500 ± 1,390 pCi/L. (Conestoga-Rovers 2006)

During the 2006 Phase 2 groundwater monitoring effort, samples were collected from 76 locations, two of which were off-site drinking water wells, and many of which were also sampled as part of Phase 1. Sampling was conducted from January through December 2006. No detectable concentration of tritium was found in the off-site drinking water wells. Tritium was not detected in any of the other groundwater samples at concentrations greater than the EPA drinking water standard of 20,000 pCi/L. Tritium was detected at concentrations greater than background in 46 on-site wells. Such concentrations ranged from 201 ± 111 pCi/L to 19,200 ± 1960 pCi/L. (AmerGen 2007a)

In 2007, AmerGen implemented a revised long-term groundwater monitoring effort referred to as the Radiological Groundwater Protection Program (RGPP) at TMI-1, replacing the previous groundwater monitoring program (AmerGen 2007a). A primary purpose of the RGPP is to provide timely detection and effective response to radiological releases to groundwater (Exelon 2006b). A total of 59 on-site groundwater wells, which are shown on Figure 2.3-1, are included in the Three Mile Island Nuclear Station RGPP (Exelon 2007). These wells, 5 of which are the 5 on-site water supply wells described in section 2.3.2, are sampled at various frequencies for tritium, strontium-90, and gamma emitting radionuclides.

Under the RGPP, groundwater sampling conducted during 2007 has been regularly compared with the 2006 Phase 1 results, which have been designated as the Baseline Monitoring Round for the TMI-1 RGPP. Such comparison serves to establish trends, identify potentially contaminated systems, and verify that radiological protection of groundwater is maintained (Exelon 2006b). This process identified significantly increased tritium concentrations in several wells during the period from May through July 2007. During this period, six samples from two monitoring wells exceeded the EPA drinking water standard of 20,000 pCi/L, with the highest being 29,600 pCi/L in July. By then, however, Station personnel had identified the source of the leak, isolated and removed the leaking piping from service, and repaired the leak. Subsequently, tritium concentrations decreased in all wells to levels far below the EPA drinking water standard, which demonstrated the success of the repair, and the utility of the RGPP for protecting the quality of groundwater.

In January 2007, Conestoga-Rovers & Associates (Conestoga-Rovers) completed calculations (using results from the 2006 Phase 1 investigation) to determine the estimated mass flux of tritiated groundwater to the Susquehanna River. The results were reconfirmed following repair of the tritium leak in June 2007 (Conestoga-Rovers 2007). The following matrix summarizes the estimated rate of tritium migration with and without pumping of the on-site production wells A, B, and C and with and without background.

	Total Mass Flux With Background (Ci/yr)	Background Contribution (Ci/yr)	Total Mass Flux Without Background (Ci/yr)
No pumping	0.32	0.09	0.23
Tritium Captured by Pumping	0.20	0.013	0.18
With Pumping	0.12	0.074	0.05

Source: Conestoga-Rovers (2006)

Based on these results and conditions at the Station with respect to pumping of the production wells, Conestoga-Rovers concluded that the cumulative migration of tritium in groundwater to the river was negligible compared to the Station's regulated tritium releases to the river under its Radiological Effluents Control Program, which is inspected by and reported to the NRC. Furthermore, even without pumping of the three production wells, the amount of tritium entering the river in groundwater was estimated to be minimal.

2.4 CRITICAL AND IMPORTANT TERRESTRIAL HABITATS

Three Mile Island covers approximately 370 acres, of which about 200 are occupied by the TMI-1 and TMI-2 facilities (Figure 3.1-2). AmerGen owns the entire island except certain TMI-2 facilities. AmerGen also owns all or a portion of some of the smaller islands in the vicinity of Three Mile Island and a portion of the eastern bank of the Susquehanna River. TMI-1 is surrounded by fencing and contains few areas that have not been developed or previously disturbed. The undeveloped land on the island is found south of the TMI-1 and TMI-2 facilities (Figure 3.1-2). The majority of this undeveloped land lies under the ten- year flood level and is subject to seasonal variations in water level. The southern part of the island contains a wetland that was formed when borrow pits created during construction of a flood dike system, which surrounds the TMI-1 and TMI-2 facilities, filled with water. The southern portion of the island also contains fallow field areas that are surrounded by a woodland buffer. Riparian buffer areas are intact around the perimeter of the entire island although forested riparian areas are isolated to the southern part of the island (WHC 2005).

The Susquehanna River is an important source of fresh water and nutrients that flow into the Chesapeake Bay. The Chesapeake Bay is vital to migratory waterfowl on the eastern flyway (DU 2006). The islands in the Susquehanna River are important resting stops for migratory waterfowl and the borrow pits on Three Mile Island provide nesting and foraging habitat. The peregrine falcon and osprey are known to nest on the island. The island has also been identified as a potential nesting site for bald eagles although none are known to nest there now (WHC 2005). These particular three birds of interest are discussed further in Section 2.5, Threatened and Endangered Species.

Three Mile Island is located within the Central Appalachian Broadleaf Forest – Coniferous Forest – Meadow Province (WHC 2005). Local differences in vegetation types and densities in this Province are a function of elevation and the soil fertility. Primarily in the southern and undeveloped portions of the island, open field habitat is dominated by foxtail grasses bordered by tree and shrub buffers. Plant species in these buffer areas include sycamore, sweetgum, blackberry, basswood, and locust trees. The riparian forest areas on Three Mile Island contain silver maple, alder, birch, and sycamore (WHC 2005). These plants provide cover of varying degrees and a direct source of food for various reptiles, birds, and mammals. Mammals commonly identified in the area include white-tailed deer, striped skunk, raccoon, red fox, and grey squirrel.

Transmission lines associated with TMI-1 extend into Dauphin, Lancaster, and York Counties. Four 230-kilovolt (kV) transmission lines associated with TMI-1 cross these counties and terminate 0.7 to 4.1 miles from the plant (Figure 3.1-2). The primary land use type crossed by the transmission lines is agricultural, but the lines also cross residential, urban, and forested areas. Land planning in Dauphin, Lancaster, and York Counties emphasizes preservation of agricultural land use and restriction of development to areas already impacted. These counties also emphasize the identification and protection of natural areas and incorporate this theme into their future land use policies (York County 2006; Dauphin County 2007; Lancaster County 2006). Plant and animal species in the areas near the transmission lines are represented by those found on Three Mile Island.

2.5 THREATENED AND ENDANGERED SPECIES

Animal and plant species that are state- or federally-listed as endangered or threatened and recorded in counties within which TMI-1 and its associated transmission lines are located are listed in Table 2.5-1. Counties crossed by the transmission lines are Dauphin (the location of TMI-1), Lancaster, and York (Figure 3.1-2). The total length of all four lines are less than 8 miles. The species included in Table 2.5-1 are those that meet at least one of the following conditions:

- Records maintained by the U.S. Fish and Wildlife Service (FWS) indicate that the species is known to occur in Dauphin, Lancaster or York counties, and the species is federally-listed as endangered, threatened, proposed for federal listing, or is a candidate for federal listing (FWS 2006).

- Records maintained by the Pennsylvania Natural Heritage Program (PNHP) indicate that the species is known to occur in Dauphin, Lancaster or York counties, and the species is state-listed as endangered or threatened (PNHP 2006 and 2007).

- The species has been observed in the vicinity of TMI-1 by Wildlife Habitat Council biologists or TMI-1 employees (WHC 2005), and is state- or federally-listed.

Three species in Table 2.5-1 are federally-listed as endangered or threatened. Bog turtles (*Clemmys muhlenbergii*), federally-listed as threatened, occur in York County. Populations of the Northeastern bulrush (*Scirpus ancistrochaetus*), federally-listed as endangered, is known to be present in Dauphin County (PNHP 2006). The Dwarf wedgemussel (*Alasmidonta heterodon*), federally-listed as endangered, is known to occur in Lancaster County (PNHP 2007). AmerGen is not aware of any occurrences of the bog turtle, Northeastern bulrush, or Dwarf wedgemussel on Three Mile Island or along the transmission lines associated with TMI-1. Bald eagles; (*Haliaeetus leucocephalus*), have recently been removed (August 2007) from the *Endangered Species Act* list of federally protected species; however, they remain protected by two other federal laws, The Bald and Golden Eagle Protection Act and the Migratory Bird Treaty Act (BLM 2007). Bald eagles have become relatively common along the Susquehanna River and are known to occur in Dauphin, Lancaster, and York counties. Occasionally, they have been observed on Three Mile Island, but no nests are known to be located there. There is a nest located approximately 20 miles south, near the Holtwood Dam.

The Susquehanna River and the associated riparian and wetland areas in the vicinity of Three Mile Island are used by many migratory and resident bird species (NRC 1989). Osprey (*Pandion haliaetus*) and peregrine falcon (*Falco peregrinus*) nests are known to occur on the TMI-1 property. Ospreys have nested on the meteorological tower every year since 2004. A 55-foot nesting platform was erected near the tower, but the ospreys have not used it. Peregrine falcons have nested on the TMI-1 Reactor Building every year since 2002. A nest box designed for peregrine falcons was placed on the TMI-2 Reactor Building in 2002, but the birds have not used it (PADEP 2007). AmerGen cooperates with the Pennsylvania Department of Environmental Protection (PADEP) in regularly monitoring the osprey and peregrine falcon nests on the TMI-1 property.

Other state-listed bird species identified in counties crossed by the transmission lines include the upland sandpiper (*Bartramia longicauda*), American bittern (*Botaurus lentiginosus*), great egret (*Casmerodius alba*), sedge wren (*Cistothorus platensis*), bald eagle (*Haliaeetus leucocephalus*), yellow-crowned night heron (*Nyctanassa violacea*), black-crowned night heron (*Nycticorax nycticorax*) and king rail (*Rallus elegans*). Two state-listed mammals occur in counties crossed by TMI-1 transmission lines. The Allegheny woodrat (*Neotoma magister*) has been identified in Dauphin County and the least shrew (*Cryptotis parva*) has been identified in York County. Two state-listed reptiles occur in counties crossed by TMI-1 transmission lines. The redbelly turtle (*Pseudemys rubriventris*) has been identified in York County and the rough green snake (*Opheodrys aestivus*) has been identified in Lancaster County. One state-listed fish, the black bullhead (*Ameiurus melas*), has been recorded in Dauphin County (PNHP 2006 and PNHP 2007). The American holly (*Ilex opaca*), state-listed as threatened, has been recorded on TMI-1 property (WHC 2005). Other plants that are state-listed as threatened or endangered and known to occur in Dauphin, Lancaster, and York counties are shown in Table 2.5-1. With the exception of the bald eagle, peregrine falcon, osprey, and American holly, AmerGen is not aware of occurrences of species listed in Table 2.5-1 on Three Mile Island or along transmission lines associated with TMI-1.

Appendix C includes copies of AmerGen correspondence with FWS, the Pennsylvania Game Commission, Pennsylvania Department of Conservation and Natural Resources, and the Pennsylvania Fish and Boat Commission.

2.6 DEMOGRAPHY

2.6.1 REGIONAL DEMOGRAPHY

The Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) presents a population characterization method that is based on two factors: "sparseness" and "proximity" (NRC 1996). "Sparseness" measures population density and city size within 20 miles of a site and categorizes the demographic information as follows:

Demographic Categories Based on Sparseness

		Category
Most sparse	1.	Less than 40 persons per square mile and no community with 25,000 or more persons within 20 miles
	2.	40 to 60 persons per square mile and no community with 25,000 or more persons within 20 miles
	3.	60 to 120 persons per square mile or less than 60 persons per square mile with at least one community with 25,000 or more persons within 20 miles
Least sparse	4.	Greater than or equal to 120 persons per square mile within 20 miles
Source: NRC 1996		

"Proximity" measures population density and city size within 50 miles and categorizes the demographic information as follows:

Demographic Categories Based on Proximity

		Category
Not in close proximity	1.	No city with 100,000 or more persons and less than 50 persons per square mile within 50 miles
	2.	No city with 100,000 or more persons and between 50 and 190 persons per square mile within 50 miles
	3.	One or more cities with 100,000 or more persons and less than 190 persons per square mile within 50 miles
In close proximity	4.	Greater than or equal to 190 persons per square mile within 50 miles
Source: NRC 1996		

The GEIS then uses the following matrix to rank the population category as low, medium, or high.

GEIS Sparseness and Proximity Matrix

		Proximity			
		1	**2**	**3**	**4**
Sparseness	**1**	**1.1**	**1.2**	**1.3**	**1.4**
	2	**2.1**	**2.2**	**2.3**	**2.4**
	3	**3.1**	**3.2**	**3.3**	**3.4**
	4	**4.1**	**4.2**	**4.3**	**4.4**

Low Population Area	Medium Population Area	High Population Area

Source: NRC 1996

AmerGen used 2000 census data from the U.S. Census Bureau (USCB) with geographic information system software (ArcGIS®) to determine most demographic characteristics in the TMI-1 vicinity. The calculations determined that 787,806 people live within 20 miles of TMI-1, producing a population density of 627 persons per square mile. Applying the GEIS sparseness measures results in the least sparse category, Category 4 (greater than or equal to 120 persons per square mile within 20 miles).

To calculate the proximity measure, AmerGen determined that 2,546,479 people live within 50 miles of TMI-1, which equates to a population density of 325 persons per square mile. Applying the GEIS proximity measures, the TMI-1 region is classified as Category 4 (greater than or equal to 190 persons per square mile within 50 miles). Therefore, according to the GEIS sparseness and proximity matrix, the TMI-1 region ranks of sparseness, Category 4, and proximity, Category 4, result in the conclusion that TMI-1 is located in a high population area.

All or parts of 22 counties and a number of Metropolitan Statistical Areas (MSAs) are located within 50 miles of TMI-1 (Figure 2.1-1). The MSAs nearest TMI-1 are (1) Harrisburg-Carlisle, PA, (2) Lancaster, PA, (3) Reading, PA, and (4) York-Hanover, PA, (USCB 2003). The nearest major city is Harrisburg, Pennsylvania (12 miles northwest), with a 2000 population of 48,950 (USCB 2000a). Additional nearby population centers are York (15 miles south) and Lancaster (25 miles southeast) where the 2000 populations were 40,862 and 56,348, respectively. The municipality nearest TMI-1 is the Goldsboro Borough (1.25 miles west, across the Susquehanna River) with a 2000 population of 939 (USCB 2000b).

From 1990 to 2000, the population of the Harrisburg-Carlisle, PA MSA increased from 474,242 to 509,074, an increase of 7.3 percent. The population of the Lancaster, PA MSA increased from 422,822 to 470,658, an increase of 11.3 percent. The population of the York-Hanover, PA MSA increased from 339,574 to 381,751, an increase of 12.4 percent. The population of the Reading, PA MSA increased from 336,523 to 373,638, an increase of 11.0 percent (USCB 2003).

Because approximately 71 percent of employees at TMI-1 reside in Dauphin and Lancaster Counties, they are the counties with the greatest potential to be socioeconomically affected by license renewal at TMI-1 (Table 2.6-1). Table 2.6-2 shows population counts and growth rates for these two counties. Values for the Commonwealth of Pennsylvania are provided for comparison. The table is based on USCB data for 1980, 1990, and 2000.

Over the last two decades, Pennsylvania, as well as Dauphin and Lancaster Counties, has experienced positive growth. From 1980 to 1990, Dauphin and Lancaster Counties' growth rates outpaced the Commonwealth of Pennsylvania. From 1990 to 2000, the two counties' population growth slowed, yet remained positive. Both counties continued to outpace Pennsylvania, which experienced an increase in growth. Overall, Lancaster County has experienced the highest percentage of growth.

2.6.2 MINORITY & LOW-INCOME POPULATIONS

The Nuclear Regulatory Commission (NRC) performed environmental justice analyses for previous license renewal applications and concluded that a 50-mile radius (Figure 2.1-1) could reasonably be expected to contain potential environmental impact sites and that the state was appropriate as the geographic area for comparative analysis. AmerGen has adopted this approach for identifying the minority and low-income populations that could be affected by TMI-1 operations.

AmerGen used 2000 census data from the USCB with geographic information system software (ArcGIS®) to determine the minority characteristics by block group. AmerGen included any block group with part of its area within 50 miles of TMI-1. The 50-mile radius includes 1,931 block groups (Table 2.6-3).

2.6.2.1 Minority Populations

The NRC Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues defines a "minority" population as: American Indian or Alaskan Native; Asian; Native Hawaiian or other Pacific Islander; Black Races, and Hispanic Ethnicity (NRC 2001). Additionally, NRC's guidance requires that (1) all other single minorities are to be treated as one population and analyzed, (2) multi-racial populations are to be analyzed, and (3) the aggregate of all minority populations are to be treated as one population and analyzed. The guidance indicates that a minority population exists if either of the following two conditions exists:

- The minority population in the census block group or environmental impact site exceeds 50 percent.
- The minority population percentage of the environmental impact area is significantly greater (typically at least 20 percentage points) than the minority population percentage in the geographic area chosen for comparative analysis.

For each of the 1,931 block groups within the 50-mile radius, AmerGen calculated the percent of the block group's population represented by each minority (Table 2.6-3). If any block group minority percentage exceeded 50 percent, then the block group was identified as containing a minority population. AmerGen selected the entire Commonwealth of Pennsylvania as the geographic area for comparative analysis for block groups located within the borders of Pennsylvania, and calculated the percentages of each minority category in the Commonwealth. AmerGen selected the entire State of Maryland as the geographic area for comparative analysis for block groups located within the borders of

Maryland, and calculated the percentages of each minority category in the State. If any block group percentage exceeded the corresponding State percentage by more than 20 percent, then a minority population was determined to exist.

Census data for Pennsylvania characterizes 0.15 percent of the population as American Indian or Alaskan Native; 1.79 percent Asian; 0.03 percent Native Hawaiian or other Pacific Islander; 9.97 percent Black races; 1.53 percent all other single minorities; 1.16 percent multi-racial; 14.63 percent aggregate of minority races; and 3.21 percent Hispanic ethnicity. Census data for Maryland characterizes 0.29 percent of the population as American Indian or Alaskan Native; 3.98 percent Asian; 0.04 percent Native Hawaiian or other Pacific Islander; 27.89 percent Black races; 1.80 percent all other single minorities; 1.96 percent multi-racial; 35.97 percent aggregate of minority races; and 4.30 percent Hispanic ethnicity.

Table 2.6-3 presents the numbers of block groups in each county in the 50-mile radius that exceed the threshold for minority populations. Figures 2.6-1 through 2.6-5 displays the minority block groups within the 50-mile radius.

Seventy-eight census block groups within the 50-mile radius have Black races populations that exceed the state average by 20 percent or more. Of those 78 block groups, 38 have Black races populations of 50 percent or more.

Fifty-six census block groups within the 50-mile radius have All Other Single Minority populations that exceed the state average by 20 percent or more. Of those 56 block groups, 2 have All Other Single Minority populations of 50 percent or more.

One hundred and fifty-five of the Pennsylvania census block groups that lie within the 50-mile radius have Aggregate Minority populations that exceed the Pennsylvania average by 20 percent or more. Of those 155 block groups, 100 have Aggregate Minority populations of 50 percent or more. None of the Maryland census block groups that lie within the 50-mile radius have Aggregate Minority populations that exceed the Maryland average by 20 percent or more. One block group has Aggregate Minority populations of 50 percent or more (see note at the bottom of Table 2.6-3).

One hundred and five census block groups within the 50-mile radius have Hispanic Ethnicity populations that exceed the average in their state by 20 percent or more. Of those 105 block groups, 33 have Hispanic Ethnicity populations of 50 percent or more.

2.6.2.2 Low-Income Populations

NRC guidance defines low-income population based on statistical poverty thresholds (NRC 2001) if either of the following two conditions are met:

- The low-income population in the census block group or the environmental impact site exceeds 50 percent.
- The percentage of households below the poverty level in an environmental impact area is significantly greater (typically at least 20 percentage points) than the low-income population percentage in the geographic area chosen for comparative analysis.

AmerGen divided USCB low-income households in each census block group by the total households for that block group to obtain the percentage of low-income households per block group. Using the Commonwealth of Pennsylvania as the geographical area chosen for comparative analysis for block groups within the borders of Pennsylvania, AmerGen determined that 10.99 percent of Pennsylvania households are low-income. Using the State of

Maryland as the geographical area chosen for comparative analysis for block groups within the borders of Maryland, AmerGen determined that 8.32 percent of Maryland households are low-income. Table 2.6-3 identifies the low-income block groups in the region of interest, based on NRC's two criteria. Figure 2.6-5 displays the low-income block groups.

Sixty-six of the 1,931 census block groups within the 50-mile radius have low-income households that exceed their state average by 20 percent or more. Of those 66 block groups, 14 have 50 percent or more low-income households.

2.7 TAXES

In the past, the owners of TMI-1 paid real estate taxes to the Commonwealth of Pennsylvania on their generating, transmission, and distribution facilities. Under authority of the Pennsylvania Utility Realty Tax Act (PURTA), real estate taxes collected from all utilities (water, telephone, electric, and railroads) were redistributed to the taxing jurisdictions within the Commonwealth. In Pennsylvania, these jurisdictions included all counties, cities, townships, boroughs, and school districts. The distribution of PURTA funds was determined by formula, and was not necessarily based on the individual utility's effect on a particular government entity.

In 1996, Governor Tom Ridge signed into law the Electricity Generation Customer Choice and Competition Act, which allows consumers to choose among competitive generation suppliers. As a result of utility restructuring, Act 4 of 1999 provided for a revision of the tax base assessment methodology for utilities from the depreciated book value to the market value of utility property. Additionally, as of 2000, TMI-1 was required to begin paying real estate taxes directly to local taxing jurisdictions, ceasing payments to the Commonwealth's PURTA fund. Periodically, the owner of TMI-1 negotiates with its local taxing jurisdictions regarding market value assessments of the station and the resultant taxes that will be paid. AmerGen conducted the last negotiation in 2005. AmerGen and the local taxing jurisdictions agreed that the assessed value of TMI-1 would be $20,000,000 in 2005 and $18,250,000 each year from 2006 until 2008. The assessed value for years beginning with 2009 will be negotiated at appropriate times, in accordance with applicable law.

Currently, AmerGen pays annual property taxes to Dauphin County, Londonderry Township, and the Lower Dauphin County School District, so the focus of this analysis will be on those taxing entities.

From 2000 through 2005, Dauphin County collected between $58 and $90 million annually in property tax revenues (see Table 2.7-1). Dauphin County property tax revenues fund, among other things, county operations, the judicial system, public safety, public works, cultural and recreational programs, human services, and conservation and development programs. Table 2.7-1 details the property tax payments made by the owners of TMI-1 for the same years. From 2000 to 2005, TMI-1 property tax payments have represented 0.2 to 0.3 percent of Dauphin County's total property tax revenues.

From 2000 through 2005, Londonderry Township collected between $4 and $6.3 million annually in property tax revenues (see Table 2.7-1). Londonderry Township property tax revenues fund county operations (which include libraries, hospitals, roads, etc.), school districts, and fire departments. Table 2.7-1 details the property tax payments made by the owners of TMI-1 for the same years. From 2000 to 2005, TMI-1 property tax payments have represented 0.3 to 0.7 percent of Londonderry Township's total property tax revenues.

From 2000 through 2005, the Lower Dauphin School District (LDSD) collected between $13 and $21 million annually in property tax revenues (see Table 2.7-1). Table 2.7-1 details the property tax payments made by the owners of TMI-1 for the same years. From 2000 to 2005, TMI-1 property tax payments have represented 1.7 to 2.9 percent of LDSD total tax revenues.

2.8 LAND USE PLANNING

This section focuses on Dauphin and Lancaster counties because the majority of the permanent TMI-1 workforce lives in those counties (see Section 3.4). The TMI-1 facility is located in southwestern Dauphin County. Lancaster County is located southeast of Dauphin County along the Susquehanna River. Lancaster County's population has increased 34.8 percent from the years 1970 to 2005. Dauphin County's population has increased 11.9 percent for the same 35-year period, an average annual increase of 0.4 percent (USCB 1995 and USCB 2006). Regional and local planning officials have shared goals of encouraging expansion and development in areas where public facilities, such as water and sewer systems, have been planned, and discouraging incompatible land use mixes in agricultural or open spaces.

The planning for both counties is driven in part by the Pennsylvania Municipalities Planning Code Act of 1968 which promotes the preservation of natural and historic resources and prime agricultural land and encourages the revitalization of established urban centers through the use of Designated Growth Areas (Lancaster County 2006). The act requires comprehensive planning on the part of counties. It is worth noting that due to the autonomous nature of the local municipalities (townships, villages and boroughs) in Pennsylvania that a county has limited legislative scope to implement the comprehensive plans. As a result, partnerships and coalitions of governing bodies are needed to implement the plans. Both Dauphin and Lancaster counties implement their comprehensive plans through townships and boroughs ordinances. Dauphin County is also involved in several regional comprehensive plans as a result of historic and strategic goals.

Dauphin County

Dauphin County is approximately 525 square miles in size and has 40 municipalities including the Pennsylvania state capital in Harrisburg (USCB 2005). The county is located in south-central Pennsylvania, along the Susquehanna River. Dauphin County's land use planning focuses on efficient use of land, and efficient expansion. The county planners are concerned about retaining enough area for future population growth and making growth decisions that don't overburden taxpayers. The county's focus is on revitalization of old areas, and managed growth that doesn't change rural character.

As part of the state capital region, the county has been involved in regional planning since 1956. Dauphin County has developed its future land use plan through the use of Planned Growth Areas. Dauphin County adopted the tool from the Regional Growth Management Plan produced by the Tri-County Regional Planning Commission, of which it is a member with neighboring Cumberland and Perry counties. Planned Growth Areas serve to place most development in areas that are already served by public services and have established infrastructure. The goal is to focus development in and around Community Service Areas where services such as sewer, water, transit, highway access, and community facilities exist to maximize the investment in existing infrastructure (Dauphin County 2007)

The Draft Dauphin County Comprehensive Plan describes the following land use.

- Residential use - 15 percent
- Public and Semi- Public Lands - 26 percent (two thirds comprised of state game lands and forest)
- Agricultural and Undeveloped Lands – 55 percent

- Industrial - 2 percent
- Transportation – less than 1 percent
- Commercial/Service – less than 1 percent each

In 2000, 34.5 percent of the county's residents lived in Harrisburg and 16 boroughs while others made their homes in townships and villages. As part of the Comprehensive Plan, the county has examined future land use by geographic planning sections designated by North Dauphin, Southeast Dauphin, Southwest Dauphin and the City of Harrisburg. The North section is characterized by low density residential development. The Southeast section is characterized by medium density residential development. The Southwest and the Harrisburg sections are characterized by high density mixed urban development (Dauphin County 2007).

Throughout the county, non-residential development occurs in a scattered fashion adjacent to roadways. The greatest concentration of non-residential strip development occurs between the City of Harrisburg and Derry Township, adjacent to U.S. Routes 83 and 322/422. Limited non-residential land use has occurred on limited access intersections of Interstates 81 and 83 and the Pennsylvania Turnpike. The portions of the county located in the heart of the Susquehanna Valley, contain the majority of the agricultural activity. The northeastern tier of the county is mountainous and forested (Dauphin County 2007).

The Land Needs Concept is at the heart of Dauphin County's future land use planning. The concept forecasts land use needs by considering regional population growth trends, employment needs as a result of this population growth, and real estate market projections. Previously, most planning did not take into account the big picture and relied solely on population projections. The current county future land use plan map designates only the land needed to accommodate the population projections through 2020. All other land is currently designated as Rural Reserve/Agriculture for future evaluation and use (Dauphin County 2007).

Lancaster County

Lancaster County is approximately 949 square miles in size and has 60 municipalities. The county is almost twice the size of Dauphin County in acreage and population (USCB 2006). According to the Lancaster Farmland Trust, Lancaster County holds the distinction of being the most productive non-irrigated farming county in the United States. The county and municipal planners are concerned about preserving the farming culture/heritage of the county, especially that of the Amish. Tourists visiting these areas add $1.6 billion annually to the county's economy. Farming plays a major role in the county and planning focuses on preservation of agricultural areas. Farmland in Lancaster County presently occupies 69 percent of the available land area. This planning goal differs from Dauphin County in that Lancaster wants to limit growth in rural areas to locations that have already been impacted by development. Lancaster also has a goal of revitalizing old areas.

Lancaster County's land use planning is built on the foundation that it is in the best interest of the residents that its agricultural heritage be preserved. In 1993, the county adopted a Growth Management element to its Comprehensive Plan. Future growth would be directed to Designated Growth Areas or areas already impacted by development to emphasize reinvestment in previously developed areas. The plan defined two growth areas as Urban Growth Areas and Village Growth Areas to manage future land use in the county (Lancaster County 2006). The growth areas have defined boundaries around a city, borough, or village and include the developed portions of surrounding townships and enough buildable land to meet future land use needs over a 20 year period. Since 1993, 39 growth areas have been established in the county. Further, between 1994 and 2002, residential land use outside Designated Growth Areas occurred at a net density of 0.8 dwellings per acre, while growth inside of Designated Growth Areas occurred at a net density of 5.5 dwellings per acre (Lancaster County 2006).

Currently, the largest residential, commercial and industrial development concentrations are found in the City of Lancaster and surrounding areas. Development can also be found on the major road corridors heading north and northwest (I-76, US 30, US 222, and PA 283) through the county.

The recent trends in rural growth in Lancaster County have been limited to areas where development had already been established. County planners have a goal of growth in these areas of less than 15 percent of total growth. Past trends show up to 27 percent growth outside developed areas, which results in noticeable impacts. County planners are sensitive to this, and measures will be taken to ensure that development in rural areas will be limited to additions that preserve the rural and agricultural culture. They also are encouraging governmental and private institutions to locate in urban centers (Lancaster County 2006).

In addition to Designated Growth Areas, Lancaster County has implemented 11 multi-municipal plans. These planned communities can work together to guide growth and preserve farmland and open space. Forty-one of the 60 county municipalities are involved in the multi-municipal planning efforts dating from 1993 to the present (Lancaster County 2006).

The Lancaster County Planning Commission has begun an update of the Growth Management Plan element of the Lancaster County Comprehensive Plan. The update will plan for growth thoroughout the county through 2030 and will be guided by the Policy Element of the Comprehensive Plan.

The Growth Management Plan Update will:

- examine current and projected growth patterns and infrastructure needs,
- review Urban and Village Growth Areas,
- address issues of concern within rural areas, and
- provide recommendations to achieve sustainable growth that balances development with the preservation of farmland and open space.

2.9 SOCIAL SERVICES AND PUBLIC FACILITIES

2.9.1 PUBLIC WATER SUPPLY

Because TMI-1 is in Londonderry Township (in Dauphin County) and most of the TMI-1 employees reside in Dauphin and Lancaster Counties, the discussion of public water supply systems will be limited to Dauphin and Lancaster Counties.

Dauphin County

Dauphin County is served by fourteen public water systems. The systems are owned by various entities, including municipalities, authorities, investors and the state government. In addition to the large public systems, there are small private systems provided for some mobile home parks. Public water systems serve approximately 240,000 persons with approximately 74,000 connections (Dauphin County 2007). The largest populations served are those receiving water from United Water Pennsylvania (86,500 persons served), the Harrisburg Municipal Water Authority (66,500 persons), and the Pennsylvania American Water Company-Hershey (38,000 persons) (PADEP 2005). The sources for these systems are primarily surface water (i.e. various creeks, streams and a reservoir), while the majority of the smaller systems are dependent upon groundwater sources (Dauphin County 2007).

County planners state that there is currently ample water to meet demand. However, planners predict that future growth will require system expansions and upgrades to assure adequate public water availability (Dauphin County 2007). Table 2.9-1 lists the largest municipal water suppliers (serving greater than 10,000 people) in Dauphin County.

Lancaster County

Over the last several decades, Lancaster County's population has grown at a faster rate than the Commonwealth of Pennsylvania (Section 2.6), reflecting an increase in demand for water and shelter. In the early 1990s, the Lancaster County Board of Commissioners adopted the Lancaster County Water Resources Plan, which is the plan currently in use. According to the plan, approximately 64 percent of Lancaster County's households were served by public water suppliers and private wells served the remaining 36 percent. Both surface and groundwater sources are tapped. Total average daily water consumption for all uses in the County was approximately 66 million gallons per day (MGD). Average daily water use was anticipated to increase by more than 18 MGD by 2010 (Lancaster County 1996).

Lancaster County has more than 30 larger community water suppliers. Although these larger systems draw from both ground and surface waters, they are increasingly dependent on groundwater to meet growing public demand. To meet these increasing demands, suppliers have made system improvements, drilled new wells, and extended service lines. In some cases, new authorities have been created and water systems have merged (Lancaster County 1996). Table 2.9-2 lists the largest municipal water suppliers (serving greater than 10,000 people) in Lancaster County.

Lancaster County has ample supply to meet the County's needs. However, County planning officials are concerned about future supplies. An analysis performed by the County indicates that approximately one-third of the large community water suppliers have sufficient water to meet 2010 demands. One-third may lack sufficient water for this period, while the remaining systems have an excess supply. Increased development has reduced the amount of land available for aquifer recharge. Also, water resources are impacted by pollutants from high traffic transportation corridors and industrial areas, excessive manure and sludge application, overuse of pesticides, urban and suburban runoff, and leaks, spills and dumps (Lancaster County 1996).

To address these issues, County planning officials are encouraging a variety of mitigations including: zoning; compaction of communities; protection of wetlands, forests, parks, and agricultural lands to enable better groundwater recharge; reduction of pollutants through the adoption of wellhead protection programs and the expansion of leak detection efforts; and the interconnection of systems having insufficient water supplies with those having excess supplies (Lancaster County 1996).

2.9.2 TRANSPORTATION

Dauphin and Lancaster Counties cover approximately 525 and 949 square miles, respectively (USCB 2006). TMI-1 is located in the southwest corner of Dauphin County (near the Lancaster County border), approximately 10 miles southeast of Harrisburg, Pennsylvania. Dauphin County is traversed by four interstate highways, 81, 83, 283, and 76. The nearest interstate, I-76, can be accessed approximately 7 miles north of TMI-1. See Figures 2.1-1 and 2.1-2 for locations.

Two major airports serve Dauphin County; the Harrisburg International Airport, in Lower Swatara Township, and the Capital City Airport in Fairview Township, York County. The Harrisburg International Airport is a passenger and air freight facility. The Capital City Airport is a public, general aviation airport. A second, but smaller, public general aviation airport is the Bendigo Airport which serves northern Dauphin County (Dauphin County 2007). Four airports serve Lancaster County. Two are in the central part of the county, and two are in the western part of the county. The Lancaster Airport is the largest of the four and provides passenger and freight services. The remaining three are general aviation airports available for public use (Lancaster County 2005).

Dauphin County is served by three passenger rail services. Harrisburg is the western terminus for Amtrak’s Keystone Corridor trains, which provide service between Harrisburg, Lancaster, Philadelphia, and New York. The county is also served by two other Amtrak trains: the Pennsylvanian and the Three Rivers. The Pennsylvanian runs between New York and Pittsburgh and the Three Rivers runs between New York and Chicago (Dauphin County 2007). Lancaster County is also served by the two passenger rail services. The Pennsylvania Department of Transportation and Amtrak are in the process of expanding and upgrading current rail services. Additionally, planning officials in the area are in the process of developing a regional rail system (Lancaster County 2005).

Road access to TMI-1 is via State Highway (SH-) 441, which has a north-south orientation. The plant has two access roads, Liberty Lane to the north (North Access Road), and Constitution Drive to the south (South Access Road) and they both intersect with SH-441 (Figure 2.1-3). The majority of the plant’s operations workforce uses the northern entrance, a limited number of employees working on the southern portion of the station and the outage and refurbishment workforces use the southern entrance. Approximately four to five miles north of TMI-1, SH-441 intersects with I-76, which has an east-west orientation (Figure 2.1-2). Employees traveling from the north (Harrisburg, Hummelstown, and Middletown, etc.), northeast, and northwest of TMI-1 would use I-76 and/or a variety of interstate, state, and secondary roads to access SH-441 to reach TMI-1. Employees traveling from the south and southeast (Elizabethtown, Mount Joy, and Lancaster, etc.) would use a variety of state highways and secondary roads to access SH-441 to reach TMI-1.

Employees traveling from the southwest would travel north to I-76, cross the Susquehanna River, and access SH-441 to reach TMI-1. Plant employees report no congestion on SH-441 near plant entrances.

In determining the significance levels of transportation impacts for license renewal, NRC uses the Transportation Research Board's level of service (LOS) definitions (NRC 1996). LOS is a qualitative measure describing operational conditions within a traffic stream and their perception by motorists. Traffic congestion conditions are rated as A through F and are designated as follows:

A -- Free flow of the traffic stream; users are unaffected by the presence of others.

B -- Stable flow in which the freedom to select speed is unaffected but the freedom to maneuver is slightly diminished.

C -- Stable flow that marks the beginning of the range of flow in which the operation of individual users is significantly affected by interactions with the traffic stream.

D -- High-density, stable flow in which speed and freedom to maneuver are severely restricted; small increases in traffic will generally cause operational problems.

E -- Operating conditions at or near capacity level causing low but uniform speeds and extremely difficult maneuvering that is accomplished by forcing another vehicle to give way; small increases in flow or minor perturbations will cause breakdowns.

F -- Defines forced or breakdown flow that occurs wherever the amount of traffic approaching a point exceeds the amount which can traverse the point. This situation causes the formation of queues characterized by stop-and-go waves and extreme instability.

The Pennsylvania Department of Transportation (PENNDOT) makes LOS determinations for roadways involved in specific projects. However, there are no current PENNDOT-generated LOS determinations for the roadways analyzed in this document. Dauphin County has provided LOS data for the portion of SH-441 within the borders of Dauphin County in its comprehensive plan. Lancaster County has not included LOS data in its comprehensive plan. Therefore, annual average daily traffic volumes are included for both counties and LOS data is included for Dauphin County. Table 2.9-3 lists roadways in the vicinity of TMI-1, the annual average number of vehicles per day as determined by PENNDOT, and LOS information as determined by Dauphin County.

2.10 METEOROLOGY AND AIR QUALITY

TMI-1 is located in Dauphin County in south-central Pennsylvania. The area is partially protected from severe weather by the Appalachian Mountains to the north. The climate is characterized by cold temperatures and frequent periods of snow during the winter and relatively warm humid summers with precipitation distributed evenly throughout the year (AmerGen 2006b). Meteorological information relevant to the severe accident mitigation alternatives analysis is provided in Section 4.20 and Appendix E.

Under the Clean Air Act, the U.S. Environmental Protection Agency (EPA) has established National Ambient Air Quality Standards (NAAQS), which specify maximum concentrations for nitrogen dioxide, sulfur dioxide, carbon monoxide, particulate matter with aerodynamic diameters of 10 microns or less (PM_{10}), particulate matter with aerodynamic diameters of 2.5 microns or less ($PM_{2.5}$), ozone, and lead. Areas of the United States having air quality as good as or better than the NAAQS are designated by EPA as attainment areas. Areas having air quality that is worse than the NAAQS are designated by EPA as non-attainment areas. Those areas that were previously designated nonattainment and subsequently redesignated to attainment due to meeting the NAAQS are maintenance areas. States with maintenance areas are required to develop an air quality maintenance plan as an element of the State Implementation Plan.

Dauphin County is part of the Harrisburg-Lebanon-Carlisle, Pennsylvania MSA. The EPA designated the entire MSA as a non-attainment area under the $PM_{2.5}$ NAAQS and a basic non-attainment area under the 8-hour ozone NAAQS. The Harrisburg-Lebanon-Carlisle MSA is designated as an attainment area for nitrogen dioxide, sulfur dioxide, carbon monoxide, PM_{10}, and lead (40 CFR 81.339).

The Clean Air Act, as amended, established 156 Mandatory Class I Federal Areas where visibility is an important issue. There are currently no Class I areas located within the state of Pennsylvania or within 100 miles of TMI-1 (40 CFR 81, Subpart D). The closest Class I area to TMI-1 is the Brigantine National Wildlife Area, which is located approximately 189 miles to the southeast of TMI-1 (Rand McNally 2006).

2.11 HISTORIC AND ARCHAEOLOGICAL RESOURCES

2.11.1 REGIONAL HISTORY IN BRIEF

Prehistoric

Aboriginal people migrated to Pennsylvania approximately 10,000 to 15,000 or more years ago. Three major cultural traditions dominated the prehistory of Pennsylvania: (1) the Paleo-Indian Tradition (15,000+ to 10,000 years ago); (2) the Archaic Tradition (10,000 to 3,000 years ago); and (3) the Woodland Tradition (3,000 years ago to European contact).

The Paleo-Indian period corresponds with the waning of the last glaciers. During glaciation, environmental zones were shifted hundreds of miles to the south, and now-extinct megafauna roamed the landscapes. It is believed that nomadic Paleo-Indians hunted these large animals. This period is characterized by the Clovis point, a distinctive, fluted, lanceolate point that is widely distributed throughout Pennsylvania, especially in the Susquehanna and Delaware River drainages. Pennsylvania Paleo-Indian sites also contain scrapers; spurred-end scrapers; drills; cores; bifaces; microblades; and small uniface, biface, and flake knives.

As the glaciers retreated into Canada, environmental zones shifted northward, eventually assuming positions closely approximating those of today. The largest fauna became extinct and humans adapted to exploit modern flora and fauna, particularly deer, elk, rabbits, and squirrels, and vegetable products of the forest, such as nuts and greens. The Archaic period was concomitant with the retreat of the glaciers and is characterized by the increasing use of a greater diversity of forest products and an apparent population increase. It is subdivided into the Early, Middle, and Late periods, each lasting two to three thousand years, and has several major cultural traditions – particularly the Laurentian, Lamoka, and Piedmont. Warming and the retreat of glaciers led to the succession of vegetation zones, tundra-spruce-fir-pine-mixed deciduous-oak-hickory, passing through Pennsylvania. Tool forms changed and the culture showed stylistic changes and increased diversity of forms. As megafauna became extinct, so did the fluted lanceolate point. It was replaced by forms more locally styled. Knives, scrapers, drills, and other chipped stone tools, as well as bone tools continued as important elements of Archaic assemblages.

The Archaic period was followed by the Woodland period, which is also subdivided into the Early, Middle, and Late periods. The major trait delineating the Woodland from the Archaic is the addition of ceramics. The practice of horticulture, the construction of earthen mounds for burial of the dead and later, the introduction of the bow and arrow are also considered Woodland innovations. During this period, the Hopewell culture dominated much of the eastern United States. Traces of the Hopewell culture are present in Pennsylvania.

Historic

In the mid 17th century, when the first Europeans came to the area now known as Pennsylvania, they found Late Woodland people, known as the Delaware, Shawnee, Iroquois, and Susquehannock. The Susquehannocks were an Iroquoian-speaking tribe who lived along the Susquehanna River in Pennsylvania and Maryland (PGA Undated). In fact, they inhabited an area about 20 miles downstream of TMI-1 in a town they called Sasquesahanaugh, on the east side of the Susquehanna River at Washington Boro (AEC 1972). Living in Algonkian-speaking tribes' territory, they engaged in many wars.

In the end, they were victims of diseases brought by European settlers, and attacks by Marylanders and the Iroquois which destroyed them as a nation by 1675. A few descendants were among the Conestoga Indians who were massacred in 1763 in Lancaster County (PGA Undated).

The rise of nation-states in Europe coincided with the gaining of lands in North America. Wars in southern Germany caused many Germans to migrate to Pennsylvania. The struggle in England between the Crown and Parliament and the quest for religious freedom brought Quakers, Puritans, and Catholics from England, and Scots Calvinists via Ireland. Huguenots left France for America (PGA Undated).

The first recorded European contact with present-day Pennsylvania was made by Captain John Smith who journeyed from Virginia up the Susquehanna River in 1608, visiting the Susquehannock Indians. Between 1609 and 1681, the Dutch, Swedes, and English inhabited and fought over the region that would later become eastern Pennsylvania. Ultimately, the English prevailed and the area fell under English rule.

William Penn was born in London on October 24, 1644. As a young man, he converted to the Society of Friends, or Quakers, then a persecuted sect. Seeking a haven in the New World for persecuted Friends, Penn asked the King to grant him land in the territory between Lord Baltimore's province of Maryland and the Duke of York's province of New York. With the Duke's support, Penn's petition was granted. The King signed the Charter of Pennsylvania on March 4, 1681, and it was officially proclaimed on April 2. The King named the new colony in honor of William Penn's father (PHMC Undated).

Although William Penn was granted all the land in Pennsylvania by the King, he and his heirs chose not to grant or settle any part of it without first buying the claims of Native Americans who lived there. In this manner, all of Pennsylvania except the northwestern third was purchased by 1768. The Commonwealth bought the claims to the remainder of the land by 1789 (PHMC Undated).

English Quakers were the dominant settlers, although a substantial number were Anglican. Thousands of Germans were also attracted to the colony and, by the time of the American Revolution, they comprised a third of the population. Another immigrant group was the Scotch-Irish, who migrated from about 1717 until the American Revolution in a series of waves caused by hardships in Ireland (PHMC Undated).

Other Quakers were Irish and Welsh. They, together with the French Huguenots, Jewish settlers, Dutch, Swedes, and other groups, contributed in smaller numbers to the development of colonial Pennsylvania (PHMC Undated).

Despite Quaker opposition to slavery, about 4,000 slaves were brought to Pennsylvania by 1730, most of them owned by English, Welsh, and Scots-Irish colonists. The census of 1790 showed that the number of African-Americans had increased to about 10,000, of whom about 6,300 were free (PHMC Undated).

2.11.2 INITIAL CONSTRUCTION AND OPERATION

The Final Environmental Statement (FES) for operation of Three Mile Island Nuclear Station listed three properties on the National Register of Historic Places (National Register) that were within 17 miles of the site and two properties eligible for listing on the National Register that were within 5 miles of the site (AEC 1972). The National Register sites were: Walnut Street Bridge, 11 miles north of the station in Harrisburg; Cornwall Iron Furnace, 17 miles northeast in Lebanon County; and Billmeyer House in York, 14 miles south of the site.

The sites eligible for listing on the National Register were: St. Peter's Evangelical Lutheran Church, 3 miles north of the site; and a cemetery, slightly further north (AEC 1972).

Additionally, the Atomic Energy Commission (AEC) reported that, in 1967, the applicants for Three Mile Island Nuclear Station funded an archaeological survey and subsequent excavation of artifacts from the island prior to construction. The survey and excavation was conducted by the Pennsylvania Historical and Museum Commission (PHMC 1977). More than 1,000 artifacts were found and, from these artifacts, it was deduced that the site had period components ranging from 4,000 B.C. to 1000+ A.D. The artifacts having most importance for understanding the way of life of an early people were from the Early and Middle Woodland cultures, because these are poorly known eras of Pennsylvania prehistory.

Comments included in the FES by the Advisory Council on Historic Preservation, United States Department of the Interior, and Pennsylvania Historical and Museum Commission, indicated that the operation of Three Mile Island Nuclear Station would have no significant adverse effect on cultural resources in the area (AEC 1972)

2.11.3 OTHER CULTURAL RESOURCE ACTIVITIES IN THE AREA

In April, 1987, a paper was presented at the Mid Atlantic Archaeological Conference Annual Meeting in Lancaster, Pennsylvania by two archaeologists detailing work they'd performed in relation to Three Mile Island (Mangold and Grace 1987). The archaeologists wanted to more clearly define the cultural occupations of the island by 1) inspecting extant private collections of those who have collected artifacts from Three Mile Island, 2) reviewing previous archaeological investigations, and 3) performing limited testing on the island. Their investigation led to the conclusion that cultures from the prehistoric Early Archaic through the historic Susquehannock Indians have used the island and that much of the cultural data, stratigraphy, and features indicating human activity remain to be investigated.

In 1988, the Curator of Archaeology from the State Museum of Pennsylvania performed an investigation of a burial site discovered on the southern tip of the island by a TMI-1 employee. The Curator concluded that the human burial was not the product of a recent homicide, but the remains of a 19th century island resident. The remains were collected and later reburied in a location near their original burial site. Associated cultural materials (i.e., clothing buttons, coffin nails, etc.) were collected and donated to the State Museum of Pennsylvania for perpetual curation.

In 1999, the Pennsylvania Historical and Museum Commission held a public history symposium and erected a "historical marker" on SH-441, south of the Three Mile Island Nuclear Station Visitor Center sign, commemorating the 20th anniversary of the TMI-2 accident. The symposium was a cooperative effort of the Pennsylvania Department of Environmental Protection, the Pennsylvania Historical and Museum Commission, Penn State Harrisburg, the NRC, GPU Nuclear Incorporated, Three Mile Island Alert, Middletown Borough, and Londonderry Township (PHMC 1999).

2.11.4 CURRENT STATUS

As of 2006, the National Register of Historic Places listed 65 sites in Dauphin County, 207 sites in Lancaster County, and 92 sites in York County, Pennsylvania (USDOI 2006). Of these 364 sites, 19 fall within a 6-mile radius of TMI-1.

As of 2006, the Department of the Interior listed properties that are currently determined eligible for listing on the

National Register of Historic Places within the same three counties: 33 sites in Dauphin County, 13 sites in Lancaster County, and 14 sites in York County, Pennsylvania (USDOI 2006). Of these 60 sites, 4 fall within a 6 mile radius of TMI-1. Table 2.11-1 contains the sites located within a six-mile radius of TMI-1 that either are listed in the National Register of Historic Places or have been determined by the Department of Interior to be eligible for listing. Figure 2.1-2 depicts the area around TMI-1 bounded by the 6-mile radius.

The 200-acre area occupied by the TMI-1 facilities on Three Mile Island consists entirely of land disturbed by prior industrial activities. No properties listed or eligible for listing on the National Register of Historic Places are known to be located within this area.

2.12 KNOWN OR REASONABLY FORESEEABLE PROJECTS IN SITE VICINITY

As indicated on Figure 2.1-1, there are three urban areas, Harrisburg, Lancaster, and York, PA, within 25 miles of the TMI-1 plant site. Within a six-mile radius (Figure 2.1-2) of TMI-1, the nearest population centers are Royalton and Middletown. Farms, residential neighborhoods consisting primarily of older single-family homes, and few commercial and/or industrial facilities are located within the immediate vicinity.

Three Mile Island Unit 2

On March 28, 1979, TMI-2 suffered a severe accident that led to partial melting of the reactor core. Detailed studies of the radiological consequences of the accident have been conducted by the NRC, the EPA, the Department of Health, Education and Welfare (now Health and Human Services), the Department of Energy, and the State of Pennsylvania. Several independent studies have also been conducted. Estimates are that the average dose to about 2 million people in the area was only about 1 millirem. The maximum dose to a person at the site boundary would have been less than 100 millirem (NRC 2005).

In the months following the accident, thousands of environmental samples of air, water, milk, vegetation, soil, and foodstuffs were collected by various groups monitoring the area. Very low levels of radionuclides could be attributed to releases from the accident. However, comprehensive investigations and assessments by several well-respected organizations have concluded that in spite of serious damage to the reactor, most of the radiation was contained and that the actual release had negligible effects on the physical health of individuals or the environment (NRC 2005).

TMI-2, which is owned by FirstEnergy Corporation, has been permanently shut down and is now in a safe storage mode called Post Defueling Monitored Storage (PDMS). The only TMI-2 systems, structures or components that are relied upon for the operation of TMI-1 are the Station Blackout Diesel Generator Building and the TMI-2 Fuel Handling Building (Figure 3.1-1). No TMI-2 activities are within the scope of the TMI-1 license renewal application.

FirstEnergy Corporation has contracted with AmerGen to perform maintenance and administration functions for TMI-2. It is anticipated that these maintenance and administration functions would continue to be performed during TMI-1 license renewal period.

Independent Spent Fuel Storage Installation

AmerGen may construct an Independent Spent Fuel Storage Installation (ISFSI) at TMI-1, if a federal facility is not operational, to store additional spent fuel through the license renewal term. Construction of the ISFSI would need to be completed by 2024.

Military Installations

The Defense Distribution Depot Susquehanna, Pennsylvania (DDSP) was created in 1991 with the merger of the New Cumberland Army Depot (NCAD) and the Defense Logistics Agency (DLA) Defense Depot Mechanicsburg. DDSP is the largest Department of Defense wholesale distribution depot in the United States (Global Security 2005).

Comprised of over two thousand employees, DDSP operates a campus at the Navy Inventory Control Point, Mechanicsburg, and in New Cumberland at the NCAD site. The majority of employees are located at the New Cumberland site. The remaining employees are located at the Mechanicsburg site, which is about 7 miles from New Cumberland. The New Cumberland installation encompasses 851 acres along the Susquehanna River in New Cumberland, Pennsylvania, about 5 miles south of Harrisburg. Facilities within the installation include over 200 buildings, 26 miles of roads, and 18 miles of railroad (Global Security 2005).

In its 2005 Base Realignment and Closure recommendations, the Department of Defense recommended a realignment of DDSP. This recommendation was predicted to result in a maximum loss of 31 jobs in the Harrisburg-Carlisle, PA, Metropolitan Statistical Area over the 2006-2011 time period (Global Security 2005).

EPA-Regulated Facilities in Dauphin, Lancaster, and York Counties

In its "Envirofacts Warehouse" online database, EPA identifies permitted dischargers to air, land, and water. A search in Dauphin County revealed 137 facilities that are permitted to discharge to the waters of the United States, 208 facilities that produce and release air pollutants, 37 facilities that have reported toxic releases, 547 facilities that have reported hazardous waste activities, and five potentially hazardous waste sites that are part of Superfund (USEPA 2006).

A search in Lancaster County revealed 330 facilities that are permitted to discharge to the waters of the United States, 317 facilities that produce and release air pollutants, 162 facilities that have reported toxic releases, 1,194 facilities that have reported hazardous waste activities, and 16 potentially hazardous waste sites that are part of Superfund (USEPA 2006).

A search in York County revealed 223 facilities that are permitted to discharge to the waters of the United States, 279 facilities that produce and release air pollutants, 140 facilities that have reported toxic releases, 926 facilities that have reported hazardous waste activities, and 11 potentially hazardous waste sites that are part of Superfund (USEPA 2006).

Detailed information concerning these facilities may be accessed through EPA's "Envirofacts Warehouse".

Electricity Generating Stations in the Vicinity of TMI-1

York Haven Hydroelectric Station

The York Haven Hydroelectric Station, completed in 1904, is approximately one mile southwest of TMI-1. It is a low-head, run-of-the-river dam and hydroelectric plant and is located on the Susquehanna River at Conewago Falls, where the river drops 19 feet in ¼ mile. The major axis of the 5,000 foot diversion dam is north to south and connects to a 3,000 foot headrace which heads southeast. The dam and headrace are layered out along natural rock formations in the river. The southeastern end is on the western bank at the borough of York Haven, Pennsylvania and the north ends adjoins Three Mile Island. There is another smaller dam (Red Hill) that connects the eastern shore of Three Mile Island to the western mainland. The hydroelectric plant is located on the western shoreline of the river. As discussed in Section 2.2.3, the plant is equipped with 13 horizontal and 7 vertical generators that produce 19-20 MW of electrical power. York Haven Holdings, Inc., an affiliate of the privately-owned U.S. independent power producer Olympus Power LLC owns the facility.

Brunner Island Generating Station

Brunner Island is a three-unit, 1,483 MW, coal-fired plant located on the west bank of the Susquehanna River in York County, about 5 miles downstream from Three Mile Island (Figure 2.1-2). Brunner Island Unit 1 began commercial operation in 1961; it has

334 MW of generating capacity. Unit 2, which began commercial operation in 1965, has 390 MW of generating capacity. Unit 3 came on-line in 1969 and has 759 MW of generating capacity. Brunner Island is owned and operated by PPL Brunner Island, LLC which is a subsidiary of PPL Corporation (Pennsylvania Power & Light Undated).

Table 2.2-1. Monthly average, minimum, and maximum ΔT (degrees F) based on automatic temperature sensors at the intake screen pumphouse and at the discharge monitoring pit.

Year	Month	Average ΔT	Minimum ΔT	Maximum ΔT
2005	August	11.66	7.50	13.80
2005	September	11.04	2.76	16.46
2005	October	11.16	1.61	16.58
2005	November	5.98	0.78	14.67
2005	December	11.13	4.74	14.02
2006	January	9.47	6.30	10.77
2006	February	9.43	6.35	11.67
2006	March	12.23	5.32	17.04
2006	April	15.86	11.26	30.16
2006	May	16.10	7.13	20.61
2006	June	17.80	8.96	22.68
2006	July	16.59	9.72	21.17
2006	August	16.86	11.99	21.88
2006	September	18.84	10.26	21.56
2006	October	17.10	10.18	21.27
2006	November	16.04	4.83	22.41
2006	December	17.17	5.42	21.71
2007	January	16.88	11.35	20.22
2007	February	17.32	11.01	19.36
2007	March	17.35	9.64	24.37
2007	April	20.55	10.99	28.96
2007	May	21.01	15.97	27.08
2007	June	14.87	8.67	19.17
2007	July	15.01	11.62	18.04
2007	August	13.95	10.08	16.53
2007	September	15.56	8.74	20.95

Source: AmerGen (2007b).

Table 2.2-2. Passage of American shad, walleye, smallmouth bass, and gizzard shad at the York Haven fishway since it became operational in 2000

Year	American Shad	Walleye	Smallmouth Bass	Gizzard Shad
2000	4,675	4,581	1,916	79,972
2001	16,200	10,260	3,414	89,272
2002	1,555	14,415	4,403	100,779
2003	2,536	8,132	2,242	113,513
2004	219	1,178	159	84,234
2005	1,772	3,946	832	12,805
2006	1,913	NA	NA	NA
Totals	28,870	42,512	12,966	480,575

Source: Pennsylvania Fish and Boat Commission (Undated).
NA = Not Available

Table 2.5-1. Endangered and Threatened Species that could Occur in the Vicinity of TMI-1 or in Counties Crossed by TMI-1 Transmission Lines.

Scientific Name	Common Name	Federal Status	State Status
Mammals			
Cryptotis parva	Least shrew	-	E
Neotoma magister	Allegheny woodrat	-	T
Birds			
Bartramia longicauda	Upland sandpiper	-	T
Botaurus lentiginosus	American bittern	-	E
Casmerodius alba	Great egret	-	E
Cistothorus platensis	Sedge wren	-	E
Falco peregrinus	Peregrine falcon	-	E
Haliaeetus leucocephalus	Bald eagle	-	T
Nyctanassa violacea	Yellow-crowned night heron	-	E
Nycticorax nycticorax	Black-crowned night heron	-	E
Pandion haliaetus	Osprey	-	T
Rallus elegans	King rail	-	E
Reptiles			
Clemmys muhlenbergii	Bog turtle	T	E
Opheodrys aestivus	Rough green snake	-	E
Pseudemys rubriventris	Redbelly turtle	-	T
Fish			
Ameiurus melas	Black bullhead	-	E
Invertebrates			
Alasmidonta heterodon	Dwarf wedgemussel	E	E
Plants			
Agalinis auriculata	Eared false- foxglove	-	E
Ammannia coccinea	Scarlet ammannia	-	E
Arethusa bulbosa	Swamp-pink	-	E
Aristida purpurascens	Arrow-feathered three awned	-	T
Arnica acaulis	Leopard’s-bane	-	E
Asplenium bradleyi	Bradley’s speenwort	-	T
Boltonia asteroids	Aster-like boltonia	-	E
Carex aquatilis	Water sedge	-	T
Carex bullatta	Bull sedge	-	E
Carex diandra	Lesser panicled sedge	-	T
Carex polymorpha	Variable sedge	-	E
Carex prairea	Prairie sedge	-	T
Carex sterilis	Sterile sedge	-	T
Carex tetanica	Rigid sedge	-	T
Carex typhina	Cattail sedge	-	E

Table 2.5-1. Endangered and Threatened Species that could Occur in the Vicinity of TMI-1 or in Counties Crossed by TMI-1 Transmission Lines (continued)

Scientific Name	Common Name	Federal Status	State Status
Cirsium horridulum	Horrible thistle	-	E
Cladium mariscoides	Twig rush	-	E
Clitoria mariana	Butterfly-pea	-	E
Cynanchum laeve	Smooth swallow-wort	-	E
Cyperus diandrus	Umbrella flatsedge	-	E
Cyperus refractus	Reflexed flatsedge	-	E
Cyperus retrorsus	Retrorse flatsedge	-	E
Cypripedium reginae	Showy lady's-slipper	-	T
Dodecatheon radicatum	Jeweled shooting-star	-	T
Eleocharis compressa	Flat-stemmed spike-rush	-	E
Eleocharis intermedia	Matted spike-rush	-	T
Elephantopus carolinianus	Elephant's foot	-	E
Ellisia nyctelea	Ellisia	-	T
Epilobium strictum	Downy willow -herb	-	E
Erigenia bulbosa	Harbinger-of-spring	-	T
Euphorbia purpurea	Glade spurge	-	E
Festuca paradoxa	Cluster fescue	-	E
Fimbristylis annua	Annual fimbry	-	T
Gaylussacia dumosa	Dwarf huckleberry	-	E
Gymnopogon ambiguus	Broad-leaved beardgrass	-	E
Helianthemum bicknellii	Bicknell's hoary rockrose	-	E
Hypericum densiflorum	Bushy Saint John's-wort	-	T
Ilex opaca	American holly	-	T
Iris cristata	Crested dwarf iris	-	E
Iris prismatica	Slender blue Iris	-	E
Iris verna	Dwarf Iris	-	E
Juncus articus var. littoralis	Baltic rush	-	T
Juncus brachycephalus	Small-headed rush	-	T
Juncus dichotomus	Forked rush	-	E
Juncus scirpoides	Scirpus-like rush	-	E
Linum intercursum	Sandplain wild flax	-	E
Linum sulcatum	Grooved yellow flax	-	E
Lipocarpha micrantha	Common hemicarpa	-	E
Lobelia kalmii	Brook lobelia	-	E
Lobelia puberula	Downy lobelia	-	E
Ludwigia polycarpa	False loosestrife seedbox	-	E
Lycopodiella appressa	Southern bog clubmoss	-	T
Lyonia mariana	Stagger-bush	-	E

Table 2.5-1. Endangered and Threatened Species that could Occur in the Vicinity of TMI-1 or in Counties Crossed by TMI-1 Transmission Lines (continued)

Scientific Name	Common Name	Federal Status	State Status
Magnolia tripetala	Umbrella magnolia	-	T
Magnolia virginiana	Sweet Bay magnolia	-	T
Matelea oblique	Oblique milkvine	-	E
Melica nitens	Three-flowered melic-grass	-	T
Myriophyllum sibiricum	Northern water-milfoil	-	E
Panicum scoparium	Velvety panic grass	-	E
Passiflora lutea	Passion-flower	-	E
Phemeranthus teretifolius	Round-leaved fame flower	-	T
Phlox ovata	Mountain phlox	-	E
Phyllanthus caroliniensis	Carolina leaf-flower	-	E
Poa paludigena	Bog bluegrass	-	T
Polygala cruciata	Cross-leaved milkwort	-	E
Polygala incarnata	Pink milkwort	-	E
Polygonum setaceum var. interjectum	Swamp smartweed	-	E
Potamogeton hillii	Hill’s pondweed	-	E
Potamogeton obtusifolius	Blunt-leaved pondweed	-	E
Potamogeton richardsonii	Red-head pondweed	-	T
Pycnanthemum torrei	Torry’s mountain-mint	-	E
Quercus shumardii	Shumard’s oak	-	E
Ranunculus fascicularis	Tufted buttercup	-	E
Rhexia mariana	Maryland meadow-beauty	-	E
Rhododendron atlanticum	Dwarf azalea	-	E
Rhynchospora capillacea	Capillary beaked-rush	-	E
Ruellia strepens	Limestone petunia	-	T
Scheuchzeria palustris	Pod-grass	-	E
Schoenoplectus smithii	Smith’s bulrush	-	E
Scirpus ancistrochaetus	Northeastern bulrush	E	E
Scleria pauciflora	Few flowered nutrush	-	T
Scleria verticillata	Whorled nutrush	-	E
Sericocarpus linifolius	Narrow-leaved white-topped Aster	-	E
Sida hermaphrodita	Sida	-	E
Sisyrinchium atlanticum	Eastern blue-eyed grass	-	E
Solidago simplex ssp. Randii var. racemosa	Sticky golden-rod	-	E
Solidago speciosa var. erecta	Slender golden-rod	-	E
Sparganium androcladum	Branching bur-reed	-	E
Spiranthes vernalis	Spring ladies’-tresses	-	E

Table 2.5-1. Endangered and Threatened Species that could Occur in the Vicinity of TMI-1 or in Counties Crossed by TMI-1 Transmission Lines (continued)

Scientific Name	Common Name	Federal Status	State Status
Sporobolus clandestinus	Rough dropseed	-	E
Sporobolus heterolepis	Prairie dropseed	-	E
Symphyotrichum depauperatum	Serpentine aster	-	T
Thalictrum coriaceum	Thick-leaved meadow-rue	-	E
Triphora trianthophora	Nodding pogonia	-	E
Vernonia glauca	Tawny ironweed	-	E
Viburnum nudum	Possum-haw	-	E
Vittaria appalachiana	Appalachian gametophyte fern	-	T

Note: E = Endangered; T = Threatened; - = Not listed.
Source: FWS (2006), PNHP (2006) and PNHP (2007).

Table 2.6-1. Residential Distribution of TMI-1 Employees

County of Residence	Number of Employees	Percent of Total
Dauphin County, PA	196	37.3%
Lancaster County, PA	176	33.5%
Lebanon County, PA	57	10.9%
York County, PA	41	7.8%
Cumberland County, PA	26	5.0%
Perry County, PA	7	1.3%
Berks County, PA	6	1.1%
Chester County, PA	5	1.0%
Atlantic County, NJ	1	0.2%
Cambria County, PA	1	0.2%
Cobb County, GA	1	0.2%
Dupage County, IL	1	0.2%
Juniata County, PA	1	0.2%
McLean County, IL	1	0.2%
Montgomery County, PA	1	0.2%
Philadelphia County, PA	1	0.2%
Roseau County, MN	1	0.2%
Schuylkill County, PA	1	0.2%
Susquehanna County, PA	1	0.2%
TOTAL	**525**	**100.0%**

Source: AmerGen

Table 2.6-2. Decennial Populations and Growth Rates

	Population and Decennial Growth Rate					
	Dauphin County		Lancaster County		Pennsylvania	
Year	**Number**	**Percent**	**Number**	**Percent**	**Number**	**Percent**
1980	232,317	--	362,346	--	11,863,895	--
1990	237,813	2.4	422,822	16.7	11,881,643	0.2
2000	251,798	5.9	470,658	11.3	12,281,054	3.4

Note: The Commonwealth of Pennsylvania has not updated county projections using 2000 census data.
Source: USCB (1995) and USCB (2000)

Table 2.6-3. Environmental Justice Summary

State	County	Number of Block Groups	Black	American Indian or Alaskan Native	Asian	Native Hawaiian or Other Pacific Islander	Other Race	Multi-Racial	Aggregate of Races*	Hispanic Ethnicity	Low-Income Households	2000 Population within 50 Miles
Block Groups where the Minority or Low-Income Population is 20% Greater than the State Percentage												
Maryland	Baltimore	91	0	0	0	0	0	0	0	0	1	129284.4
Maryland	Carroll	69	0	0	0	0	0	0	0	0	1	101670.4
Maryland	Cecil	13	0	0	0	0	0	0	0	0	0	15809.2
Maryland	Frederick	13	0	0	0	0	0	0	0	0	0	9795.5
Maryland	Harford	74	0	0	0	0	0	0	0	0	0	109499.6
Maryland	Washington	1	0	0	0	0	0	0	0	0	0	37.6
Pennsylvania	Adams	54	0	0	0	0	0	0	0	0	1	91292.0
Pennsylvania	Berks	221	1	0	0	0	34	0	42	51	16	289969.9
Pennsylvania	Chester	55	10	0	0	0	1	0	9	2	3	76237.4
Pennsylvania	Columbia	2	0	0	0	0	0	0	0	0	0	659.7
Pennsylvania	Cumberland	137	1	0	0	0	0	0	1	0	5	213674.0
Pennsylvania	Dauphin	191	48	0	0	0	1	0	52	6	12	251798.0
Pennsylvania	Franklin	36	0	0	0	0	0	0	0	0	0	35529.0
Pennsylvania	Juniata	19	0	0	0	0	0	0	0	0	0	20557.0
Pennsylvania	Lancaster	317	1	0	0	0	16	0	25	31	11	470658.0
Pennsylvania	Lebanon	85	0	0	0	0	0	0	0	5	2	120327.0
Pennsylvania	Mifflin	1	0	0	0	0	0	0	0	0	0	347.2
Pennsylvania	Northumberland	66	1	0	0	0	0	0	1	0	3	59964.7
Pennsylvania	Perry	35	0	0	0	0	0	0	0	0	0	43576.3
Pennsylvania	Schuylkill	94	1	0	0	0	0	0	0	0	2	92395.0
Pennsylvania	Snyder	29	0	0	0	0	0	0	0	0	0	31646.1
Pennsylvania	York	328	15	0	0	0	4	0	25	10	9	381751.0
TOTALS:		**1931**	**78**	**0**	**0**	**0**	**56**	**0**	**155**	**105**	**66**	**2546478.9**
Block Groups where the Minority or Low-Income Population is Greater than 50%												
Maryland	Baltimore	**91**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**0**	**1**	
Maryland	Carroll	**69**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Maryland	Cecil	**13**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Maryland	Frederick	**13**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Maryland	Harford	**74**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	

Table 2.6-3. Environmental Justice Summary (continued)

State	County	Number of Block Groups	Black	American Indian or Alaskan Native	Asian	Native Hawaiian or Other Pacific Islander	Other Race	Multi-Racial	Aggrega te of Races*	Hispanic Ethnicity	Low-Income Households	2000 Population within 50 Miles
Maryland	Washington	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Pennsylvania	Adams	**54**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Pennsylvania	Berks	**221**	**0**	**0**	**0**	**0**	**1**	**0**	**26**	**22**	**5**	
Pennsylvania	Chester	**55**	**8**	**0**	**0**	**0**	**0**	**0**	**9**	**0**	**1**	
Pennsylvania	Columbia	**2**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Pennsylvania	Cumberland	**137**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	
Pennsylvania	Dauphin	**191**	**28**	**0**	**0**	**0**	**0**	**0**	**37**	**0**	**3**	
Pennsylvania	Franklin	**36**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Pennsylvania	Juniata	**19**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Pennsylvania	Lancaster	**317**	**0**	**0**	**0**	**0**	**1**	**0**	**15**	**11**	**0**	
Pennsylvania	Lebanon	**85**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Pennsylvania	Mifflin	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Pennsylvania	Northumberland	**66**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	
Pennsylvania	Perry	**35**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Pennsylvania	Schuylkill	**94**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Pennsylvania	Snyder	**29**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Pennsylvania	York	**328**	**2**	**0**	**0**	**0**	**0**	**0**	**13**	**0**	**2**	
TOTALS:		**1931**	**38**	**0**	**0**	**0**	**2**	**0**	**101**	**33**	**14**	

State Percentages

State	Number of Block Groups	Black	American Indian or Alaskan Native	Asian	Native Hawaiian or Other Pacific Islander	Other Race	Multi-Racial	Aggrega te of Races*	Hispanic Ethnicity	Low-Income Households
Maryland		27.89	0.29	3.98	0.04	1.80	1.96	35.97	4.30	8.32
Pennsylvania		9.97	0.15	1.79	0.03	1.53	1.16	14.63	3.21	10.99

Note - For the Aggregate Category, the percentage of the Aggregate of Races for the state of Maryland is 35.97. Therefore, more block groups fall in the "Greater than 50%" category than "20% greater than the state average" (for Maryland only).
- Shaded areas are counties completely contained within the 50-mile radius of the TMI-1 site.

Source: USCB (2000)

Table 2.7-1. TMI-1 Tax Information 2000-2005

Year	Dauphin County Tax Revenues	TMI-1 Property Tax Paid to Dauphin County	Percent of Dauphin County Revenues	Londonderry Township Tax Revenues	TMI-1 Property Tax Paid to Londonderry Township	Percent of Londonderry Township Revenues	Lower Dauphin School District Tax Revenues	TMI-1 Property Tax Paid to Lower Dauphin School District	Percent of Lower Dauphin School District Revenues
2000	58,000,000	$146,940	0.3	4,026,239	$30,000	0.7	13,750,583 2000-2001	$394,500	2.9
2001	60,050,000	$146, 940	0.2	4,768,643	$30,000	0.6	14,085,270 2001-2002	$394,500	2.8
2002	60,500,000	$146, 940	0.2	5,093,487	$30,000	0.6	15,836,551 2002-2003	$394,500	2.5
2003	61,500,000	$146, 940	0.2	5,602,437	$30,000	0.5	17,483,255 2003-2004	$394,500	2.3
2004	73,900,000	$146, 940	0.2	6,251,276	$30,000	0.5	18,572,668 2004-2005	$394,500	2.1
2005	89,300,000	$141,630	0.2	6,356,814	$20,972	0.3	20,095,292 2005-2006 (budgeted)	$343,000	1.7

Source: Exelon

Table 2.9-1. Major Dauphin County Public Water Suppliers

Water Supplier	Average Production (GPD)	Maximum Production (GPD)	Design Capacity (GPD)	Storage Capacity (GPD)
Harrisburg Municipal Water Authority	9,000,000	16,100,000	20,000,000	40,000,000
Pennsylvania American Water Company-Hershey	6,000,000	8,000,000	9,000,000	8,240,000
United Water Pennsylvania	11,003,000	12,000,000	15,800,000	8,050,000

GPD = Gallons per day
Note: Municipal water suppliers serving populations greater than 10,000.
Source: PADEP (2005)

Table 2.9-2. Major Lancaster County Public Water Suppliers

Water Supplier	Average Production (GPD)	Maximum Production (GPD)	Design Capacity (GPD)	Storage Capacity (GPD)
City of Lancaster	16,134,000	30,000,000	40,000,000	34,600,000
Columbia Water Company	1,934,238	2,240,000	3,000,000	8,450,000
Elizabethtown Area Water	1,015,000	1,506,000	1,667,000	1,625,000
Ephrata Area Joint Authority	1,763,347	2,762,000	4,096,000	4,873,000
East Hempfield Water Authority	1,500,000	2,370,000	2,854,000	5,380,000

GPD = Gallons per day
Note: Municipal water suppliers serving populations greater than 10,000.
Source: PADEP (2005)

Table 2.9-3. Roadway Information (Dauphin and Lancaster Counties)

Roadway and Location	LOS Data (Dauphin County)	Annual Average Daily Traffic (AADT)
SH-441, just north of Interstate 76	B	7,000
SH-441, south of Interstate 76, near Middletown	B	6,900
SH-441, south of Interstate 76, near Royalton	B	3,800
SH-441, near northern entrance to TMI-1 site	A	3,800
SH-441, between Dauphin County border and intersection with SH-241	N/A	3,600
SH-441, between intersection with SH-241 and intersection with SH-743	N/A	5,500 to 6,000
SH-441, between intersection with SH-743 and intersection with SH-772	N/A	12,000
SH-441, between intersection with SH-772 and intersection with SH-23	N/A	16,000
SH-441, between intersection with SH-23 and intersection with U.S. Route 30	N/A	17,000
SH-441, between intersection with U.S. Route 30 and intersection with SH-462	N/A	11,000

Sources: PENNDOT (2004) and Dauphin County (2005)
LOS – Level of Service
N/A – Information not available.
SH – State Highway
Note: Locations are approximations derived from PENNDOT traffic count maps.

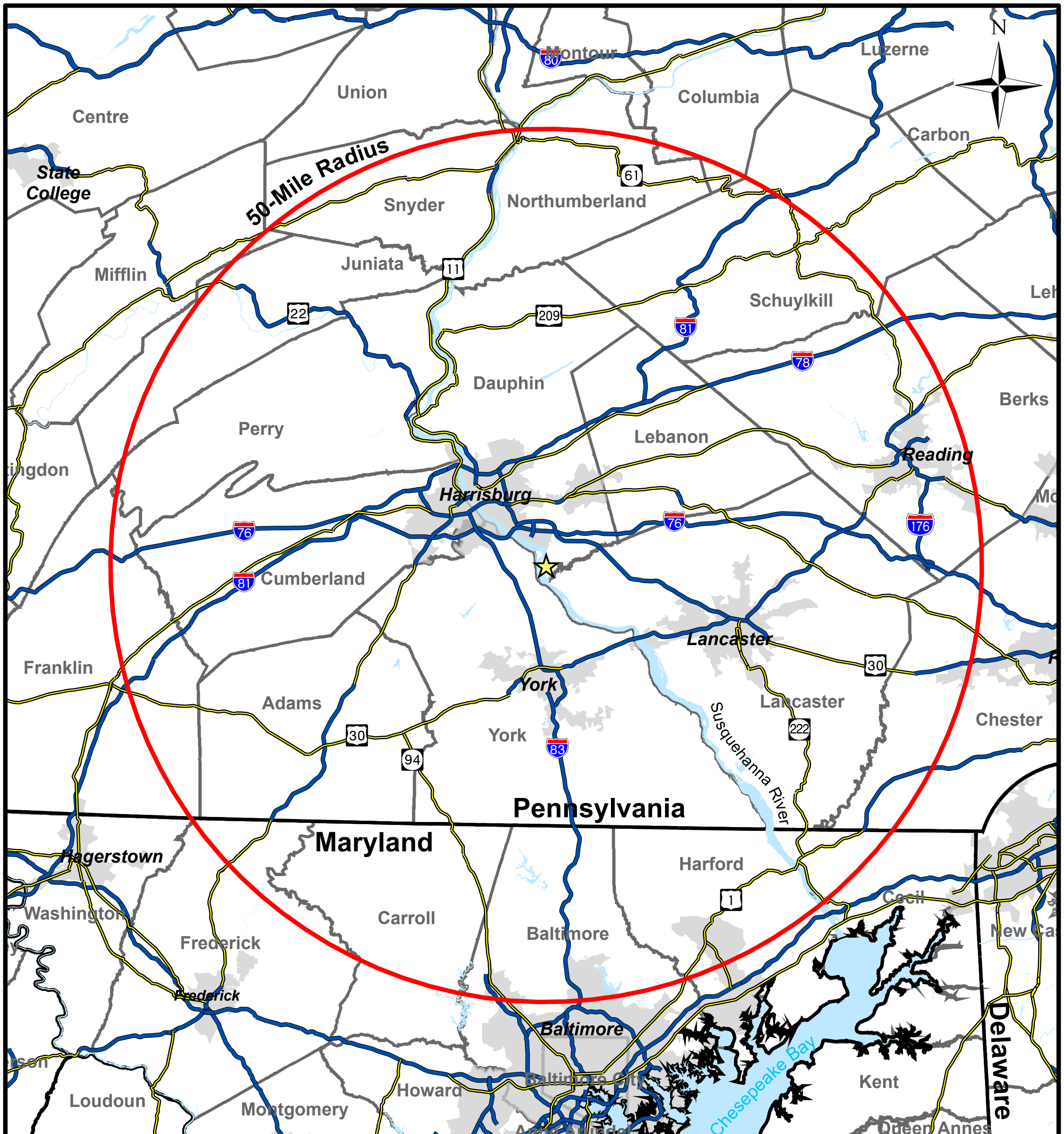
Table 2.11-1. Sites Listed in the National Register of Historic Places and Sites Determined Eligible for Listing that fall within a 6-mile Radius of TMI-1

Site Name	Location
National Register of Historic Places Sites	
Byers-Muma House	1402 Trout Run Road, East Donegal Lancaster County
Donegal Presbyterian Church Complex	Donegal Springs Road, East Donegal Lancaster County
Kreider Shoe Manufacturing Company	155 South Poplar Street, Elizabethtown Lancaster County
B'Nai Jacob Synagogue	Nissley and Water Streets, Middletown Dauphin County
Simon Cameron House and Bank	28 and 30 East Main Street, Middletown Dauphin County
Henniger Farm Covered Bridge	Northeast of Elizabethville Dauphin County
Highspire High School	221 Penn Street, Highspire Dauphin County
Charles and Joseph Raymond Houses	37 and 38 North Union Street, Middletown Dauphin County
Henry Smith Farm	950 Swatara Creek Road, Middletown Dauphin County
St. Peter's Kierch	31 West High Street, Middletown Dauphin County
Star Barn Complex	Nissley Drive at PA 283, Lower Swatara Dauphin County
Swatara Ferry House	400 Swatara Street, Middletown Dauphin County
Michael and Magdealena Bixler Farmstead	400 Mundis Race Road, East Manchester York County
Codorus Forge and Furnace Historic District	Junction of River Farm and Furnace Roads, Hellam Township, Saginaw York County
Goldsboro Historic District	Roughly bounded by North, Third, Fraser, and Railroad Streets, Borough of Goldsboro York County
Hammersly-Strominger House	Northeast of Lewisberry on PA 177, Lewisberry York County
Kise Mill Bridge	LR 66003 over Bennett Run, Woodside York County
Kise Mill Bridge Historic District	Address Restricted, York Haven York County

Table 2.11-1. Sites Listed in the National Register of Historic Places and Sites Determined Eligible for Listing that fall within a 6-mile Radius of TMI-1 (continued)

Site Name	Location
Sinking Springs Farms	Roughly bounded by Church Road, Sinking Springs Lane, North George Street, Locust Lane, Susquehanna Trail, and PA 238, Manchester York County
Sites Determined Eligible for Listing	
Haldeman Mansion	Township Road 839, Bainbridge Township Lancaster County
Goldsboro Historic District	Borough of Goldsboro, York County
Lewisberry Historic District	Roughly bounded by Lewis Street, City Unavailable York County
Newberrytown Historic District	Village of Newberrytown York County

Source: USDOI (2006)



Legend

- ☆ Three Mile Island Nuclear Station Unit 1
- Interstate
- Major Road
- Urban Area
- State Boundary
- County Boundary
- Water

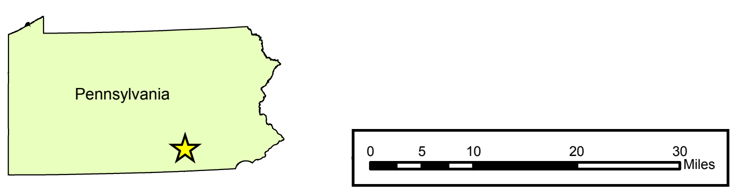


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Figure 2.1-1 50-Mile Vicinity Map

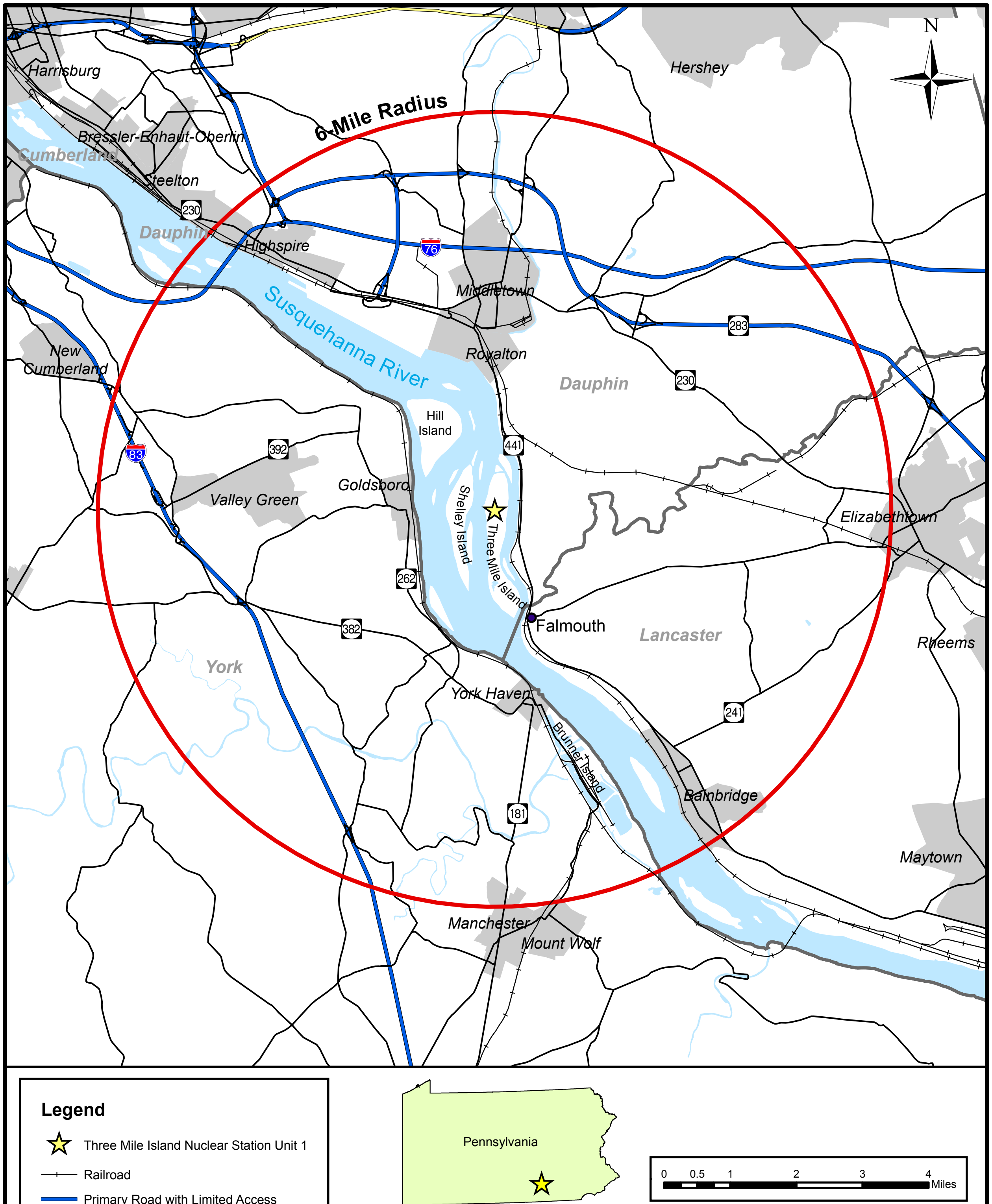

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Figure 2.1-2 6-Mile Vicinity Map

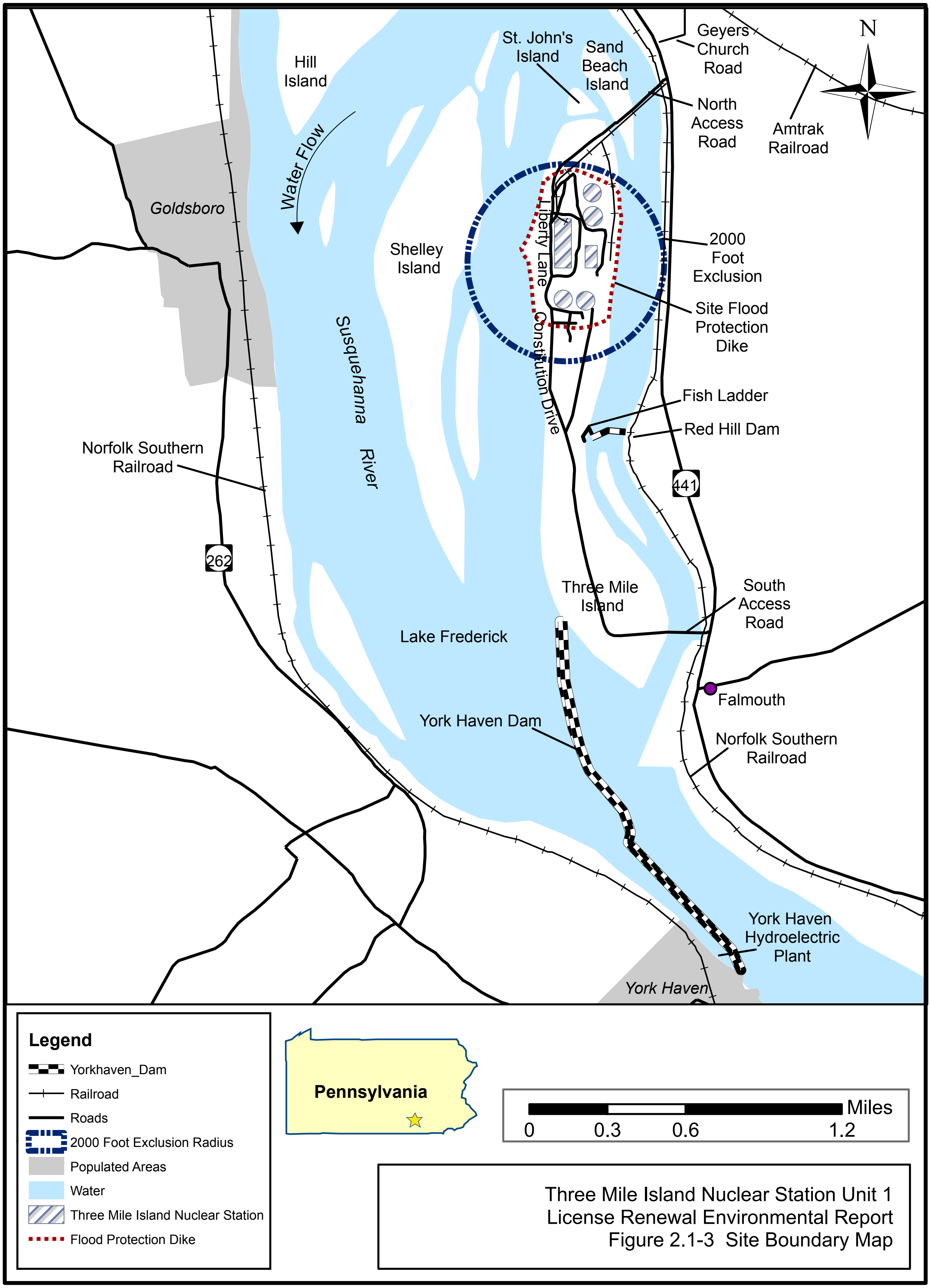

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Figure 2.1-3 Site Boundary Map

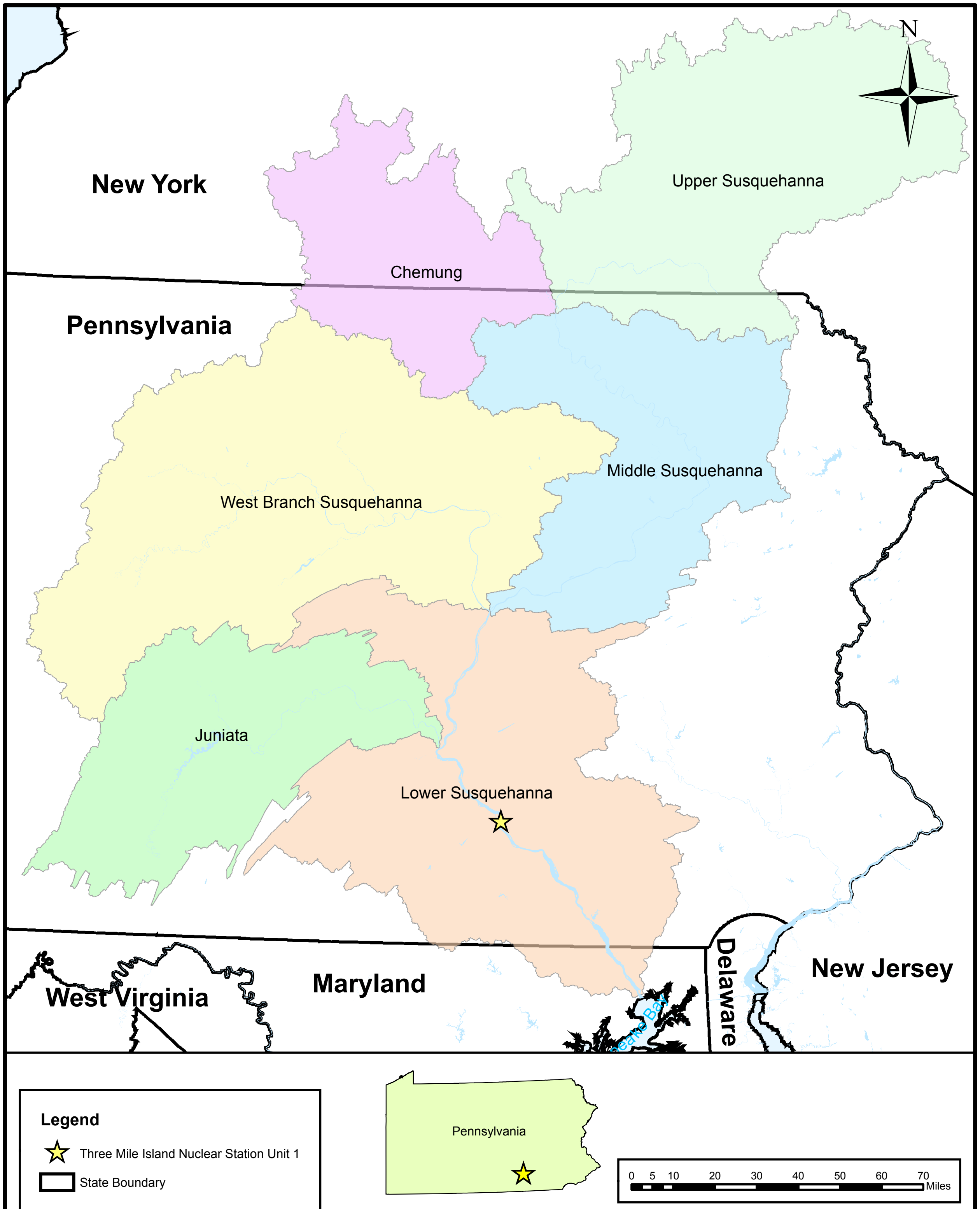

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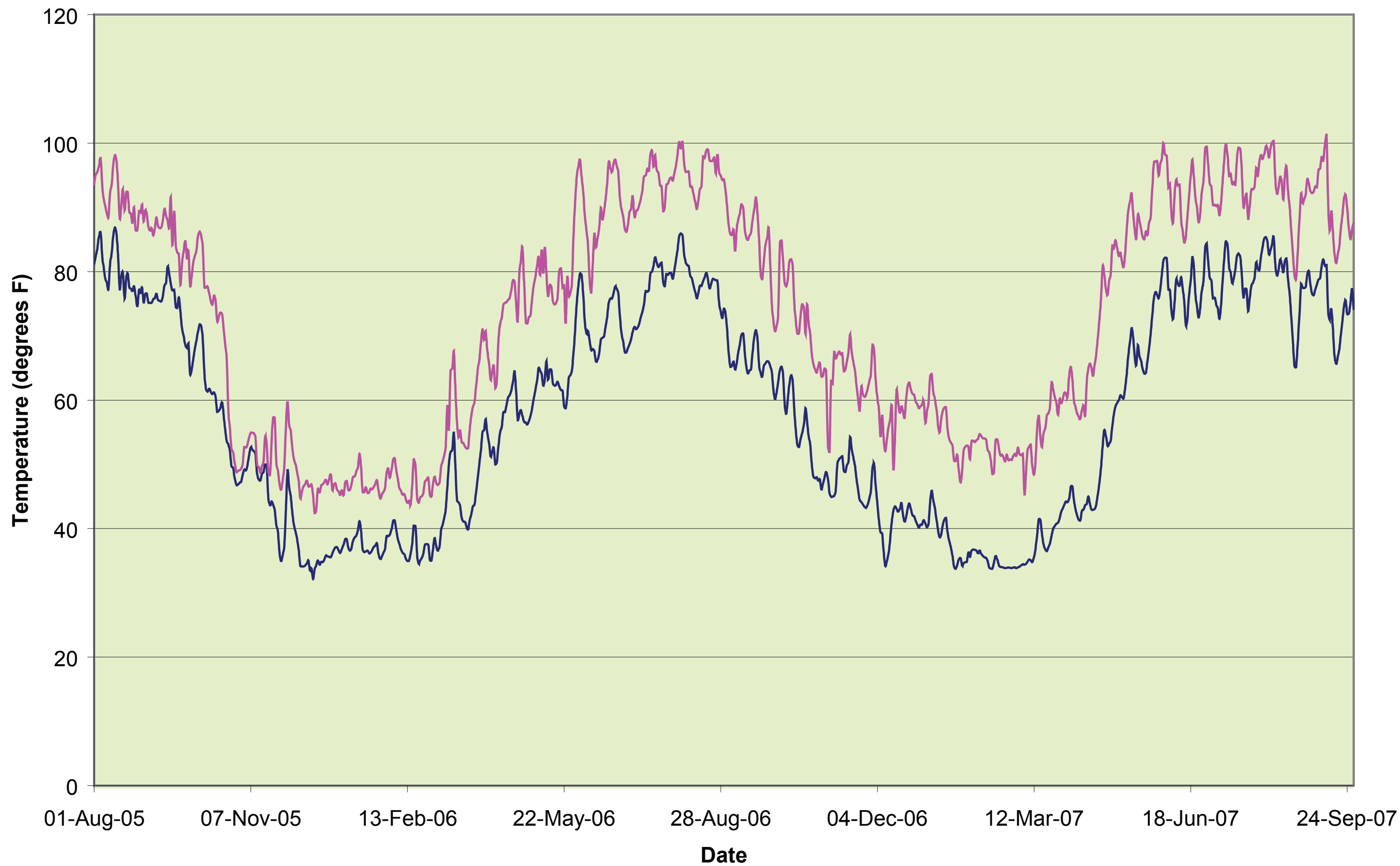
Figure 2.2-1 Susquehanna River Subbasins



LEGEND

Daily Average Inlet
Daily Average Discharge

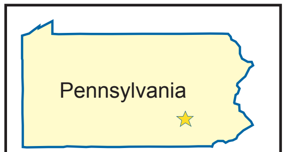


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Figure 2.2-2 TMI-1 Inlet and Discharge Temperatures

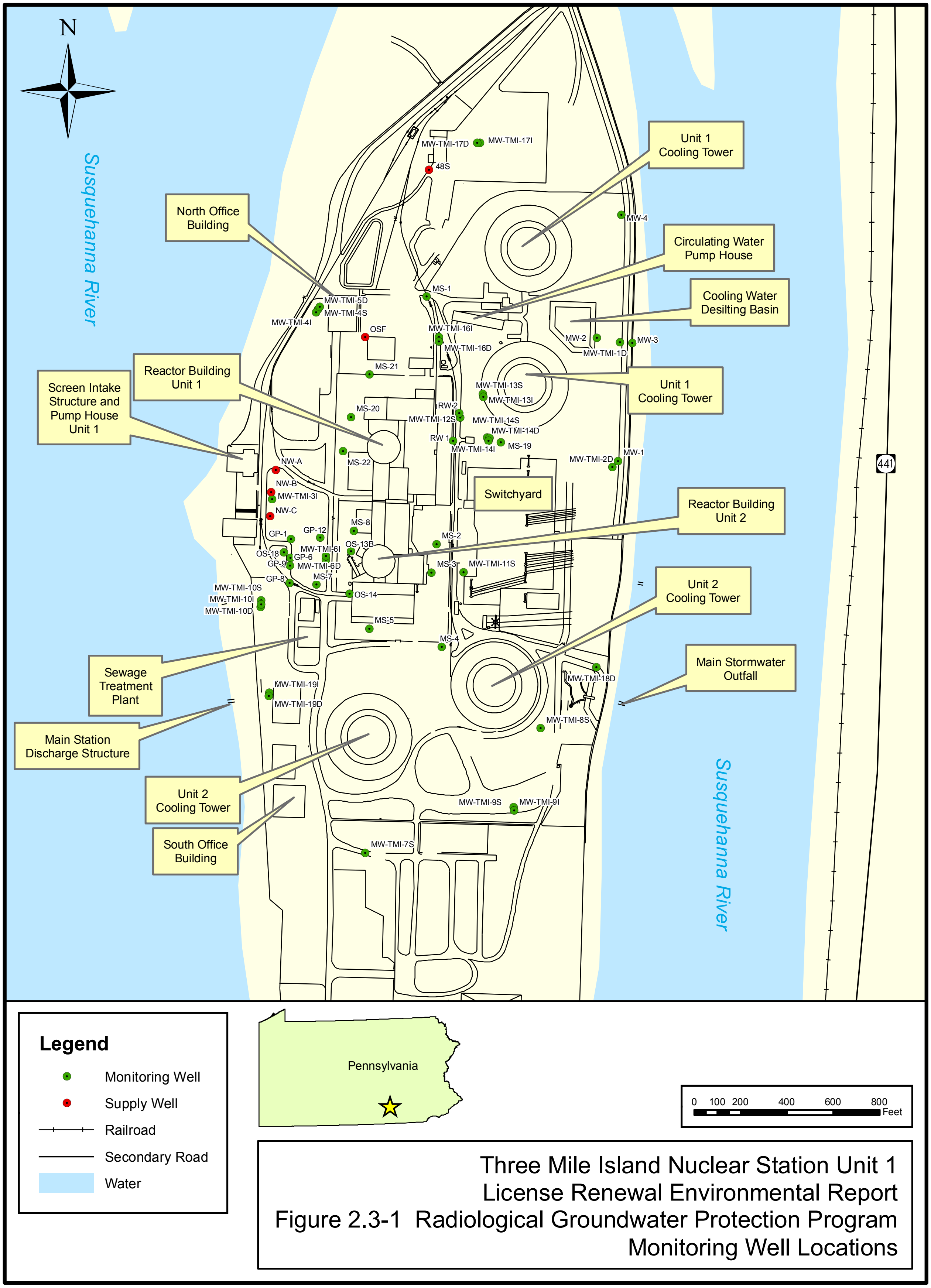

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Figure 2.3-1 Radiological Groundwater Protection Program
Monitoring Well Locations

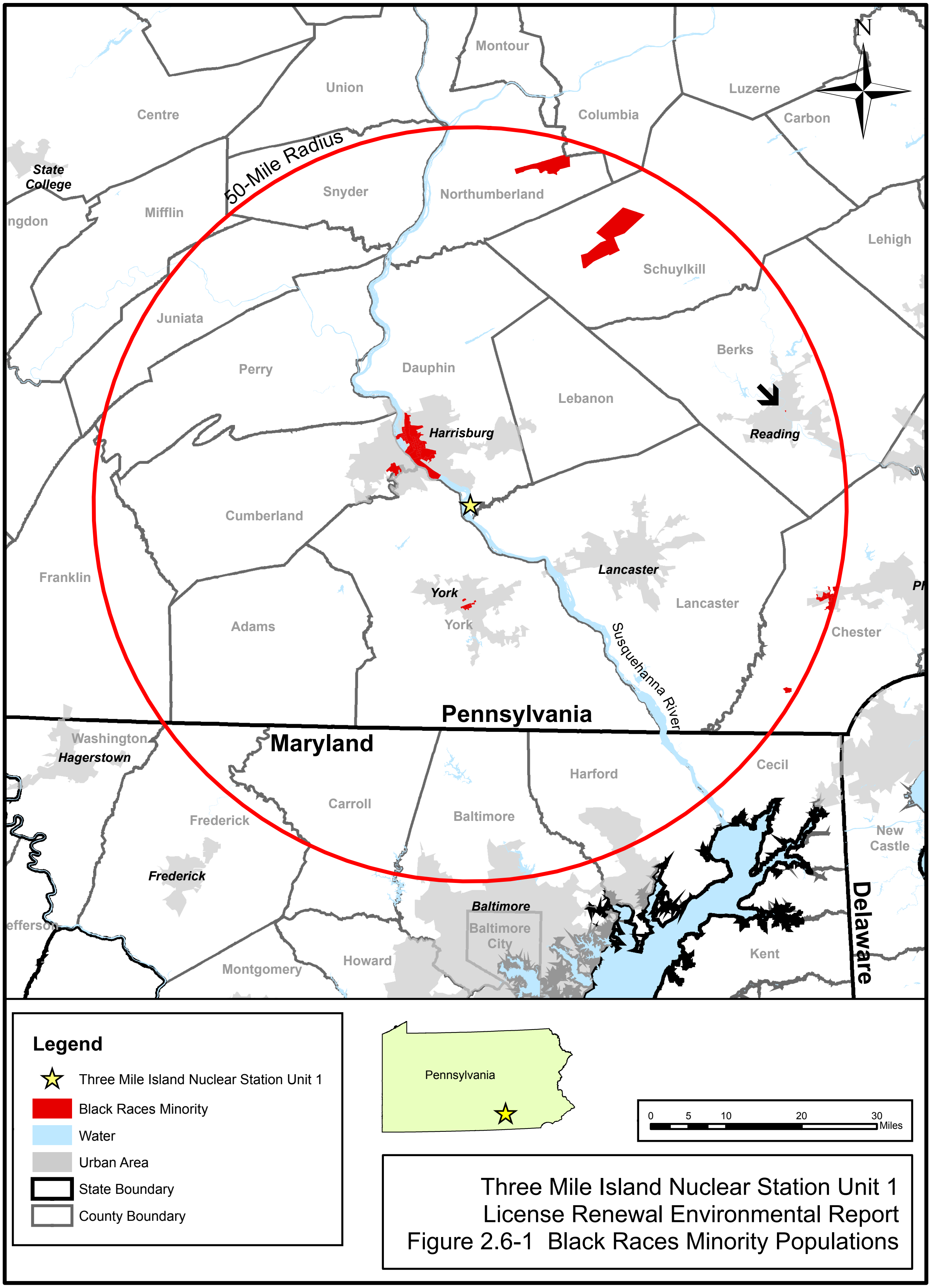

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Figure 2.6-1 Black Races Minority Populations

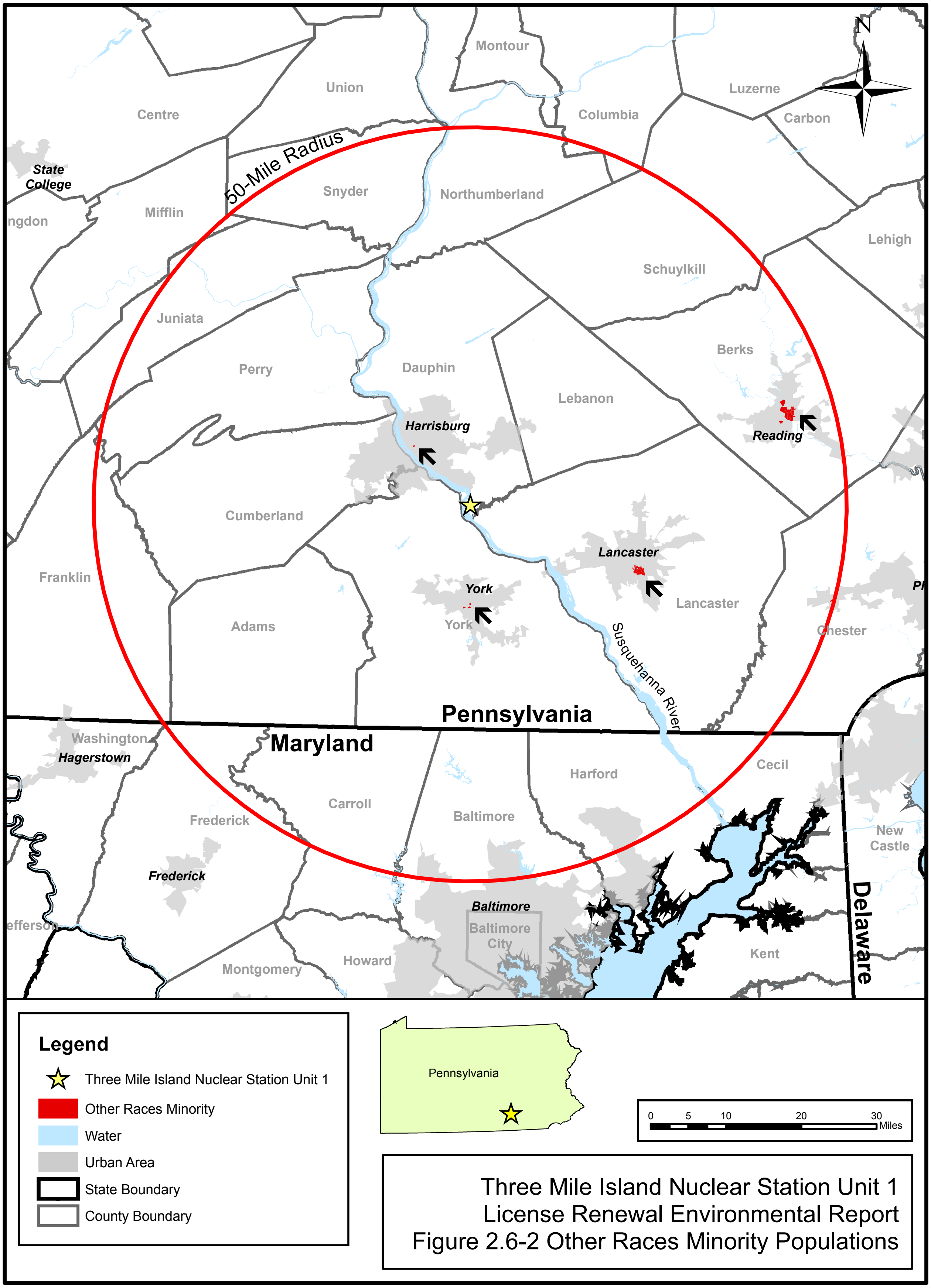

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Figure 2.6-2 Other Races Minority Populations

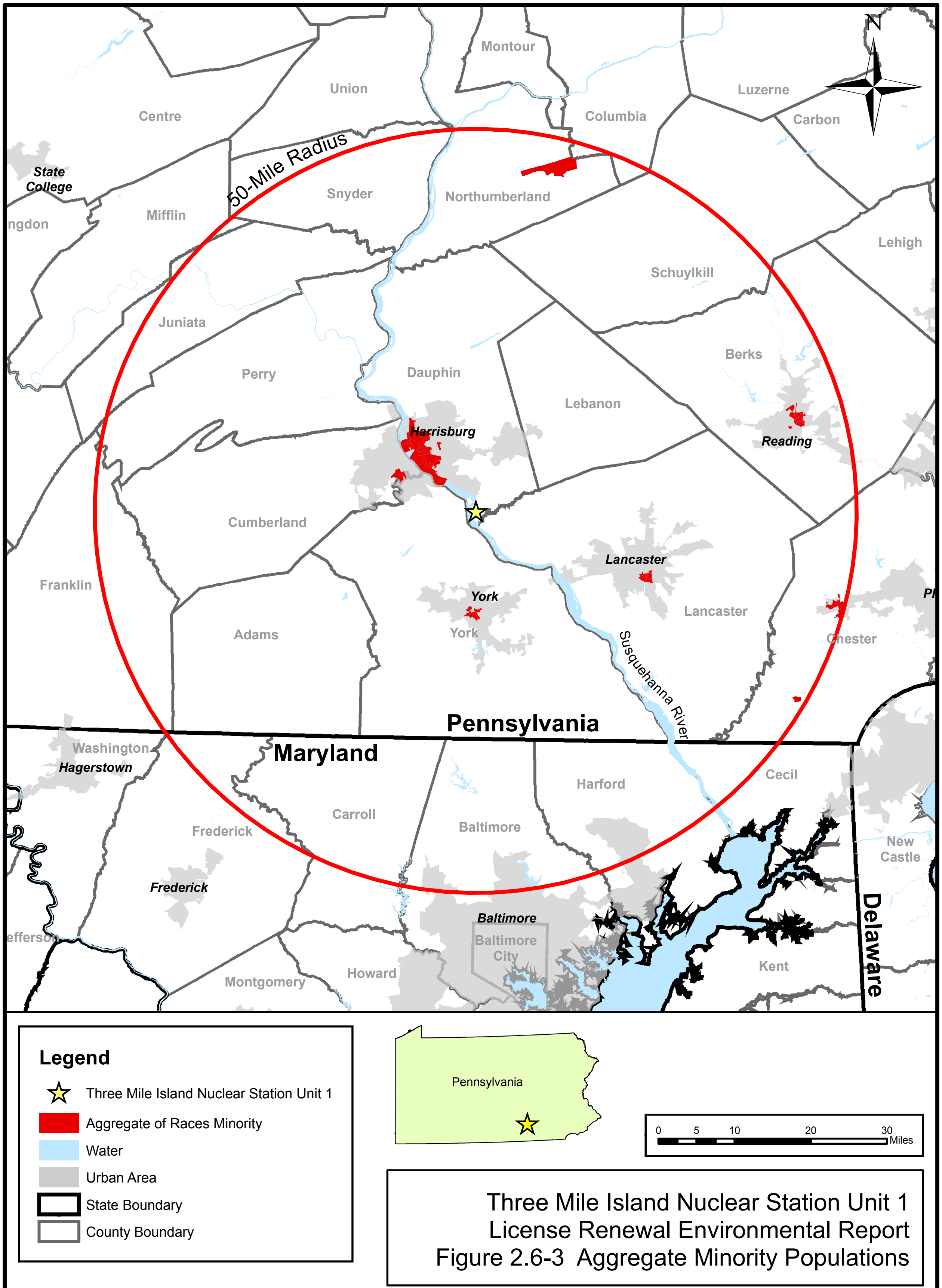

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Figure 2.6-3 Aggregate Minority Populations

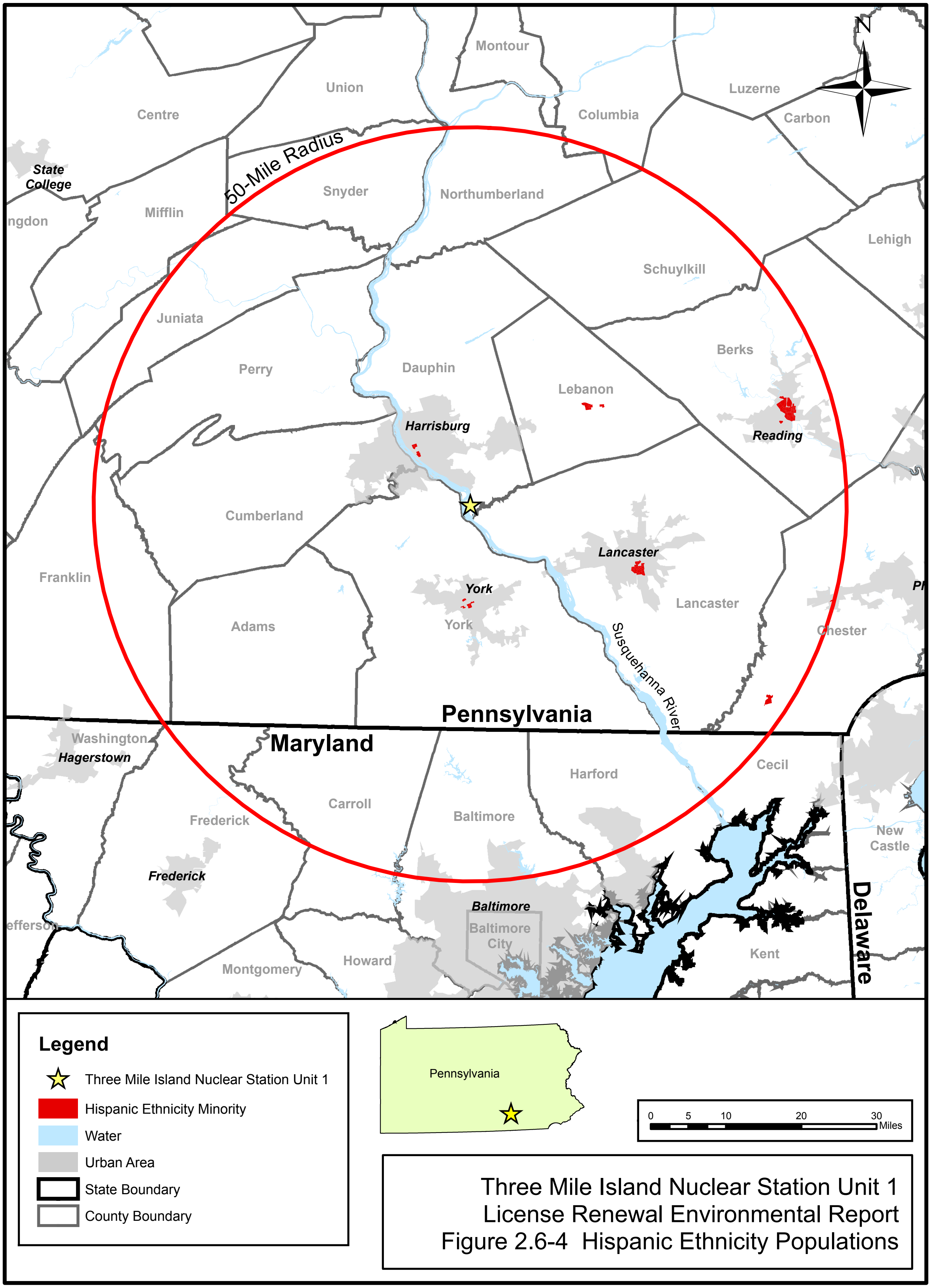

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Figure 2.6-4 Hispanic Ethnicity Populations

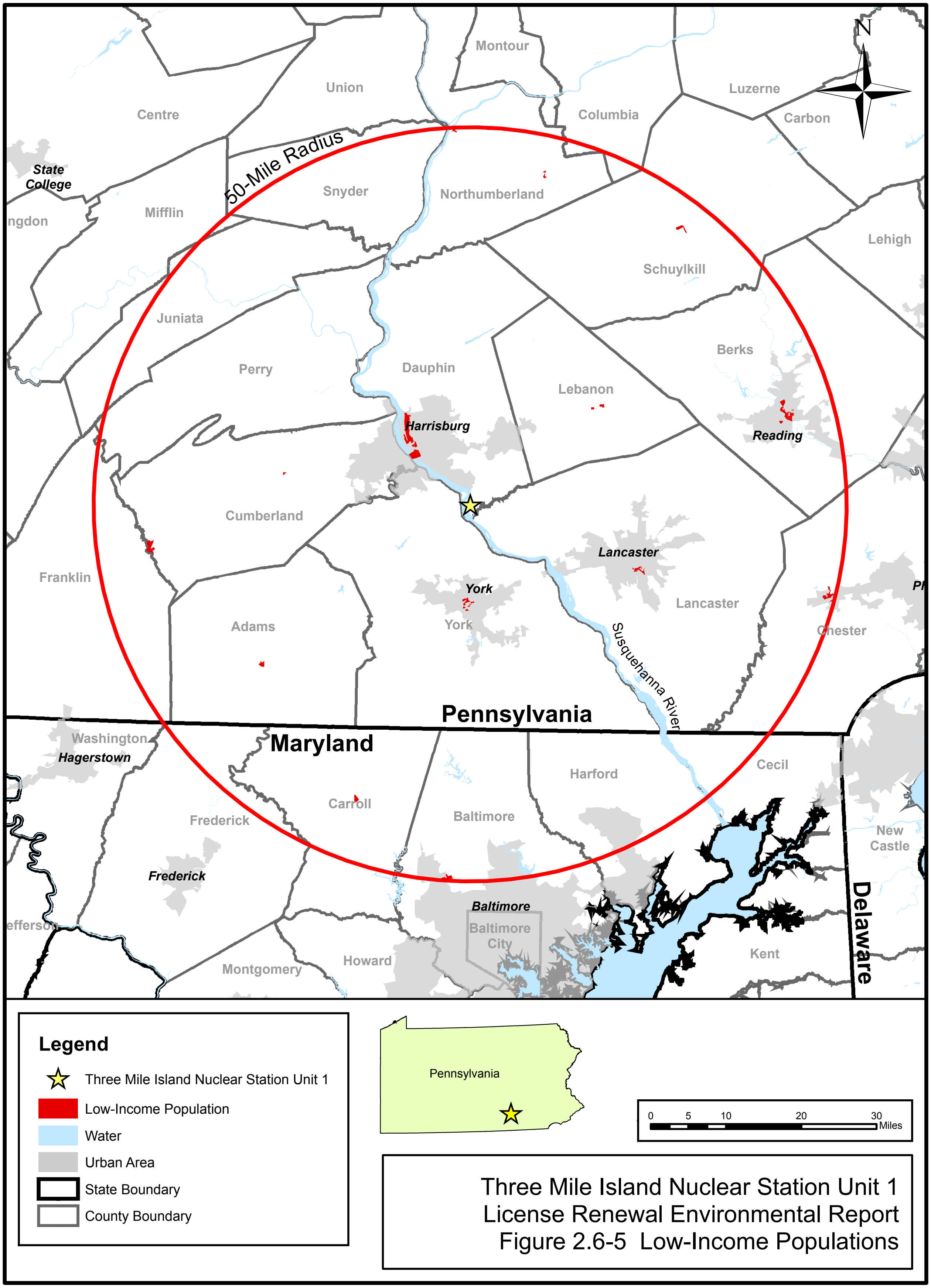

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Figure 2.6-5 Low-Income Populations

2.13 REFERENCES

Note to reader: Some web pages cited in this document are no longer available, or are no longer available through the original URL addresses. Hard copies of cited web pages are available in AmerGen files. Some sites, for example the census data, cannot be accessed through their given URLs. The only way to access these pages is to follow queries on previous web pages. The complete URLs used by AmerGen have been given for these pages, even though they may not be directly accessible. Also, all references are specific to respective chapter.

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Chapter 3

The Proposed Action

NRC

"…The report must contain a description of the proposed action, including the applicant's plans to modify the facility or its administrative control procedures…. This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment…." 10 CFR 51.53(c)(2)

AmerGen Energy Company, LLC (AmerGen) proposes that the Nuclear Regulatory Commission (NRC) renew the operating license for Three Mile Island Nuclear Station Unit 1 (TMI-1) for an additional 20 years. Renewal would give AmerGen and the Commonwealth of Pennsylvania the option of relying on TMI-1 to meet future electricity needs. Section 3.1 discusses the plant in general. Sections 3.2 through 3.4 address potential changes that could occur as a result of license renewal.

3.1 GENERAL PLANT INFORMATION

General information about TMI-1 is available in several documents. In 1972, the U.S. Atomic Energy Commission published the Final Environmental Statement (FES) related to the operation of Three Mile Island Nuclear Station Units 1 and 2 (AEC 1972). The Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) (NRC 1996) describes TMI-1 features and, in accordance with NRC requirements, AmerGen maintains the Final Safety Analysis Report for TMI-1 (AmerGen 2006a). AmerGen has referred to each of these and additional documents while preparing this environmental report for license renewal. Refer to Figure 3.1-1 for the general plant layout.

3.1.1 REACTOR AND CONTAINMENT SYSTEMS

TMI-1 is a pressurized water reactor (PWR) plant with a once through steam generator system. United Engineers and Constructors were the original plant construction contractors and Gilbert Associates was the architect-engineer. The nuclear steam supply system was supplied by Babcock and Wilcox. Commercial operation for TMI-1 began on September 2, 1974 (AmerGen 2006a). The initial core thermal power was 2,535 megawatts-thermal (MWt). The power rate was increased in July 1988 to 2,568 MWt following the seventh refueling outage (AmerGen 2006b).

The TMI-1 nuclear steam supply system consists of the reactor vessel, two vertical once through steam generators, four reactor coolant pumps, an electrically heated pressurizer, and interconnected piping. The steam generators are vertical, straight-tube-and-shell heat exchangers that produce superheated steam on their shell sides at a constant pressure over the power range. This design prevents fission products and activated corrosion products, which may be present in the reactor coolant water, from entering the steam used to drive the plant's turbines. Reactor coolant flows downward through the tubes and transfers heat to generate steam on the shell side. Within the shell, the tube bundle is surrounded by a cylindrical baffle. There are openings in the baffle at the feedwater inlet nozzle to afford contact feedwater heating. Emergency feedwater is supplied through an auxiliary feedwater ring located at the top of the steam generator to assure natural circulation of the reactor coolant following the unlikely event of the loss of all reactor coolant circulating pumps (AmerGen 2006a).

The primary containment is the reactor building and its associated isolation systems. The reactor building consists of a reinforced concrete slab and structure with cylindrical wall, a flat foundation mat, and a shallow dome roof. The 3-foot concrete cylindrical wall is prestressed with a post-tensioning system in the vertical and horizontal directions. The dome roof is prestressed using a three way post-tensioning system. The inside surface of the reactor building is lined with a carbon steel liner ¾ inch thick for the cylinder and dome and ¼ inch thick for the base (AmerGen 2006a).

The reactor fuel is sintered low-enriched uranium dioxide cylindrical pellets. The pellets are sealed in zirconium-based alloy tubing and caps. All fuel rods are internally prepressurized with helium (AmerGen 2006a).

The containment systems and their engineered safeguards are designed to ensure that offsite doses resulting from postulated accidents are well below the guidelines in 10 CFR 100, *Reactor Site Criteria*.

3.1.2 COOLING AND AUXILIARY WATER SYSTEMS

At TMI-1, the Circulating Water System and service water systems draw from the Susquehanna River and cooling tower blowdown is discharged to the same river downstream from the intake structure. Onsite groundwater wells are also utilized for cooling water makeup, domestic water consumption, and other industrial purposes. The following subsections describe the water systems at TMI-1.

3.1.2.1 Surface Water

TMI-1 has a permit with the Susquehanna River Basin Commission for consumptive use of river water up to 18 million gallons per day, on a 30 day average, for electric generation. To comply with permit requirements, TMI-1 participates in the Cowanesque Reservoir water allocation project, which will allow discharge of stored water in the event of a drought condition protecting TMI-1 from a shutdown during a drought emergency in the Susquehanna River (McLaren/Hart 1998).

The TMI-1 Intake Screen and Pump House (ISPH) structure is located on the western bank of the island. The ISPH structure houses plant river water pumps that take suction from the Susquehanna River (AEC 1972).

3.1.2.2 Circulating Water System

TMI-1 utilizes two hyperbolic natural draft cooling towers for dissipating the heat rejected from the plant steam cycle. In addition to this major heat load, there are several other cooling systems that dissipate heat from other portions of the plant. The condensing equipment consists of a single-pass main condenser and two-pass units for the auxiliary condensers. Makeup water for cooling tower evaporation, wind loss, and blowdown are obtained from the Open Cycle Cooling Water System. River water used in the Circulating Water System enters the intake structure, passes under a skimmer wall, through automated trash racks with 1-inch vertical bar spacing, through traveling screens with 3/8-inch mesh, through the river water pumps, and finally through strainers of 1/8-inch mesh before passing to the heat exchangers. The intake structure is also equipped with a deicing line for operation during subfreezing weather. After passing through the secondary services coolers, river water is mixed with circulating water in the circulating pumps. The flow velocity at the Intake Structure under normal operating conditions is 0.2 feet per second. The maximum withdrawal of makeup water for cooling tower losses is 15,250 gallons per minute (gpm). Under normal operations, approximately 12,250 gpm is withdrawn. The circulating water pump building contains six circulating water pumps that are arranged so three pumps discharge water into each of the 102-inch-diameter mains. The Circulating Water System is equipped with a chemical injection system for controlling bacterial and algae growth and corrosion. Cooling tower blowdown at a normal rate of 3,000 gpm (maximum of 6,000 gpm) is combined with the Open Cycle Cooling Water and discharged to the Susquehanna River through a 48-inch-diameter river discharge line. The intake water pumping systems are designed to pump under three river conditions: (1) loss of the York Haven Dam; (2) the normal river elevation of 278 foot; and (3) flood levels. (AmerGen 2006a, 2007).

3.1.2.3 Groundwater Resources

To reduce operations and maintenance costs at TMI-1 associated with clarifying river water in the Pre-Treatment System, three groundwater service wells, (A, B, and C), were installed in 1996 to supplement industrial water withdrawn from the Susquehanna River (Figure 3.1-1). The groundwater is used for station fire service, makeup to the demineralized water system, bearing lubrication for the screen house pumps, and service water for other buildings and equipment (McLaren/Hart 1998).

There are two drinking water wells, (OSF and 48S), located north of the TMI-1 reactor building. The drinking water treatment system is permitted by the Pennsylvania Department of Environmental Protection. Dilute orthophosphate solution can be added to the drinking water by an automatic pump system at each well house. Zinc orthophosphate solution is added to the system to control corrosion and reduce concentrations of lead and copper. Sodium hypochlorite solution is periodically added as a biocide. If it is not needed to supply drinking water, the OSF well may be used to augment the supply of service water from wells A, B, and C (McLaren/Hart 1998).

AmerGen operates a sanitary wastewater treatment facility with a design capacity of 80,000 gpd (gallons per day). The typical daily flow at the facility is between 10,000 and 15,000 gpd. However, during outages the maximum flow approaches 40,000 gpd. The facility is adequately sized to meet all projected outages.

3.1.3 TRANSMISSION FACILITIES

The Updated Final Safety Analysis Report (AmerGen 2006a) identifies four 230-kilovolt (kV) transmission lines that connect TMI-1 to the electric grid. Two of these lines connect the plant with the existing substation at Middletown Junction, east of the Susquehanna River. Each of these lines extends for 1.5 miles. A third line extends for 4.1 miles to the west side of the Susquehanna River, where it connects to a 230-kV line terminating into Jackson Substation.

The fourth 230-kV line extends to the TMI-1 500-kV Substation. Inside the substation the voltage is converted to 500-kV with a 230/500-kV autotransformer, which is connected to the FirstEnergy 500-kV grid.

Figure 3.1-2 is a map of the TM-1I transmission system.

- Line No. 1091 – TMI-1 to Middletown Junction – This 230-kV line operated by FirstEnergy Corporation extends northeast for 1.5 miles in a 150-foot wide corridor to the Middletown Junction Substation near Middletown.
- Line No. 1092 – TMI-1 to Middletown Junction – This 230-kV line operated by FirstEnergy Corporation extends northeast for 1.5 miles in a 150-foot wide corridor to the Middletown Junction Substation near Middletown.
- Line No. 1051 – TMI-1 to Jackson Substation – This 230-kV line operated by FirstEnergy Corporation extends southward for 4.1 miles in a 150-foot wide, arcing corridor to the Jackson Substation near Jackson, west of the Susquehanna River.
- Line from TMI-1 to the 500-kV Substation – This 230-kV line shares the first four towers with the TMI-1 to Jackson Substation line. The line extends southeast for 0.7 miles and connects to the 500-kV Substation.

In total, the transmission lines of interest to Section 4.13 are contained in approximately 5.6 miles of corridor that occupy approximately 142 acres. The TMI-1 to Middletown Junction lines has adjacent corridors. The corridors pass through land that is primarily agricultural or forested, but also pass over residential and urban areas. The areas are mostly remote with low population densities. Corridors that pass through pastures generally continue to be used as pastures. Each of the lines crosses State Route 441 after leaving the switchyard. The TMI-1 to Jackson Substation Line also crosses several smaller roads. FirstEnergy Corporation owns and operates these transmission lines, which connect TMI-1 to the PJM regional transmission system. These transmission lines would remain under FirstEnergy's ownership and would most likely stay in service after TMI-1 is decommissioned.

The transmission lines were designed and constructed in accordance with the National Electrical Safety Code (for example, IEEE 1997) and other industry guidance that was current when the lines were built. Ongoing surveillance and maintenance of these transmission facilities ensure continued conformance to design standards. These maintenance practices are described in Section 4.13.

3.1.4 WASTE MANAGEMENT AND EFFLUENT CONTROL SYSTEMS

3.1.4.1 Radioactive Waste

TMI-1 radioactive waste (radwaste) systems are designed and constructed to contain, control, and release or dispose of radioactive byproducts generated as a result of normal and emergency operation of the plant. The byproducts are activation products resulting from the irradiation of reactor cooling water and impurities therein (principally metallic corrosion products) and fission products resulting from defective fuel cladding or uranium contamination within the reactor coolant system. Table 3.1-1 contains a list of the radwaste systems at TMI-1.

The liquid waste disposal system, the waste gas system, and the solid waste disposal and packaging system are described more fully below. These descriptions, unless otherwise specified, are derived from Chapter 11, "Radioactive Waste and Radiation Protection," in the TMI-1 *Updated Final Safety Analysis Report* (i.e., AmerGen 2006a).

Radioactive Liquid Waste Disposal System

The radioactive liquid waste disposal system provides operating service functions to the reactor coolant system and spent fuel pool, allowing recovery of concentrated boric acid and purified water from the reactor coolant, the refueling water, and the spent fuel pool water. In addition, the radioactive liquid waste disposal system collects, contains, and processes miscellaneous wastes for reuse and disposal. Such wastes include wastes from laboratory drains, wastes from building drains and sumps, wastes from equipment drains and sumps, wastes from regeneration of deborating resins, spent resins from demineralizers, used precoat from precoat filters, potentially radioactive wastes from showers and the laundry, and potentially radioactive oil.

The major equipment components of the liquid waste disposal system are tanks, pumps, precoat filters, demineralizers, evaporators, coolers, and floor and equipment drains with associated sumps and piping. Except for potentially radioactive oil, radioactive liquid wastes are (1) routed through evaporators and demineralizers, (2) collected in the waste evaporator condensate storage tanks, and (3) either reused or discharged into the effluent from the cooling water basin, which is released to the Susquehanna River pursuant to the TMI-1 technical specifications and NPDES permit. Releases of liquid radwaste to the river are on a batch basis with activity analyses (including an isotopic breakdown) being performed for each batch prior to release. A minimum cooling water effluent flow rate of 5,000 gpm is maintained from the open-cycle cooling water system during releases. The actual cooling water flow rate during each individual batch release is determined based on the activity analyses for the liquid radwaste in the batch. The flow rate during a batch release is controlled to ensure that the activity in the discharge does not exceed the specifications in the TMI *Offsite Dose Calculation Manual* (AmerGen 2006c).

Discharges of liquid radwaste to the Susquehanna River are initiated in accordance with strict administrative procedures. The liquid radwaste is combined with open-cycle cooling water in a mixing chamber before being discharged to the river. The mixture enters the river approximately 600 feet downstream from the river water intake structure.

Concentrated wastes are collected in storage tanks and managed in the solid waste packaging and disposal system.

Potentially radioactive oil is collected in a 700-gallon tank. Depending on the results of tank sampling, the oil may be drained from the tank, solidified (see the discussion below describing the solid waste packaging and disposal system), and managed as low-level radioactive waste. Alternatively, it may be managed as non-radioactive waste oil.

Waste Gas System

The radioactive waste gas system collects and stores gases that emanate from reactor coolant water in tanks and equipment where such gases may accumulate. The system design provides a blanket of inert nitrogen gas in which to collect such gases. These gases consist primarily of hydrogen with small amounts of gaseous fission products and activated dissolved gases. The gas mixture (i.e., nitrogen, hydrogen, and radioactive gases, including isotopes of krypton, xenon, and iodine) collected in the radioactive waste gas system is compressed and stored for decay of the radioactive components prior to release to the atmosphere.

During normal operation, three waste gas decay tanks each provide a 30-day minimum storage period for radioactive decay before the gases they contain are released to the atmosphere. Each tank is filled until it reaches 80 psig, which is the design discharge pressure for the waste gas system compressors. At 80 pounds per square inch (psig), an automatic sequencing system preferentially selects a new waste gas decay tank for filling based on tank pressures and whether gases are discharging from other available tanks at that time. The tanks are each equipped with a relief valve that activates if tank pressure exceeds 85 psig. The design pressure of the high-pressure waste gas system piping and other components is 150 psig. Consequently, rupture and major failure resulting from overpressure of piping and other components of the high-pressure portion of the waste gas system are not considered credible. Accidental discharges resulting from the relieving of a waste gas decay tank or compressor relief valve also are not considered credible because the operator would have approximately 8 minutes between receipt of the alarm that the automatic sequencer had not transferred waste gas flow to a fresh tank and activation of the relief valve on the overfilled tank. This time is considered sufficient for the operator to either bring an alternative tank on-line or terminate gas flow into the vent header system.

Shortly after a tank is full (i.e., it has been filled to 80 psig), the compressed waste gases within the tank are sampled and analyzed. Administrative approval, based on the results of such analyses, is required before initiating release to the atmosphere of the waste gases stored in the tank. When stored gas is to be released, double monitoring prior to the release is required to assure compliance with the exposure limits at the site boundary, as established in 10 CFR 20, "Standards For Protection Against Radiation," and to verify compliance with 10 CFR 50, Appendix I, "Numerical Guides For Design Objectives And Limiting Conditions For Operation To Meet The Criterion 'As Low As Is Reasonably Achievable' For Radioactive Material In Light-Water-Cooled Nuclear Power Reactor Effluents."

Radioactive Solid Waste Packaging and Disposal System

Radioactive solid wastes being shipped off-site from TMI-1 fall into five general categories:

- Concentrated liquid waste (evaporator bottoms)
- Used precoat (spent powdered resin)
- Spent resin (bead type)
- Dry compactable trash
- Dry non-compactable trash

Dry compactable trash is either compacted on site (to reduce volume), or shipped to an offsite processor for decontamination and/or compaction prior to recycle or disposal.

An on-site radioactive waste solidification system using cement is available to solidify concentrated liquid wastes. The solidification is accomplished by pumping the quantity of waste to be solidified into a lined shipping container that has an internal mixer associated with the liner. The mixer is started and cement is added. Mixing continues until the mixer motor current increases, which indicates that the mixture is beginning to set. Following visual and tactile verification of solidification, the liner and container are closed and either temporarily stored or transported to a licensed low-level radioactive waste disposal facility. The U.S. Department of Transportation (DOT) has approved pre-shielded containers of this type for shipping low-level radioactive wastes.

Depending on applicable regulatory requirements, used precoat and spent resins may also be solidified using the radioactive waste solidification system. Like the concentrated liquid wastes, these solidified wastes are also packaged in pre-shielded DOT-approved containers, temporarily stored on site until being shipped to a licensed low-level radioactive waste disposal facility.

When the regulations do not require that evaporator bottoms, used precoat, or spent resin be solidified, such wastes are properly dewatered, packaged directly into DOT-approved containers (without solidification), and temporarily stored until transported to a licensed, off-site processor for volume reduction and/or disposal in low-level radioactive waste disposal facility.

If waste oil is sufficiently contaminated with radioactive material, it too is managed in the radioactive waste solidification facility.

3.1.4.2 Nonradioactive Waste

Nonradioactive waste is produced from plant maintenance, cleaning and operational processes. The majority of the nonradioactive waste generated at TMI-1 consists of process wastewater and nonhazardous plant trash. Other nonradioactive industrial wastes generated at TMI-1 include discarded surface coatings, glycols/antifreeze, spent oil filters, grease, oil-contaminated soil and debris, nonhazardous waste oil, and other chemical wastes. Universal wastes, such as spent fluorescent bulbs and batteries common to any industrial facility are also generated at TMI-1.

Nonradioactive wastes classified as hazardous under Subtitle C of the Resource Conservation and Recovery Act routinely make up a very small percentage of the total wastes generated at TMI-1. Such wastes include spent and off-specification (e.g., shelf life expired) chemicals, laboratory chemical wastes, and occasional project-specific wastes. Because it generates less than 100 kilograms per month of these wastes, TMI-1 is categorized as a small quantity generator of hazardous waste under federal and state regulations (40 CFR 62, “Standards Applicable to Generators of Hazardous Waste”; 25 PA Code 262a).

3.2 REFURBISHMENT ACTIVITIES

NRC

"The report must contain a description of … the applicant's plans to modify the facility or its administrative control procedures as described in accordance with § 54.21...This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment…." 10 CFR 51.53(c)(2)

"The environmental report must contain analyses of …refurbishment activities, if any, associated with license renewal…" 10CFR51.53(c)(3)(ii)

"…The incremental aging management activities carried out to allow operation of a nuclear power plant beyond the original 40-year license term will be from one of two broad categories…(2) major refurbishment or replacement actions, which usually occur fairly infrequently and possibly only once in the life of the plant for any given item...." (NRC 1996, Section 2.6.3.1)

NRC regulations at 10 CFR 51 do not define a "refurbishment activity," but Section 2.6.2.6 in the GEIS explains that, for the purpose of license renewal, refurbishment activities encompass actions that typically take place only once in the life of a nuclear plant, if at all (NRC 1996). Examples of refurbishment activities provided in this GEIS section include pressurized water reactor steam generator replacement, if it would not have to be performed during the current license term, but is elected by the licensee to enable safe and economic operation for the incremental term allowed with license renewal. Because the situation at TMI-1 is consistent with this example, AmerGen is analyzing steam generator replacement in this environmental report as a refurbishment activity, pursuant to 10 CFR 51.53(c)(3)(ii).

AmerGen plans to replace the two TMI-1 steam generators with enhanced once-through steam generators. Replacement activities are expected to last approximately 70 days and be conducted sometime between October 2009 and date on which the existing operating license expires.

Each steam generator consists of straight-tube heat exchangers that convert heat from the reactor coolant system into steam to drive the turbine generators and produce electricity. The straight-tubes in the original steam generators are made of alloy 600MA. This alloy degrades over time as a result of a variety of corrosion and mechanical factors. Alloy 600MA degradation affects both of the steam generators at TMI-1. Accordingly, AmerGen has determined that they should be replaced with steam generators that use alloy 690TT tubing material, which has improved resistance to stress corrosion cracking.

The replacement steam generators will be dimensionally equivalent to the original steam generators, with the incorporation of numerous design enhancements that will minimize the number of pressure vessel welds, thereby improving inspectability. In conjunction with the steam generator replacement, the hot leg elbows, portions of the piping, and all existing steam generator insulation will be replaced. The steam generator blowdown system capacity also will be increased. Most of these activities would be performed inside existing structures.

The replacement steam generators will be manufactured in Chalon/St Marcel, France by Areva NP and transported to TMI-1. The transport is expected to involve the following steps:

- River transport from the Areva NP St Marcel plant to Fos S/Mer harbor (near Marseille).

- Ocean transport from Fos S/Mer harbor to a U.S. port of call, which may be Baltimore, Newark, or Philadelphia.

- A combination of barge, rail, and/or road transport from the U.S. port of call to TMI-1, using one of the following options:

  - Barge from Baltimore, MD through the Chesapeake Bay and up the Susquehanna River to Port Deposit, MD. Then, rail or road to TMI-1;

  - Rail and/or road from Baltimore, MD to TMI-1;

  - Rail and/or road from Philadelphia, PA to TMI-1;

  - Rail and/or road from Newark, NJ to TMI-1.

A vendor will be selected to perform a detailed transportation study that will be the basis for establishing the final transportation plan in June 2008. Regardless of which option is selected for transporting the replacement steam generators within the U.S., all federal, state, and local requirements would be met for associated activities, which may include any or all of the following:

- Dredge or fill activities;

- Temporary or permanent removal of interferences, such as narrow tunnels and low-hanging overhead lines; and

- Movement of wide and heavy loads over railways and roadways.

Once the replacement steam generators arrive at TMI-1, they will be transported on-site by a self-propelled modular transporter. Each replacement steam generator would be loaded onto a heavy-duty self-propelled modular transporter and moved to a steam generator storage facility (described below) that will be constructed at TMI-1 (Figure 3.1-1).

To perform the steam generator replacement, a temporary opening approximately 26 feet by 25 feet will be created in the containment building directly above the existing equipment hatch. The containment building is composed of reinforced concrete walls over three feet thick with an interior steel liner and is tensioned with horizontal and vertical tendons (AmerGen 2006a). The process of creating the opening will include activities such as de-tensioning and removing tendons, removing concrete, cutting rebar, and cutting and removing a section of the steel liner. A hydro-demolition (high pressure water) process and other mechanical methods will be used to remove the concrete and cut the liner. After steam generator replacement, the opening will be sealed and the containment building returned to its original configuration and integrity.

The two original steam generators will be removed from the containment building through the temporary opening. First, however, they must be drained and cut away from existing piping and supports. Steel covers would be seal-welded to the nozzles of main coolant, steam, and feedwater piping openings of the original steam generators to seal off internal sections. Loose contamination would be removed from the exterior of each original steam generator and a coating would be applied to affix any remaining contamination.

Once removed from the containment building, the original steam generators will be transported to the new steam generator storage facility. Meanwhile, the replacement steam generators will be removed from the storage facility and moved to the vicinity of the TMI-1 containment building. Installation would include construction of supports, connection of piping, and testing of system integrity.

Site planning, construction of facilities, modification of existing buildings, and other preparation activities will occur at TMI-1 prior to removal of the original steam generators from the TMI-1 containment building. The only new permanent facility will be the new steam generator storage facility. Temporary facilities for offices, fabrication activities, mock-up activities, weld testing, warehouse areas, and lay down areas will be used. A 4,500 square foot fabrication/weld test shop would be erected between the south flood dike and the vehicle barriers east of the gas bottle storage building. While the building would be removed following the project, the concrete floor slab at grade will remain. A 6,000 square foot decontamination facility will be located across the road from the TMI-1 intake structure. A slab will not be poured for this building so it will be removed in its entirety after the steam generators have been replaced. All other temporary facilities will either use portions of existing TMI-1 structures and facilities or will consist of temporary structures located within the developed industrial area of the site.

AmerGen estimates that the total area disturbed by construction, decontamination, and laydown activities would be less than 10 acres, all of which would be previously disturbed property within the bounds of the TMI-1 flood protection dike. The small amount of disturbed area and implementation of best management practices (e.g., watering, silt fences, covering soil piles, hydro-demolition, etc.) would minimize the amount of fugitive dust generated by refurbishment activities.

Construction activities would result in noise levels (primarily from hydro demolition) greater than those associated with normal TMI-1 operation. Noise from construction activities would be intermittent and temporary in nature, and would decrease as the distance from the source increases.

The peak period of activity would occur when the actual removal and replacement of the steam generators take place. AmerGen anticipates that up to 900 additional workers would be on site at that time. In comparison, 1,400 additional workers are required for a regular refueling outage.

AmerGen has determined that the most cost effective method for managing the original steam generators is to store them on site in a dedicated storage facility and then disposition them along with the remaining plant equipment when TMI-1 is decommissioned. The steam generator storage facility would consist of a 6,000 square foot building with approximate dimensions of 100 feet long by 60 feet wide by 30 feet high. The building would be located within the flood dike, which is part of the previously disturbed, developed industrial area of the site (Figure 3.1-1).

The steam generator storage facility would be designed in accordance with State and Local building codes, and would consist of a reinforced concrete structure constructed on a reinforced concrete mat foundation. The design would include a watertight roof membrane or equivalent roofing system. Design and construction would preclude moisture intrusion through construction joints, the roof membrane, and wall closures. The front wall would consist of precast concrete panels installed after the original steam generators have been placed inside the building. The building materials will provide sufficient shielding to ensure dose rates remain within acceptable regulatory limits in accordance with 10 CFR 20, *Standards for Protection Against Radiation.* Construction of the steam generator storage facility will include the following activities:

- Obtaining required permits and approvals;
- Excavation for the structure and utilities;
- Installation of utilities and construction of the foundation slab, walls, and roof; and
- Backfill, grading, and paving around the completed structure.

AmerGen anticipates that up to 50 workers would be required for construction of the facility.

3.3 PROGRAMS AND ACTIVITIES FOR MANAGING THE EFFECTS OF AGING

NRC

"…The report must contain a description of … the applicant's plans to modify the facility or its administrative control procedures…. This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment…." 10 CFR 51.53(c)(2)

"…The incremental aging management activities carried out to allow operation of a nuclear power plant beyond the original 40 year license term will be from one of two broad categories: (1) SMITTR actions, most of which are repeated at regular intervals …." NRC 1996 (SMITTR is defined in NRC 1996 as surveillance, monitoring, inspections, testing, trending, and recordkeeping.)

In accordance with 10 CFR 54.21, programs and inspections for managing aging effects at TMI-1 are described in the Three Mile Island Nuclear Station License Renewal Application, Appendix B, Aging Management Programs and Activities.

Other than implementation of these programs and inspections, there are no planned modifications of TMI-1 administrative control procedures associated with license renewal.

3.4 EMPLOYMENT

Current Work force

AmerGen employs approximately 525 permanent employees and 170 long-term contract employees at TMI-1. The permanent staff at a nuclear plant with one reactor normally ranges between 600 and 800 employees (NRC 1996). Approximately 71 percent of the employees live in Dauphin and Lancaster Counties, Pennsylvania. The remaining employees are distributed across 14 counties in Pennsylvania, with numbers ranging from 1 to 57 employees per county. There are about five employees that live outside of Pennsylvania (see Table 2.6-1).

TMI-1 is on a 24-month refueling cycle. During refueling outages, site employment increases above the permanent work force by as many as 1,400 workers for approximately 20 to 30 days of temporary duty. This number of outage workers falls outside of the range (200 to 900 workers per reactor unit) reported in the GEIS for additional maintenance workers (NRC 1996), but for a relatively short period of time (approximately three weeks).

Refurbishment Increment

Performing the refurbishment activities described in Section 3.2 would necessitate increasing the TMI-1 staff workload by some increment. The size of this increment would be a function of the schedule within which AmerGen must accomplish the work and the amount of work involved.

In the GEIS (NRC 1996), NRC analyzed seven case study sites (including TMI-1) with respect to typical refurbishment scenarios. NRC selected a variety of nuclear plant sites that would represent the range of plant types in the United States. Then, NRC based its analyses on bounding work force estimates derived from these typical refurbishment scenarios at the case study sites. In the GEIS, NRC estimates that the most additional personnel needed to perform refurbishment activities at a pressurized water reactor would typically be 2,273 persons during a 9-month major refurbishment outage immediately before the expiration of the initial operating license. NRC also estimates that, after the refurbishment workforce has reached its peak, refueling would be undertaken to prepare for continued operation of the plant. In an effort to account for uncertainty surrounding workforce numbers, NRC performed a sensitivity analysis where socioeconomic impacts were predicted in response to a work force roughly 50 percent larger than the projected bounding case for a pressurized water reactor work force, or 3,400 workers. Having established this upper value for what would be a single event in the remainder of the life of the plant, the GEIS uses this number as the expected number of additional permanent workers needed per unit attributable to refurbishment.

AmerGen has identified one refurbishment project for TMI-1. This project qualifies for inclusion in this environmental report and will be analyzed in Chapter 4. AmerGen has determined that the GEIS work force size and scheduling assumptions amply bound the TMI-1 refurbishment work force size and scheduling. AmerGen estimates that refurbishment activities would last no longer than 70 days. Construction activities for the long-term storage facility for the original steam generators will require approximately 50 workers and will occur first. Steam generator replacement will follow and will require approximately 900 workers.

In Chapter 4, for analyses based on employment numbers, the steam generator replacement employment numbers are expected to bound the employment-related impacts of all steam generator replacement activities. Therefore, a peak refurbishment work force of 900 workers will be assumed for analyzing refurbishment impacts. For analyses based on other criteria, such as land-disturbance, the steam generator replacement activities and the long-term storage facility construction will be analyzed separately.

License Renewal Increment

Performing the license renewal activities described in Section 3.3 would necessitate increasing the TMI-1 staff workload by some increment. The size of this increment would be a function of the schedule within which AmerGen must accomplish the work and the amount of work involved. The analysis of license renewal employment increment focuses on programs and activities for managing the effects of aging.

The GEIS (NRC 1996) assumes that NRC would renew a nuclear power plant license for a 20-year period beyond the term of its initial license, and that NRC would issue the renewal approximately 10 years before the initial license expires. In other words, the renewed license would be in effect for approximately 30 years. The GEIS further assumes that the utility would initiate surveillance, monitoring, inspections, testing, trending, and recordkeeping (SMITTR) activities at the time of issuance of the new license and would conduct license renewal SMITTR activities throughout the remaining 30-year life of the plant, sometimes during full-power operation (NRC 1996), but mostly during normal refueling and the 5- and 10-year in-service inspection and refueling outages (NRC 1996).

AmerGen has determined that the GEIS scheduling assumptions are reasonably representative of TMI-1 incremental, license renewal, workload scheduling. Many TMI-1 license renewal SMITTR activities would have to be performed during outages. Although some TMI-1 license renewal SMITTR activities would be one-time efforts, others would be recurring periodic activities that would continue for the life of the plant.

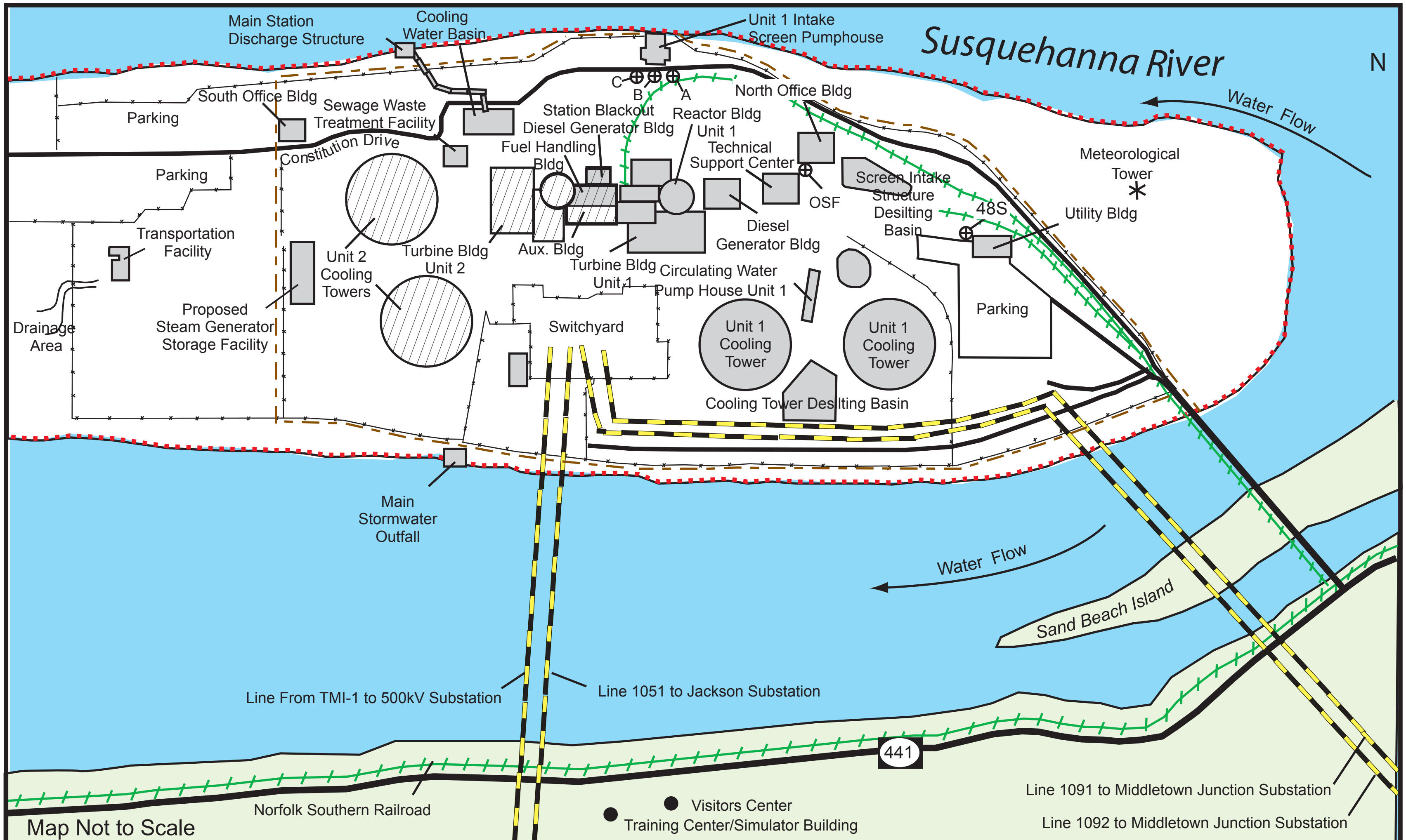
The GEIS estimates that the most additional personnel needed to perform license renewal SMITTR activities would typically be 60 persons during the 3-month duration of a 10-year in-service inspection and refueling outage. Having established this upper value for what would be a single event in 20 years, the GEIS uses this number as the expected number of additional permanent workers needed per unit attributable to license renewal. GEIS Section C.3.1.2 uses this approach in order to "...provide a realistic upper bound to potential population-driven impacts…."

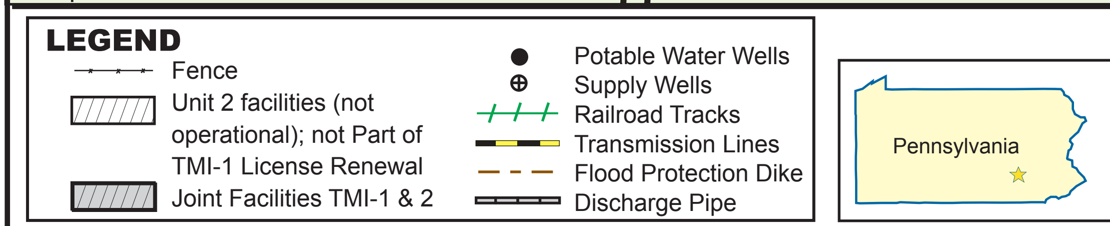
AmerGen expects that its existing capability for temporarily supplementing the workforce for routine activities, such as outages, will most likely enable AmerGen to perform the increased SMITTR workload without adding workers to the TMI-1 staff. However, for purposes of analysis in this environmental report, AmerGen conservatively assumes that TMI-1 would require 60 additional permanent workers to perform all license renewal SMITTR activities and that all 60 employees would migrate into the 50-mile radius. Adding 60 full-time employees to the plant work force for the period of extended operation would have the indirect effect of creating additional jobs. Considering the size of the 50-mile radius population (2,546,479) and the fact that most indirect jobs would be service-related, AmerGen assumes that the majority of indirect workers would already be residing within the 50-mile radius.

Table 3.1-1 List of Radioactive Waste Systems at TMI-1

Radioactive Waste Systems
Spent fuel and control rod handling and packaging
Incore detector removal and packaging
Out-of-core detector removal and packaging
Purification filter removal and packaging
Liquid waste disposal system
Waste gas system
Solid waste disposal and packaging

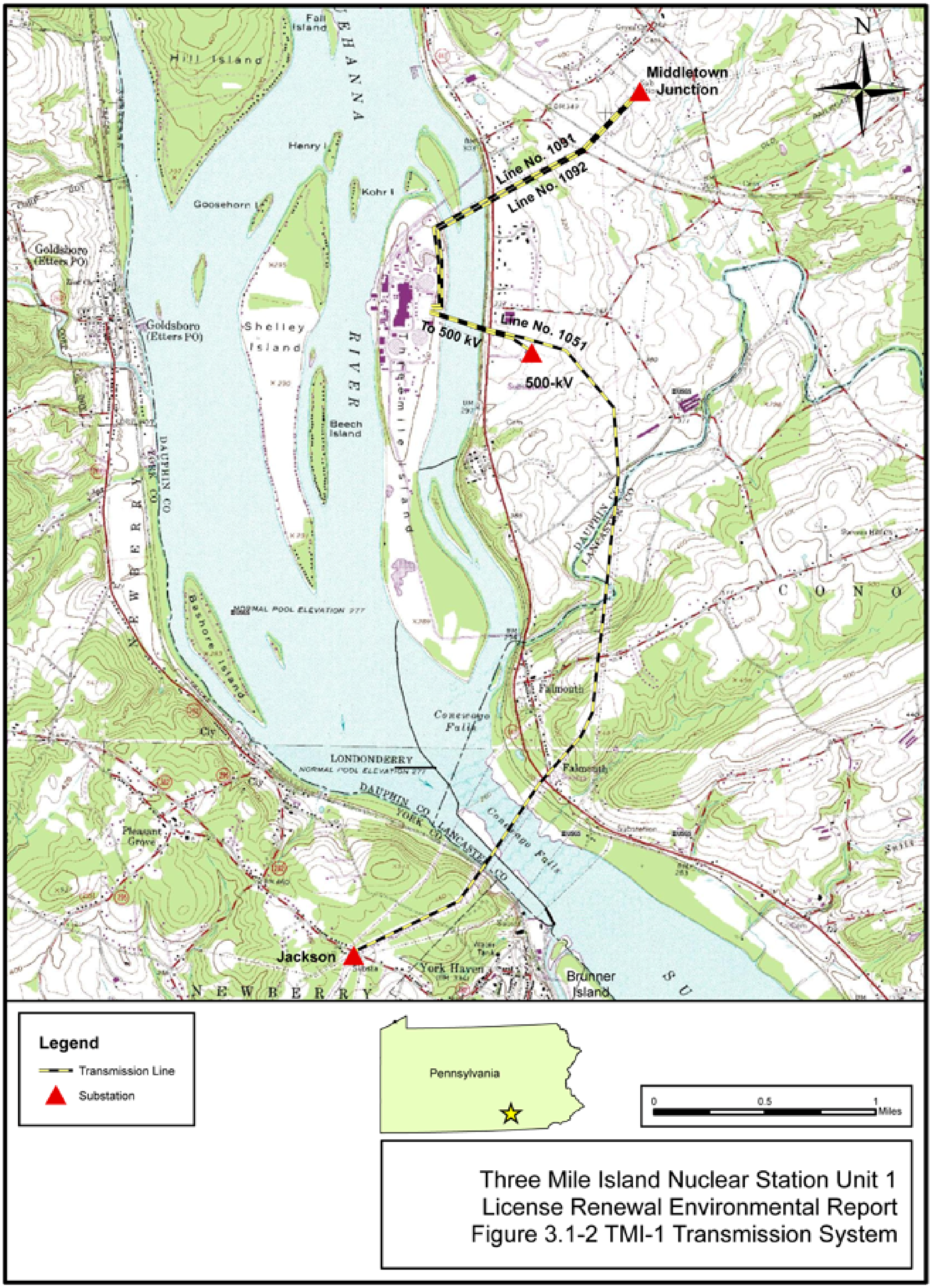
Source: AmerGen 2006a





Three Mile Island Nuclear Station Unit 1
License Renewal Environmental Report
Figure 3.1-1 General Plant Layout

Figure 3.1-2 TMI Transmission System



3.5 REFERENCES

Note to reader: Some web pages cited in this document are no longer available, or are no longer available through the original URL addresses. Hard copies of cited web pages are available in AmerGen files. Some sites, for example the census data, cannot be accessed through their given URLs. The only way to access these pages is to follow queries on previous web pages. The complete URLs used by AmerGen have been given for these pages, even though they may not be directly accessible. Also, all references are specific to respective chapter.

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Chapter 4

Environmental Consequences of the Proposed Action and Mitigating Actions

NRC

The report must contain a consideration of alternatives for reducing impacts…for all Category 2 license renewal issues….” 10 CFR 51.53(c)(3)(iii)

“The environmental report shall include an analysis that considers…the environmental effects of the proposed action…and alternatives available for reducing or avoiding adverse environmental effects.” 10 CFR 51.45(c) as adopted by 10 CFR 51.53(c)(2)

The environmental report shall discuss the “…impact of the proposed action on the environment. Impacts shall be discussed in proportion to their significance….” 10 CFR 51.45(b)(1) as adopted by 10 CFR 51.53(c)(2)

“The information submitted…should not be confined to information supporting the proposed action but should also include adverse information.” 10 CFR 51.45(e) as adopted by 10 CFR 51.53(c)(2)

Chapter 4 presents an assessment of the environmental consequences associated with the renewal of the Three Mile Island Nuclear Station Unit 1 (TMI-1) operating license. The U.S. Nuclear Regulatory Commission (NRC) has identified and analyzed 92 environmental issues that it considers to be associated with nuclear power plant license renewal and has designated the issues as Category 1, Category 2, or NA (not applicable). NRC designated an issue as Category 1 if, based on the result of its analysis, the following criteria were met:

- the environmental impacts associated with the issue have been determined to apply either to all plants or, for some issues, to plants having a specific type of cooling system or other specified plant or site characteristic;
- a single significance level (i.e., small, moderate, or large) has been assigned to the impacts that would occur at any plant, regardless of which plant is being evaluated (except for collective offsite radiological impacts from the fuel cycle and from high-level waste and spent-fuel disposal); and
- mitigation of adverse impacts associated with the issue has been considered in the analysis, and it has been determined that additional plant-specific mitigation measures are likely to be not sufficiently beneficial to warrant implementation.

If the NRC analysis concluded that one or more of the Category 1 criteria could not be met, NRC designated the issue as Category 2. NRC requires plant-specific analyses for Category 2 issues.

Finally, NRC designated two issues as NA, signifying that the categorization and impact definitions do not apply to these issues.

NRC rules do not require analyses of Category 1 issues that NRC resolved using generic findings (10 Code of Federal Regulations (CFR) 51) as described in the Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) (NRC 1996). An applicant may reference the generic findings or GEIS analyses for Category 1 issues. Of the 92 total issues, NRC designated 69 as Category 1 and 21 as Category 2.

Appendix A of this report lists the 92 issues and identifies the environmental report section that addresses each issue.

CATEGORY 1 AND NA LICENSE RENEWAL ISSUES

NRC

"The environmental report for the operating license renewal stage is not required to contain analyses of the environmental impacts of the license renewal issues identified as Category 1 issues in Appendix B to subpart A of this part." 10 CFR 51.53(c)(3)(i)

"…[A]bsent new and significant information, the analyses for certain impacts codified by this rulemaking need only be incorporated by reference in an applicant's environmental report for license renewal…." (NRC 1996b, pg. 28483)

Category 1 License Renewal Issues

AmerGen Energy Company, LLC (AmerGen) has determined that 10 of the 69 Category 1 issues do not apply to TMI-1 because they are specific to design or operational features that are not found at the facility. Appendix Table A-1 lists the 69 Category 1 issues, indicates whether or not each issue is applicable to TMI-1, and if inapplicable provides AmerGen's basis for this determination. Appendix Table A-1 also includes references to supporting analyses in the GEIS where appropriate.

AmerGen has reviewed the NRC findings at Table B-1 in Appendix B to 10 CFR 51 and has not identified any new and significant information that would make the NRC findings, with respect to Category 1 issues, inapplicable to TMI-1. Therefore, AmerGen adopts by reference the NRC findings for these Category 1 issues. AmerGen will undertake refurbishment activities associated with license renewal and has included evaluation of the impacts, as indicated in the GEIS. AmerGen has determined that no refurbishment activities would change the conclusions identified in the GEIS and therefore, AmerGen adopts by reference the NRC conclusions regarding those Category 1 issues relative to refurbishment.

"NA" License Renewal Issues

NRC determined that its categorization and impact-finding definitions did not apply to Issues 60 and 92; however, AmerGen included these issues in Table A-1. NRC noted that applicants currently do not need to submit information on Issue 60, chronic effects from electromagnetic fields (10 CFR 51). For Issue 92, environmental justice, NRC does not require information from applicants, but noted that it will be addressed in individual license renewal reviews (10 CFR 51). AmerGen has included environmental justice demographic information in Section 2.6.2.

CATEGORY 2 LICENSE RENEWAL ISSUES

NRC

"The environmental report must contain analyses of the environmental impacts of the proposed action, including the impacts of refurbishment activities, if any, associated with license renewal and the impacts of operation during the renewal term, for those issues identified as Category 2 issues in Appendix B to subpart A of this part." 10 CFR 51.53(c)(3)(ii)

"The report must contain a consideration of alternatives for reducing adverse impacts, as required by § 51.45(c), for all Category 2 license renewal issues…." 10 CFR 51.53(c)(3)(iii)

NRC designated 21 issues as Category 2. Sections 4.1 through 4.20 (Section 4.17 addresses 2 issues) address the Category 2 issues, beginning with a statement of the issue. Five Category 2 issues apply to operational features that TMI-1 does not have. If the issue does not apply to TMI-1, the section explains the basis for inapplicability.

For the 16 Category 2 issues that AmerGen has determined to be applicable to TMI-1, the appropriate sections contain the required analyses. These analyses include conclusions regarding the significance of the impacts relative to the renewal of the operating license and refurbishment activities for TMI-1 and, if applicable, discuss potential mitigative alternatives to the extent required. AmerGen has identified the significance of the impacts associated with each issue as either small, moderate, or large, consistent with the criteria that NRC established in 10 CFR 51, Appendix B, Table B-1, Footnote 3 as follows:

> SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts, the Commission has concluded that those impacts that do not exceed permissible levels in the Commission's regulations are considered small.
>
> MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource.
>
> LARGE - Environmental effects are clearly noticeable and are sufficient to destabilize important attributes of the resource.

In accordance with National Environmental Policy Act practice, AmerGen considered ongoing and potential additional mitigation in proportion to the significance of the impact to be addressed (i.e., impacts that are small receive less mitigative consideration than impacts that are large).

4.1 WATER USE CONFLICTS

NRC

"If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is less than 3.15×10^{12} ft^3 / year (9×10^{10} m^3/year), an assessment of the impact of the proposed action on the flow of the river and related impacts on instream and riparian ecological communities must be provided. The applicant shall also provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow." 10 CFR 51.53(c)(3)(ii)(A)

"…The issue has been a concern at nuclear power plants with cooling ponds and at plants with cooling towers. Impacts on instream and riparian communities near these plants could be of moderate significance in some situations…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 13

The NRC made surface water use conflicts a Category 2 issue because consultations with regulatory agencies indicate that water use conflicts are already a concern at two closed-cycle plants and may be a problem in the future at other plants. In the GEIS, NRC notes two factors that may cause water use and availability issues to become important for some nuclear power plants that use cooling towers. First, some plants equipped with cooling towers are located on small rivers that are susceptible to droughts or competing water uses. Second, consumptive water loss associated with closed-cycle cooling systems may represent a substantial proportion of the flows in small rivers (NRC 1996, Section 4.3.2.1).

As discussed in Section 3.1, TMI-1 has a cooling tower-based heat dissipation system. Cooling water lost to cooling tower evaporation is replaced by make-up water pumped from the Susquehanna River at a permitted consumptive average rate of 18 million gallons per day (gpd) (SRBC 1995). Based on data from water years 1891 to 2004, the annual mean flow of the Susquehanna River at Harrisburg, approximately 11 miles upstream of TMI-1, is 34,450 cubic feet per second [(cfs) (1.09×10^{12} cubic feet per year)] (Durlin and Schaffstall 2005), which means that the Susquehanna River meets the NRC definition of a small river. Therefore, this issue applies to TMI-1.

The lowest annual mean flow at the Harrisburg gauging Station is 16,940 cfs (1.098×10^{10} gpd). The lowest daily mean at the station is 1,700 cfs (1.10×10^{9} gpd). (Durlin and Schaffstall 2005) River flow at Three Mile Island is directly controlled by the York Haven Dam (York Haven Hydroelectric Station) which is immediately downstream of the plant, across the main channel of the river. A smaller dam (Red Hill) is located across the east channel of the river adjacent to the site. Together these dams form Lake Frederick (York Haven Pond). The York Haven Hydroelectric Station is operated on a run-of-river basis and its power output is dependent upon river flow. The reservoir is used for limited peaking operation during periods of low river flow (AmerGen 2006). At TMI-1, the circulating water system can withdraw water from the Susquehanna River for consumptive use up to 18 million gpd (SRBC 1995). The average estimated withdrawal of surface water at the Unit 1 intake structure is 24,000 gallons per minute (gpm) (AmerGen 2007a). TMI-1 withdrawals from the Susquehanna River represent less than 1.6 percent of the river flow during typical drought periods (lowest daily mean), less than 0.2 percent of the lowest annual mean flow, and less than 0.1 percent of average annual flow. TMI-1 also participates in the Cowanesque Lake water storage project. TMI-1 has sponsored a total of 8,274 acre-feet of compliance storage at the Cowanesque project, of which 4,250 acre-feet of water could be released to help mitigate any impact to the Susquehanna River caused by plant operations during a drought of record (SRBC 1995). The Susquehanna River Basin Commission (SRBC) monitors water flows of the Susquehanna River. When the SRBC determines that flows in the river have reached a critical level, the SRBC directs the Army Corps of Engineers to release quantities of water identified in a separate, predetermined plan (SRBC 2005). Based on the low percentages of water use as compared to stream flow discussed above and the potential of releasing water into the system during periods of drought, AmerGen has determined that any impacts to instream and riparian communities and to alluvial water bearing material (aquifers) caused by TMI-1 make-up water withdrawal from the Susquehanna River would be SMALL and would not warrant additional mitigation.

4.2 ENTRAINMENT OF FISH AND SHELLFISH IN EARLY LIFE STAGES

NRC

"If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations…or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from…entrainment." 10 CFR 51.53(c)(3)(ii)(B)

"...The impacts of entrainment are small in early life stages at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems. Further, ongoing efforts in the vicinity of these plants to restore fish populations may increase the numbers of fish susceptible to intake effects during the license renewal period, such that entrainment studies conducted in support of the original license may no longer be valid..." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 25

The issue of entrainment of fish and shellfish in early life stages does not apply to TMI-1 because condenser cooling at the unit does not utilize a once-through cooling water system or a cooling pond heat dissipation system.

4.3 IMPINGEMENT OF FISH AND SHELLFISH

NRC

"If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations…or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from…impingement…." 10 CFR 51.53(c)(3)(ii)(B)

"…The impacts of impingement are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems…." 10 CFR 51, Subpart A, Appendix B, Table B 1, Issue 26

The issue of impingement of fish and shellfish does not apply to TMI-1 because condenser cooling at the unit does not utilize a once-through cooling water system or a cooling pond heat dissipation system.

4.4 HEAT SHOCK

NRC

"If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act… 316(a) variance in accordance with 40 CFR Part 125, or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock …." 10 CFR 51.53(c)(3)(ii)(B)

"…Because of continuing concerns about heat shock and the possible need to modify thermal discharges in response to changing environmental conditions, the impacts may be of moderate or large significance at some plants…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 27

The issue of heat shock does not apply to TMI-1 because condenser cooling at the unit does not utilize a once-through cooling water system or a cooling pond heat dissipation system.

4.5 GROUNDWATER USE CONFLICTS (PLANTS USING >100 GPM OF GROUNDWATER)

NRC

"If the applicant's plant…pumps more than 100 gallons (total onsite) of groundwater per minute, an assessment of the impact of the proposed action on groundwater use must be provided." 10 CFR 51.53(c)(3)(ii)(C)

"Plants that use more than 100 gpm may cause groundwater use conflicts with nearby groundwater users." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 33

NRC made groundwater use conflicts a Category 2 issue because, at a withdrawal rate of more than 100 gpm, a cone of depression could extend offsite. This could deplete the groundwater supply available to offsite users, an impact that could warrant mitigation. Information to be ascertained includes: (1) TMI-1 groundwater withdrawal rate (whether greater than 100 gpm), (2) drawdown at offsite location, and (3) impact on neighboring wells.

Based on information presented in Section 2.3, TMI-1 used an average of between 95 to 115 gpm of groundwater from the seven facility wells for the period of 2003 through 2005. Therefore, the issue of groundwater use conflicts does apply.

In 1998, TMI-1 applied to the SRBC to increase its groundwater withdrawal from Wells A, B, and C, to 225,000 gpd. As part of the original SRBC groundwater use approval process simultaneous pump tests were performed in 1996. The pumping rate for the test was 75 percent of the requested 225,000 gpd or 168,750 gpd (117 gpm). No impacts to the operation of the on-site OSF well or the 48S well were observed and the SRBC determined that no other wells on Three Mile Island or along the eastern shore of the river had been affected by the site production well operations (Wells A, B, and C) (SRBC 1999). Subsequently in 1999, the SRBC approved the new 30-day average flow of 225,000 gpd for Wells A, B, and C. As discussed in Section 2.3, recharge to the site's groundwater pumping area is primarily along subcrops of the bedrock aquifer in the Susquehanna River and not along bedding planes or joints supplying water to off-site users.

Based on the results of the pump test performed in 1996 on Wells A, B, and C production, which indicated no effect on nearby wells, AmerGen concludes there will be SMALL to no impacts to nearby groundwater users during the period of relicensing operations.

4.6 GROUNDWATER USE CONFLICTS (PLANTS USING COOLING TOWERS WITHDRAWING MAKEUP WATER FROM A SMALL RIVER)

NRC

"If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is less than 3.15×10^{12} ft^3 / year...[t]he applicant shall also provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow." 10 CFR 51.53(3)(ii)(A)

"…Water use conflicts may result from surface water withdrawals from small water bodies during low flow conditions which may affect aquifer recharge, especially if other groundwater or upstream surface water users come on line before the time of license renewal…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 34

NRC made this groundwater use conflict a Category 2 issue because surface water withdrawals from small rivers could adversely impact aquatic life, downstream users of a small river, and groundwater-aquifer recharge. This is a particular concern during low-flow conditions and could create a cumulative impact due to upstream consumptive use. Cooling towers and cooling ponds lose flow by evaporation, which is necessary to cool the heated water before it is discharged to the environment.

The issue of potential groundwater use conflicts applies because TMI-1 withdraws makeup water from a small river, the Susquehanna River, which as discussed in Section 4.1, has an annual flow of 34,450 cubic feet per second ($1.09\text{x}10^{12}$ cubic feet per year) at the Harrisburg gauging station located approximately 11 miles upstream of TMI-1. As discussed in Section 3.1, TMI-1 has a natural-draft cooling tower heat dissipation system. Circulated cooling water lost to cooling tower evaporation is replaced by make-up water pumped from the Susquehanna River. TMI-1 is located on Lake Frederick, created by the damming of the Susquehanna River by the Red Hill Dam and the York Haven Dam (York Haven Hydroelectric Station) which is immediately downstream of TMI-1 across the main channel of the river.

As discussed in Section 4.1, TMI-1 withdraws surface water at a rate approximately 1.6 percent of the lowest daily mean, less than 0.2 percent of the lowest annual mean flow, and less than 0.1 percent of average annual flow of the Susquehanna River. As discussed in Section 4.1, TMI-1 participates in the Cowanesque Lake water storage project which allows TMI-1 a sponsored total of 8,274 acre-feet of compliance storage at the Cowanesque project. SRBC can direct the Army Corps of Engineers to release water during periods of drought. Of the 8,274 acre-feet sponsored by TMI-1, approximately 4,250 acre-feet of water would mitigate any impact to the Susquehanna River caused by plant operations during a drought of record, thus allowing continued operations. AmerGen concludes that impacts of withdrawing water from the river on the alluvial water bearing unit (aquifer) would be SMALL and that additional mitigation measures would not be warranted.

4.7 GROUNDWATER USE CONFLICTS (PLANTS USING RANNEY WELLS)

NRC

"If the applicant's plant uses Ranney wells…an assessment of the impact of the proposed action on groundwater use must be provided." 10 CFR 51.53(c)(3)(ii)(C)

"…Ranney wells can result in potential ground-water depression beyond the site boundary. Impacts of large ground-water withdrawal for cooling tower makeup at nuclear power plants using Ranney wells must be evaluated at the time of application for license renewal…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 35

NRC made this groundwater use conflict a Category 2 issue because large quantities of groundwater withdrawn from Ranney wells could degrade groundwater quality at river sites by induced infiltration of poor-quality river water into an aquifer.

The issue of groundwater use conflicts does not apply to TMI-1 because the plant does not use Ranney wells. As Section 3.1 describes, TMI-1 uses a closed cycle cooling system with cooling towers that removes make-up water from the Susquehanna River and discharges blowdown to the Susquehanna River.

4.8 DEGRADATION OF GROUNDWATER QUALITY

NRC

"If the applicant's plant is located at an inland site and utilizes cooling ponds, an assessment of the impact of the proposed action on groundwater quality must be provided." 10 CFR 51.53(c)(3)(ii)(D)

"…Sites with closed-cycle cooling ponds may degrade ground-water quality. For plants located inland, the quality of the ground water in the vicinity of the ponds must be shown to be adequate to allow continuation of current uses…." 10 CFR 51, Subpart A, Appendix B, Table B 1, Issue 39

NRC made degradation of groundwater quality a Category 2 issue because evaporation from closed-cycle cooling ponds concentrates dissolved solids in the water and settles suspended solids. In turn, seepage into the water table aquifer could degrade groundwater quality.

The issue of groundwater degradation does not apply to TMI-1 because the plant does not use cooling ponds. As Section 3.1 describes, TMI-1 uses a closed cycle cooling system with natural draft cooling towers that withdraws make-up water from and discharges blowdown to the Susquehanna River.

4.9 IMPACTS OF REFURBISHMENT ON TERRESTRIAL RESOURCES

NRC

The environmental report must contain an assessment of "…the impact of refurbishment and other license-renewal-related construction activities on important plant and animal habitats…." 10 CFR 51.53(c)(3)(ii)(E)

"…Refurbishment impacts are insignificant if no loss of important plant and animal habitat occurs. However, it cannot be known whether important plant and animal communities may be affected until the specific proposal is presented with the license renewal application…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 40

"…If no important resource would be affected, the impacts would be considered minor and of small significance. If important resources could be affected by refurbishment activities, the impacts would be potentially significant…." (NRC 1996a, Section 3.6, pg. 3-6)

NRC made impacts to terrestrial resources from refurbishment a Category 2 issue, because the significance of ecological impacts cannot be determined without considering site- and project-specific details (NRC 1996). Aspects of the site and project to be ascertained are: (1) the identification of important ecological resources, (2) the nature of refurbishment activities, and (3) the extent of impacts to plant and animal habitats.

Activities associated with refurbishment at TMI-1 are described in Section 3.2. Most of the refurbishment activities would be performed on equipment inside existing buildings. However, laydown areas, a permanent steam generator storage facility, and several temporary facilities would be needed to support the refurbishment activities. All new permanent facilities and temporary structures would be located in previously disturbed areas. AmerGen anticipates that the amount of land utilized would be less than 10 acres.

As discussed in Section 2.4, the portion of Three Mile Island that is occupied by the station is a developed industrial area that is devoid of important plant and animal habitats. The southern portion of the island is largely undeveloped and contains wetlands that provide nesting and foraging habitat for migratory waterfowl. The southern portion of the island also contains fallow field areas that are surrounded by a woodland buffer. Riparian buffer areas around the perimeter of the island are intact. Forested riparian areas are isolated to the southern part of the Island. Animal species that inhabit these natural areas could be temporarily displaced by noise and vibration from machinery and personnel associated with refurbishment activities, but such disturbances would be temporary and minor.

As stated in Section 3.2, the replacement steam generators will be manufactured in France and transported to TMI-1. The exact mode and route of transportation once the steam generator arrives in a U. S. port (e.g., Baltimore, Newark, Philadelphia) is undecided at this time. Potential impacts to the terrestrial resources from either a rail or road option would meet the necessary federal, state, and local regulatory requirements prior to transport. Some of these activities could involve dredging or fill activities or temporary removal of interferences along routes, which could have temporary impacts on terrestrial resources.

Table 2.5-1 identifies a number of threatened or endangered species that have been recorded in counties within which TMI-1 and its associated transmission lines are located. As stated in Section 2.5, the only listed species that have been known to occur at TMI-1 are American holly (state-listed as threatened), bald eagle (state-listed as threatened), peregrine falcon (state-listed as endangered), and osprey (state-listed as threatened). The American holly is not known to be present in the industrial or paved areas of the site. Peregrine falcons have nested on the Unit 1 Reactor Building every year since 2002. Ospreys have nested on the meteorological tower every year since 2004. Bald eagles have become relatively common along the Susquehanna River and are occasionally observed at Three Mile Island. However, no bald eagle nests are known to occur on the island. Refurbishment activities could startle peregrine falcons and ospreys or other birds at TMI-1, but these birds have presumably become habituated to industrial activities at the site, including movement of personnel and machinery and loud noise. The steam generator replacement is planned for fall of 2009 to coincide with a planned outage, and these activities would create significant disturbances at and around the Unit 1 containment dome; however, the peregrine falcon nestlings have historically fledged the nest by late summer and the adult birds have migrated to their wintering ranges (PDEP 2007). In addition, the peregrine falcon nest is not near the ground but is instead high atop the containment, which serves to mitigate potential disturbances that might occur if the nest were lower and birds were late vacating the nest. As further evidenced from AmerGen's consultations with the Pennsylvania Game Commission, the conclusion that "adverse impacts to any special concern species of birds or mammals is not expected". Copies of correspondences with all state and federal agencies concerning terrestrial resources are presented in Appendix C. In summary, AmerGen concludes that impacts to important terrestrial resources from refurbishment activities would be SMALL and do not warrant mitigation.

4.10 THREATENED OR ENDANGERED SPECIES

NRC

"Additionally, the applicant shall assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act." 10 CFR 51.53(c)(3)(ii)(E)

"Generally, plant refurbishment and continued operation are not expected to adversely affect threatened or endangered species. However, consultation with appropriate agencies would be needed at the time of license renewal to determine whether threatened or endangered species are present and whether they would be adversely affected." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 49

NRC made impacts to threatened and endangered species a Category 2 issue because the status of many species is being reviewed, and site-specific assessment is required to determine whether any identified species could be affected by refurbishment activities or continued plant operations through the renewal period. In addition, compliance with the Endangered Species Act requires consultation with the appropriate federal agency (NRC 1996a, Sections 3.9 and 4.1).

Section 2.2 of this Environmental Report describes the aquatic communities of the Susquehanna River. Section 2.4 describes important terrestrial habitats at TMI-1 and along the associated transmission corridors. Section 2.5 discusses threatened or endangered species that may occur in the vicinity of TMI-1 or its associated transmission corridors.

Except as discussed in Section 2.5, AmerGen is not aware of any threatened or endangered species that could occur at TMI-1 or along the associated transmission corridors. Current operation of TMI-1 and vegetation management practices along the transmission line rights-of-way do not adversely affect any listed species or its habitat (see Section 2.5). Furthermore, plant operations and transmission line maintenance practices are not expected to change significantly during the license renewal term. Therefore, no adverse impacts to threatened or endangered terrestrial species from current or future operations are anticipated.

AmerGen contacted the Pennsylvania Department of Conservation and Natural Resources, the Pennsylvania Game Commission, the Pennsylvania Fish and Boat Commission, and the U.S. Fish and Wildlife Service requesting information on any listed species or critical habitats that might occur on the TMI-1 site or along the associated transmission corridors, with particular emphasis on species that might be adversely affected by continued operation over the license renewal period. Agency responses are provided in Appendix C. All four agencies indicated that license renewal is unlikely to affect any listed species.

As discussed in Section 3.2, AmerGen plans refurbishment in the form of steam generator replacement, including construction of a long term storage facility for the original steam generators. No refurbishment-related impacts to special status species are expected to occur. The steam generator replacement is planned for the fall of 2009, and adult peregrine falcons and their chicks have historically vacated the nest on the Reactor Building of Unit 1 by August (PDEP 2007).

As stated in Section 4.9, the exact route over which the replacement steam generators will be transported from the port of call to TMI-1 has not been established. The route will depend on the mode of transportation to be used (e.g., barge, rail, road). Options being considered are discussed in Section 3.2. It is possible that endangered or threatened species or their habitats would be present along the route, regardless of which option is chosen. Even so, unless dredge or fill activities are necessary to implement an option, effects caused by steam generator transport on threatened or endangered species in the vicinity of the route are not expected to differ from or add measurably to the existing effects of other vehicles and materials already transported along the routes. In any event, AmerGen will comply with applicable federal, state, and local regulatory requirements for the selected option.

If an option were to involve dredge or fill activities, the potential for impacts on threatened and endangered species would be reviewed (and mitigation measures identified) in the context of seeking regulatory consents for the dredge or fill activity. Potentially applicable requirements are listed in Table 9.1-3.

Because AmerGen has no plan to alter operations after license renewal, has committed to comply with applicable regulatory requirements related to refurbishment activities, and resource agencies evidenced no serious concerns about license renewal impacts, AmerGen concludes that impacts to threatened or endangered species from license renewal would be SMALL and do not warrant mitigation. License renewal of TMI-1 is not expected to result in taking of any threatened or endangered species. Renewal of the TMI-1 license also is not likely to jeopardize the continued existence for any threatened or endangered species or result in the destruction or adverse modifications of any critical habitat.

4.11 AIR QUALITY DURING REFURBISHMENT (NON-ATTAINMENT OR MAINTENANCE AREAS)

NRC

"If the applicant's plant is located in or near a nonattainment or maintenance area, an assessment of vehicle exhaust emissions anticipated at the time of peak refurbishment workforce must be provided in accordance with the Clean Air Act as amended." 10 CFR 51.53(c)(3)(ii)(F)

"…Air quality impacts from plant refurbishment associated with license renewal are expected to be small. However, vehicle exhaust emissions could be cause for concern at locations in or near nonattainment or maintenance areas. The significance of the potential impact cannot be determined without considering the compliance status of each site and the numbers of workers expected to be employed during the outage…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 50

NRC made impacts to air quality during refurbishment a Category 2 issue because vehicle exhaust emissions could be cause for some concern, and a general conclusion about the significance of the potential impact could not be drawn without considering the compliance status of each site and the number of workers expected to be employed during an outage (NRC 1996).

Activities associated with refurbishment at TMI-1 are discussed in Section 3.2. Most of the refurbishment activities would be performed on equipment inside existing buildings and would not generate atmospheric emissions. However, laydown areas, a permanent steam generator storage facility, and several temporary facilities would be needed to support the refurbishment activities. AmerGen estimates indicate that the disturbed area for construction and laydown areas would be less than 10 acres. The small amount of disturbed area and implementation of best management practices (e.g., watering, silt fences, covering soil piles, etc.) would minimize the amount of fugitive dust generated during construction. Also, particulate matter in the form of fugitive dust consists primarily of large particles that settle quickly and thus have minimal adverse public health effects.

During refurbishment, temporary and localized increases in atmospheric concentrations of nitrogen oxides (NOx), carbon monoxide, sulfur dioxide (SO2), volatile organic compounds (VOC), ammonia and particulate matter (PM) would result from exhaust emissions of workers' vehicles, heavy construction vehicles, diesel generators, and other machinery and tools. As discussed in Section 3.3 of the GEIS (NRC 1996a), air quality impacts from these sources would be minor and of short duration. The amount of pollutants emitted from construction vehicles and equipment and construction worker commute traffic would be small compared to total vehicular emissions in the region.

As discussed in Section 2.10, the U.S. Environmental Protection Agency (EPA) has established National Ambient Air Quality Standards (NAAQS) for six common pollutants and has designated all areas of the United States as having air quality either better than (attainment) or worse than (non-attainment) the NAAQS. TMI-1 is located in the Harrisburg-Lebanon-Carlisle, Pennsylvania metropolitan statistical area (MSA), which is designated as a subpart 1 non-attainment area under the 8-hour ozone NAAQS and a non-attainment area under the $PM_{2.5}$ (fine particulate matter with an aerodynamic diameter of 2.5 microns or less) NAAQS. The MSA is designated as an attainment area for all other NAAQS.

As noted in Section 3.3 of the GEIS (NRC 1996a), a conformity analysis is required for each pollutant where the total of direct and indirect emissions caused by a proposed federal action would exceed established threshold emission levels in a non-attainment or maintenance area. Federal conformity rules are defined in 40 CFR Parts 51 and 93. Due to Dauphin County's ozone non-attainment status, the generation of NOx and VOC, which combine in the presence of heat and sunlight to create ozone, are a source of concern. Fine particulates ($PM_{2.5}$) can result from both direct and indirect sources. Gasoline and diesel fueled vehicles emit both direct $PM_{2.5}$ and gases (NOx, SO2, VOC, ammonia) that react in the air to form $PM_{2.5}$. The EPA requires NOx and SO2 emissions to be considered in $PM_{2.5}$ conformity assessments, but consideration of VOC and ammonia emissions is only required if the EPA or the state air agency determine that one or more of these precursors are significant (71 Federal Register (FR) 40420). No such determination has been made for Dauphin County. Consequently, direct generation of $PM_{2.5}$ and the generation of SO2 and NOx emissions are sources of concern due to the county's status as a $PM_{2.5}$ non-attainment area.

For ozone, the threshold emissions levels are 100 tons per year (tpy) for NOx and 50 tpy for VOC. For $PM_{2.5}$, the threshold emissions levels are 100 tpy for direct $PM_{2.5}$ emissions and 100 tpy for each of the $PM_{2.5}$ precursors, NOx and SO2 (71 FR 40420).

As discussed in Section 3.2, the refurbishment activities would begin with the commencement of construction activities for the steam generator storage facility. The peak period of activity would occur when the actual removal and replacement of the steam generators take place during a 70-day outage between fall 2009 and the date on which the TMI-1 license expires. Assuming carpooling by some workers and that all passenger vehicles and all construction equipment will not be in simultaneous use, the following vehicle numbers have been analyzed. During site preparation, an average of about 60 vehicles per day ranging from passenger vehicles to earthmovers would be used for construction activities, with a peak of approximately 100 vehicles. During the 70-day steam generator replacement outage, an average of 800 vehicles ranging from passenger vehicles to earthmovers would be used for construction activities, with a peak of approximately 850 vehicles. Construction vehicles and machinery would be equipped with standard pollution-control devices to minimize emissions. These emissions would be small compared to regulatory thresholds and a conformity determination for this project pursuant to the Clean Air Act would not be required.

4.12 MICROBIOLOGICAL ORGANISMS

NRC

"If the applicant's plant uses a cooling pond, lake, or canal or discharges into a river having an annual average flowrate of less than 3.15×10^{12} ft^3/year (9×10^{10} m^3/year), an assessment of the impact of the proposed action on public health from thermophilic organisms in the affected water must be provided." 10 CFR 51.53(c)(3)(ii)(G)

"These organisms are not expected to be a problem at most operating plants except possibly at plants using cooling ponds, lakes, or canals that discharge to small rivers. Without site-specific data, it is not possible to predict the effects generically." 10 CFR 51,Subpart A, Appendix B, Table B-1, Issue 57

Due to the lack of sufficient data from facilities using cooling ponds, lakes, or canals or discharging to small rivers, NRC designated impacts on public health from thermophilic organisms a Category 2 issue. Information to be determined is: (1) whether the plant discharges to a small river, and (2) whether discharge characteristics (particularly temperature) are favorable to the survival of thermophilic organisms.

This issue is applicable to TMI-1 because the plant discharges to the Susquehanna River, which has an annual mean flow of 1.09×10^{12} cubic feet per year at the U.S. Geological Survey gauging station in Harrisburg, approximately 11 miles upstream of TMI-1 (Durlin and Schaffstall 2005). It is also relevant because the Susquehanna River in the vicinity of TMI-1 is used by the public for recreation, including boating, fishing, and swimming.

Organisms of concern include the enteric pathogens Salmonella and Shigella, the *Pseudomonas aeruginosa* bacterium, thermophilic Actinomycetes ("fungi"), the many species of Legionella bacteria, and pathogenic strains of the free-living Naegleria amoeba.

Bacteria pathogenic to humans have evolved to survive in the digestive tracts of mammals and accordingly have optimum temperatures of around 99°F (Joklik and Smith 1972). Many of these pathogenic microorganisms (e.g., *Pseudomonas*, *Salmonella*, and *Shigella*) are ubiquitous in nature, occurring in the digestive tracts of wild mammals and birds (and thus in natural waters), but are usually only a problem when the host is immunologically compromised. Thermophilic bacteria generally occur at temperatures from 77°F to 176°F, with maximum growth at 122°F to 140°F (Joklik and Smith 1972).

TMI-1 uses two natural draft cooling towers to transfer waste heat from the circulating water system which cools the main condensers to the atmosphere (see Section 3.1 for detailed description of condenser cooling system). Thermal modeling conducted for the Final Environmental Statement (FES) for operation of TMI-1 indicated that the station's discharge would have a modest rise in downstream river temperature in summer (AEC 1972). The TMI-1 National Pollutant Discharge Elimination System (NPDES) permit requires continuous temperature monitoring of the circulating cooling water system's effluent before discharge into the Susquehanna River.

Temperatures measured in the Susquehanna River during thermal plume mapping conducted in May, June, July, and August 1978, when Unit 1 was operating at 100 percent, showed that the delta T (ΔT) at the discharge ranged from 0.5˚ F below to 1.4˚ F above the ambient river temperature. In general, the heated effluent was confined to an area of approximately 16 feet offshore and 82 feet downstream of the discharge. The maximum measured discharge temperature occurred during August 1978 (77.9˚ F); when the ambient river temperature was 77˚ F (Ichthyological Associates 1979). Therefore, during this thermal plume mapping the station's discharge to the Susquehanna River exhibited temperatures indistinguishable from those measured upstream (ambient location) of the plant's intake.

Recent temperature data from an automatic temperature sensor at the station's intake screen pump house and at the discharge monitoring pit (before the water is mixed with Susquehanna River water) from August 2005 through September 2007 indicate that the 24-hr average maximum discharge temperature occurred on August 4 in 2006 (100.2° F) and on September 11 in 2007 (101.1° F) (AmerGen 2007b).

Water at these temperatures could, in theory, allow limited survival of thermophilic microorganisms, but is well below the optimal temperature range (122° F - 140° F) for growth and reproduction of thermophilic microorganisms.

Another factor controlling the survival and growth of thermophilic microorganisms in the Susquehanna River is the disinfection of TMI-1 sewage treatment plant effluent. This reduces the likelihood that a seed source or inoculant will be introduced into the Susquehanna River via the TMI-1 discharge. Wastewater, whether from domestic sewage or industrial sources, is frequently a source of pathogens in natural waters.

Fecal coliform bacteria are regarded as indicators of other pathogenic microorganisms, and are the organisms normally monitored by state health agencies. The present NPDES permit for TMI-1 requires monitoring of fecal coliforms in sewage treatment plant effluent (Outfall 101). Samples are collected once per quarter for fecal coliform analysis and other parameters. The TMI-1 NPDES permit calls for "effective disinfection" to control disease-producing organisms during the swimming season (May 1 through September 30) and imposes a limit of 200 fecal coliform colonies (geometric average value) per 100 ml sample. The NPDES permit also stipulates that no more than 10 percent of samples tested may contain 1,000 colonies/100ml sample.

Given the thermal characteristics of the Susquehanna River at the TMI-1 thermal discharge and disinfection of sewage treatment plant effluent, AmerGen does not expect station operations to stimulate growth or reproduction of thermophilic microorganisms.

AmerGen has written the Bureau of Water Supply and Wastewater Management of the Pennsylvania Department of Environmental Protection (PADEP), requesting information on any studies that may have been conducted on thermophilic microorganisms in the Susquehanna River and any concerns PADEP may have relative to these organisms. PADEP responded to AmerGen's informational request and concurred that the continued "operation of TMI-1 over the license renewal term would not stimulate growth of thermophilic pathogens." Copies of the correspondence are included in Appendix C of this environmental report. AmerGen is not aware of reported cases of illness caused by Naegleria or Legionella at, in the vicinity, or downstream of the plant. Therefore, AmerGen concludes that the impact of thermophilic organisms is SMALL and does not warrant mitigation.

4.13 ELECTRIC SHOCK FROM TRANSMISSION-LINE-INDUCED CURRENTS

NRC

The environmental report must contain an assessment of the impact of the proposed action on the potential shock hazard from transmission lines "...[i]f the applicant's transmission lines that were constructed for the specific purpose of connecting the plant to the transmission system do not meet the recommendations of the National Electric Safety Code for preventing electric shock from induced currents…" 10 CFR 51.53(c)(3)(ii)(H)

"…Electrical shock resulting from direct access to energized conductors or from induced charges in metallic structures have not been found to be a problem at most operating plants and generally are not expected to be a problem during the license renewal term. However, site-specific review is required to determine the significance of the electric shock potential at the site…." 10 CFR 51, Subpart A, Table B 1, Issue 59

NRC made impacts of electric shock from transmission lines a Category 2 issue because, without a review of each plant's transmission line conformance with the National Electrical Safety Code (NESC) criteria (IEEE 1997), NRC could not determine the significance of the electric shock potential. This section provides an analysis of the TMI-1 transmission lines in conforming with the NESC standard.

Production of Induced Currents

Objects located near transmission lines can become electrically charged due to their immersion in the lines' electric field. This charge results in a current that flows through the object to the ground. The current is called "induced" because there is no direct connection between the line and the object. The induced current can also flow to the ground through the body of a person who touches the object. An object that is insulated from the ground can actually store an electrical charge, becoming what is called "capacitively charged." A person standing on the ground and touching a vehicle or a fence receives an electrical shock due to the sudden discharge of the capacitive charge through the person's body to the ground. After the initial discharge, a steady-state current can develop, the magnitude of which depends on several factors, including the following:

- the strength of the electric field which, in turn, depends on the voltage of the transmission line as well as its height and geometry;
- the size of the object on the ground; and
- the extent to which the object is grounded.

In 1977, the NESC adopted a provision that describes how to establish minimum vertical clearances to the ground for electric lines having voltages exceeding 98-kilovolt alternating current to ground. The clearance must limit the induced current due to electrostatic effects to 5 milliamperes if the largest anticipated truck, vehicle, or equipment were short-circuited to ground.

By way of comparison, the setting of ground fault circuit interrupters used in residential wiring (special breakers for outside circuits or those with outlets around water pipes) is 4 to 6 milliamperes.

TMI-1 Transmission Lines

As described in Section 3.1.3, there are four 230-kilovolt lines specifically constructed to distribute power from TMI-1 to the electric grid:

- Line No. 1051 – TMI-1 Plant to Jackson Substation
- Line No. 1091 - TMI-1 Plant to Middletown Junction
- Line No. 1092 – TMI-1 Plant to Middletown Junction
- Line from TMI-1 Plant to the 500-kV Substation

Induced Current Analysis

This analysis of the TMI-1 transmission lines is based on computer modeling of induced current under the line. The initial step of the analysis was identification of the line/road crossings to be analyzed. Only paved roads and highways were considered in the analysis; minor roads, i.e., “dirt” or service road crossings, were not included. The electric field strength and subsequently the induced current were then calculated for the transmission line at each location.

The electric field strength and induced current were calculated using a computer code called ACDCLINE, produced by the Electric Power Research Institute. The results of this computer program have been field-verified through actual electric field measurements by several utilities. The input parameters included design features of the limiting-case scenario and the NESC requirement that line sag be determined at a minimum conductor temperature of 120°F. The conductor sag measurements were taken from plan-and-profile drawings for the four lines, and the sag dimensions had been determined at a conservative temperature of 212°F. For analysis purposes, the maximum vehicle size under the lines is considered to be a tractor-trailer of 8.5 feet wide, 12 feet average height, and 65 feet long.

Analysis Results

The analytical results for each line are summarized in Table 4.13-1. The analysis determined that the maximum values for the four transmission lines are in compliance with the NESC limit and well below the NESC limit of 5 milliamperes. As shown in the table, the highest induced current was calculated to be 2.09 millamperes for Line No. 1092.

FirstEnergy Corporation, owners and operators of the transmission lines, conduct surveillance and maintenance to assure that design ground clearances will not change. These procedures include routine inspection by aircraft on a regular basis. The aerial patrols of all corridors include checks for encroachments, broken conductors, broken or leaning structures, and signs of burnt trees, any of which would be evidence of clearance problems. Ground inspections include examination for clearance at questionable locations, integrity of structures, and surveillance for dead or diseased trees that might fall on the transmission line. Problems noted during any inspection are brought to the attention of the appropriate organizations for corrective action.

As a result of this analysis performed in accordance with the requirements of 10 CFR 51, AmerGen concludes that electric shock is of SMALL significance for the TMI-1 transmission lines because the magnitude of the induced currents does not exceed the NESC standard. Mitigation measures are not warranted because there is adequate clearance between energized conductors and the ground. The conclusions on this issue will remain valid into the future, provided there are no changes in line use, voltage, and maintenance practices and no changes in land use under the line.

4.14 HOUSING IMPACTS

4.14.1 HOUSING – REFURBISHMENT

NRC

The environmental report must contain "...[a]n assessment of the impact of the proposed action on housing availability…" 10 CFR 51.53(c)(3)(ii)(I)

"…Housing impacts are expected to be of small significance at plants located in a medium or high population area and not in an area where growth control measures that limit housing development are in effect. Moderate or large housing impacts of the workforce associated with refurbishment may be associated with plants located in sparsely populated areas or areas with growth control measures that limit housing development…." 10 CFR 51, Subpart A, Table B-1, Issue 63

"The impacts on housing are considered to be of small significance when a small and not easily discernible change in housing availability occurs, generally as a result of a very small demand increase or a very large housing market. Increases in rental rates or housing values in these areas would be expected to equal or slightly exceed the statewide inflation rate. No extraordinary construction or conversion of housing would occur where small impacts are foreseen." (NRC 1996)

NRC made housing impacts a Category 2 issue because impact magnitude depends on local conditions that NRC could not predict for all plants at the time of GEIS publication (NRC 1996). Local conditions that need to be ascertained are: (1) population categorization as small, medium, or high, (2) applicability of growth control measures, (3) the size and growth rate of the housing market.

In the GEIS, Section 3.7.2 (NRC 1996), NRC states that the potential for refurbishment-related impacts to housing would be caused by increased staffing. Further, NRC states that impacts on housing would be considered to be of small significance when a small and not easily discernible change in housing availability occurs, generally as a result of a very small demand increase or a very large housing market.

In 10 CFR 51, Subpart A, Appendix B, Table B-1, NRC concluded that impacts to housing are expected to be of small significance at plants located in high population areas where growth control measures are not in effect.

The maximum impact to area housing was assessed using the following assumptions: (1) all direct jobs would be filled by in-migrating residents, (2) the residential distribution of the workers would resemble that of the original construction workforce, Dauphin and Lancaster Counties, (3) refurbishment workers that could not find temporary housing within Dauphin and Lancaster Counties would find temporary housing in other counties within the 50-mile radius, and (4) each new direct job created would represent one housing unit. AmerGen's estimate of 900 refurbishment employees (Section 3.4) could generate the demand for 900 housing units.

As described in Section 2.6, TMI-1 is located in a high population area. As noted in Section 2.8, the two counties surrounding the plant are not subject to growth control measures that limit housing development. Additionally, the 2000 population of the 50-mile radius was 2,546,479 and the state had an average of 2.48 persons per household (USCB 2000), suggesting the existence of approximately 1 million housing units. Hotels and motels in the vicinity, especially within the Harrisburg-Carlisle, PA MSA, provide temporary housing opportunities.

With the amount of temporary and permanent housing available and the absence of growth control measures, this demand would not create a discernible change in housing availability, rental rates or housing values, or spur housing construction or conversion in the plant vicinity or region. Therefore, AmerGen concludes that impacts to housing availability resulting from refurbishment-related population growth would be SMALL and would not warrant mitigation.

4.14.2 HOUSING – LICENSE RENEWAL TERM

NRC

The environmental report must contain "...[a]n assessment of the impact of the proposed action on housing availability…" 10 CFR 51.53(c)(3)(ii)(I)

"…Housing impacts are expected to be of small significance at plants located in a medium or high population area and not in an area where growth control measures that limit housing development are in effect. Moderate or large housing impacts of the workforce associated with refurbishment may be associated with plants located in sparsely populated areas or areas with growth control measures that limit housing development…." 10 CFR 51, Subpart A, Table B-1, Issue 63

"...[S]mall impacts result when no discernible change in housing availability occurs, changes in rental rates and housing values are similar to those occurring statewide, and no housing construction or conversion occurs…." (NRC 1996)

NRC made housing impacts a Category 2 issue because impact magnitude depends on local conditions that NRC could not predict for all plants at the time of GEIS publication (NRC 1996). Local conditions that need to be ascertained are: (1) population categorization as small, medium, or high and (2) applicability of growth control measures.

In 10 CFR 51, Subpart A, Appendix B, Table B-1, NRC concluded that impacts to housing are expected to be of small significance at plants located in high population areas where growth control measures are not in effect.

The maximum impact to area housing was calculated using the following assumptions: (1) all direct jobs would be filled by in-migrating residents; (2) the residential distribution of new residents would be similar to current operations worker distribution; and (3) each new direct job created would represent one housing unit. AmerGen's estimate of 60 license renewal employees (Section 3.4) could generate the demand for 60 housing units.

As described in Section 2.6, TMI-1 is located in a high population area. As noted in Section 2.8, Dauphin and Lancaster Counties are not subject to growth control measures that limit housing development. Additionally, in an area which has a population within a 50-mile radius of approximately 2,546,479 and a state average of 2.48 persons per household (USCB 2000), suggesting the existence of approximately one million housing units, it is reasonable to conclude that this demand would not create a discernible change in housing availability, rental rates or housing values, or spur housing construction or conversion. AmerGen concludes that impacts to housing availability resulting from plant-related population growth would be SMALL and would not warrant mitigation.

4.15 PUBLIC WATER SUPPLY

4.15.1 PUBLIC WATER SUPPLY – REFURBISHMENT

NRC

The environmental report must contain "…an assessment of the impact of population increases attributable to the proposed project on the public water supply." 10 CFR 51.53(c)(3)(ii)(I)

"…An increased problem with water shortages at some sites may lead to impacts of moderate significance on public water supply availability…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 65

"Impacts on public utility services are considered small if little or no change occurs in the ability to respond to the level of demand and thus there is no need to add capital facilities. Impacts are considered moderate if overtaxing of facilities during peak demand periods occurs. Impacts are considered large if existing service levels (such as quality of water and sewage treatment) are substantially degraded and additional capacity is needed to meet ongoing demands for services." (NRC 1996)

NRC made public utility impacts a Category 2 issue because an increased problem with water availability, resulting from pre-existing water shortages, could occur in conjunction with plant demand and plant-related population growth (NRC 1996). Local information needed would include: (1) a description of water shortages experienced in the area, and (2) an assessment of the public water supply system's available capacity.

NRC's analysis of impacts to the public water supply system considered both plant demand and plant-related population growth demands on local water resources. As stated in Section 2.3, the plant does not use water from a public water system. Therefore, there would be no plant demand-related impacts to the public water supply.

As such, the following discussion focuses on impacts of refurbishment on local public utilities, and the assumption that TMI-1 would add up to 900 employees during a 70-day period for refurbishment activities, as indicated in Section 3.4. Section 2.6 describes the TMI-1 regional demography. Section 2.9 describes the public water supply systems in the area, their permitted capacities, and current demands.

The maximum impact to area public water supplies was calculated using the following assumptions: (1) all direct jobs would be filled by in-migrating residents, (2) the residential distribution of the majority of the refurbishment work force would be similar to that of the original construction work force, Dauphin and Lancaster Counties, (3) refurbishment-related workers that could not find temporary housing within Dauphin and Lancaster Counties would find temporary housing in other counties within the 50-mile radius; and (4) refurbishment-related workers would not bring families due to the temporary nature of the refurbishment projects (i.e. 70 days or less).

The impact to the local water supply systems from plant-related population growth can be determined by calculating the amount of water that would be required by these individuals. The average American uses about 90 gpd for personal use (USEPA 2003). As described in Section 3.4, AmerGen estimates an additional 900 employees. The plant-related population increase could require an additional 81,000 gpd (900 people multiplied by 90 gpd) in an area where the excess public water supply capacity is approximately 21 million gallons per day from the Harrisburg Municipal Water Authority and the City of Lancaster, alone (see Tables 2.9-1 and 2.9-2). Of the 6 major water suppliers in Dauphin and Lancaster Counties, there are no suppliers for which demand exceeds supply. Additionally, TMI-1 operates an on-site sewage treatment facility with adequate capacity to accommodate the temporary increase of refurbishment employees. If it is assumed that this increase in population would be consistent with original construction work force trends (i.e., temporarily residing in Dauphin and Lancaster Counties), the increase in water demand would not create shortages in capacity of the water supply systems in these communities. AmerGen concludes that impacts resulting from plant-related population growth to public water supplies would be SMALL, requiring no additional capacity and not warranting mitigation.

4.15.2 PUBLIC WATER SUPPLY – LICENSE RENEWAL TERM

NRC

The environmental report must contain "…an assessment of the impact of population increases attributable to the proposed project on the public water supply." 10 CFR 51.53(c)(3)(ii)(I)

"…An increased problem with water shortages at some sites may lead to impacts of moderate significance on public water supply availability…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 65

"Impacts on public utility services are considered small if little or no change occurs in the ability to respond to the level of demand and thus there is no need to add capital facilities. Impacts are considered moderate if overtaxing of facilities during peak demand periods occurs. Impacts are considered large if existing service levels (such as quality of water and sewage treatment) are substantially degraded and additional capacity is needed to meet ongoing demands for services." (NRC 1996)

NRC made public utility impacts a Category 2 issue because an increased problem with water availability, resulting from pre-existing water shortages, could occur in conjunction with plant demand and plant-related population growth (NRC 1996). Local information needed would include: (1) a description of water shortages experienced in the area, and (2) an assessment of the public water supply system's available capacity.

NRC's analysis of impacts to the public water supply system considered both plant demand and plant-related population growth demands on local water resources. As stated in Section 2.3, the plant does not use water from a public water system. Therefore, there would be no plant demand-related impacts to the public water supply.

As such, the following discussion focuses on impacts of continued operations on local public utilities and the assumption that TMI-1 would add up to 60 additional employees during the period of extended operation for license renewal activities. As Section 3.4 indicates, AmerGen analyzed a hypothetical 60-person increase in TMI-1 employment attributable to license renewal. Section 2.6 describes the TMI-1 regional demography. Section 2.9 describes the public water supply systems in the area, their permitted capacities, and current demands.

The maximum impact to local water supply systems was assessed using the following assumptions: (1) all direct jobs would be filled by in-migrating residents and (2) the residential distribution of the workers would resemble that of the current operations workforce. The impact can be determined by calculating the amount of water that would be required by these individuals. The average American uses about 90 gpd for personal use (USEPA 2003). As described in Section 3.4, TMI-1 estimates an additional 60 employees, which could result in a population increase of 149 in the area (60 jobs multiplied by 2.48, which is the average number of persons per household in Pennsylvania [USCB 2000]). Using this consumption rate, the plant-related population increase could require an approximate additional 13,410 gpd

(149 people multiplied by 90 gpd) in an area where the excess public water supply capacity is approximately 21 million gallons per day from the Harrisburg Municipal Water Authority and the City of Lancaster (see Tables 2.9-1 and 2.9-2). Of the 6 major water suppliers in Dauphin and Lancaster Counties, there are no suppliers for which demand exceeds supply. If it is assumed that this increase in population would be consistent with current employee trends (i.e., 71 percent in Dauphin and Lancaster Counties), the increase in water demand would not create shortages in capacity of the water supply systems in these communities. AmerGen concludes that impacts resulting from plant-related population growth to public water supplies would be SMALL, requiring no additional capacity and not warranting mitigation.

4.16 EDUCATION

4.16.1 EDUCATION – REFURBISHMENT

NRC

The environmental report must contain "…[a]n assessment of the impact of the proposed action on…public schools (impacts from refurbishment activities only) within the vicinity of the plant…." 10 CFR 51.53(c)(3)(ii)(I)

"…Most sites would experience impacts of small significance but larger impacts are possible depending on site- and project-specific factors…." 10 CFR 51, Subpart A, Table B-1, Issue 66

"…[S]mall impacts are associated with project-related enrollment increases of 3 percent or less. Impacts are considered small if there is no change in the school systems' abilities to provide educational services and if no additional teaching staff or classroom space is needed. Moderate impacts are generally associated with 4 to 8 percent increases in enrollment. Impacts are considered moderate if a school system must increase its teaching staff or classroom space even slightly to preserve its pre-project level of service….Large impacts are associated with project-related enrollment increases above 8 percent…." (NRC 1996)

NRC made refurbishment-related impacts to education a Category 2 issue because site- and project-specific factors determine the significance of impacts (NRC 1996). Local factors to be ascertained include: (1) project-related enrollment increases and (2) status of the student/teacher ratio.

As stated in Section 3.4, AmerGen estimates that a maximum of 900 construction workers would be required for a maximum of 70 days for a steam generator replacement. This number of construction workers resembles an outage workforce, as it falls near the range (200 to 900 workers per reactor unit) reported in the GEIS for additional maintenance workers during a normal refueling outage (NRC 1996). The duration of the construction project would be within the range of a refueling outage. Anecdotal evidence from refueling outages at many plants in the U.S. suggests that outage workforces of this size and duration generally do not relocate families to the plant site region. Therefore, AmerGen estimates that few to no children would relocate to the region and that impacts on public schools would be SMALL and mitigation would not be warranted.

4.16.2 EDUCATION – LICENSE RENEWAL TERM

NRC made license renewal-related impacts to education a Category 1 issue. Therefore, an analysis is not needed.

4.17 OFFSITE LAND USE

4.17.1 OFFSITE LAND USE - REFURBISHMENT

NRC

The environmental report must contain "…an assessment of the impact of the proposed action on... land-use... (impacts from refurbishment activities only) within the vicinity of the plant…." 10 CFR 51.53(c)(3)(ii)(I)

"…Impacts may be of moderate significance at plants in low population areas…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 68

"…[I]f plant-related population growth is less than 5 percent of the study area's total population, off-site land-use changes would be small, especially if the study area has established patterns of residential and commercial development, a population density of at least 60 persons per square mile, and at least one urban area with a population of 100,000 or more within 50 miles…." (NRC 1996)

NRC made impacts to offsite land use as a result of refurbishment activities a Category 2 issue because land-use changes could be considered beneficial by some community members and adverse by others. Local conditions to be ascertained include: (1) plant-related population growth, (2) patterns of residential and commercial development, and (3) proximity to an urban area with a population of at least 100,000 (NRC 1996).

In the GEIS, Section 3.7.5 (NRC 1996), NRC stated that, if refurbishment-related population growth is less than 5 percent of the study area's total population, off-site land-use changes would be small, especially if the study area has established patterns of residential and commercial development, a population density of at least 60 persons per square mile, and at least one urban area with a population of 100,000 or more within 50 miles.

As stated in Section 2.6.1, Demography, the 2000 population of the 50-mile radius was 2,546,479, the population density was 325 persons per square mile within the 20-mile radius, and the 2000 population of Dauphin County was 251,798. The Harrisburg-Carlisle, PA MSA, Lancaster, PA MSA, York-Hanover, PA MSA and Reading, PA MSA are the largest urban areas within a 50-mile radius of the plant, and had 2000 populations of 509,074; 470,658; 381,751; and 373,638, respectively.

A refurbishment workforce of 900 would represent 0.4 percent increase in the population of Dauphin County and an even smaller percent increase (0.2 percent or less) in the populations of any one of the largest urban areas within the 50-mile region. As stated in Section 2.8, Land Use Planning, Dauphin and Lancaster counties are not subject to growth control measures that limit housing development. Therefore, AmerGen concludes that impacts to off-site land use resulting from refurbishment would be SMALL and would not warrant mitigation.

4.17.2 OFFSITE LAND USE - LICENSE RENEWAL TERM

NRC

The environmental report must contain "…[a]n assessment of the impact of the proposed action on…land-use…." 10 CFR 51.53(c)(3)(ii)(I)

"Significant changes in land use may be associated with population and tax revenue changes resulting from license renewal." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 69

"…[I]f plant-related population growth is less than five percent of the study area's total population, off-site land-use changes would be small…." (NRC 1996, Section 3.7.5)

"…[I]f the plant's tax payments are projected to be small relative to the community's total revenue, new tax-driven land-use changes during the plant's license renewal term would be small, especially where the community has preestablished patterns of development and has provided adequate public services to support and guide development." (NRC 1996, Section 4.7.4.1)

NRC made impacts to offsite land use during the license renewal term a Category 2 issue, because land-use changes may be perceived as beneficial by some community members and detrimental by others. Therefore, NRC could not assess the potential significance of site-specific offsite land-use impacts (NRC 1996, Section 4.7.4.2). Site-specific factors to consider in an assessment of land-use impacts include: (1) the size of plant-related population growth compared to the area's total population, (2) the size of the plant's tax payments relative to the community's total revenue, (3) the nature of the community's existing land-use pattern, and (4) the extent to which the community already has public services in place to support and guide development.

The GEIS presents an analysis of offsite land use for the renewal term that is characterized by two components: population-driven and tax-driven impacts (NRC 1996, Section 4.7.4.1).

<u>**Population-Related Impacts**</u>

Based on the GEIS case-study analysis, NRC concluded that all new population-driven land-use changes during the license renewal term at all nuclear plants would be small. Population growth caused by license renewal would represent a much smaller percentage of the local area's total population than the percent change represented by operations-related growth (NRC 1996, Section 3.7.3).

<u>**Tax-Revenue-Related Impacts**</u>

Determining tax-revenue-related land use impacts is a two-step process. First, the significance of the plant's tax payments on taxing jurisdictions' tax revenues is evaluated. Then, the impact of the tax contribution on land use within the taxing jurisdiction's boundaries is assessed.

Tax Payment Significance

NRC has determined that the significance of tax payments as a source of local government revenue would be large if the payments are greater than 20 percent of revenue, moderate if the payments are between 10 and 20 percent of revenue, and small if the payments are less than 10 percent of revenue (NRC 1996).

Land Use Significance

NRC defined the magnitude of land-use changes as follows (NRC 1996):

SMALL - very little new development and minimal changes to an area's land-use pattern.

MODERATE - considerable new development and some changes to land-use pattern.

LARGE - large-scale new development and major changes in land-use pattern.

NRC further determined that, "…[I]f the plant's tax payments are projected to be medium to large relative to the community's total revenue, new tax-driven land-use changes would be moderate. This is most likely to be true where the community has no preestablished patterns of development (i.e., land use plans or controls) or has not provided adequate public services to support and guide development in the past, especially infrastructure that would allow industrial development (NRC 1996).

Tax Impacts

Table 2.7-1 provides a comparison of the 2000 through 2005 tax payments made by AmerGen to Dauphin County, Lower Dauphin School District and Londonderry Township and the tax revenues for each of these taxing bodies. Using NRC's criteria, Amergen's property tax payments were of small significance to Dauphin County (0.2 percent), Lower Dauphin School District (1.7 percent) and Londonderry Township (0.3 percent).

Land Use Impacts

As stated in Sections 2.6 and 2.9, Dauphin County experienced significant growth over the last several decades. From 1980 to 1990, the county's growth rate of 2 percent outpaced the State of Pennsylvania growth rate that was relatively stagnant at 0.2 percent. From 1990 to 2000, the population growth of the county remained positive at 5.9 percent. During the same period, the state population grew at a rate of 3.4 percent.

Dauphin County's growth can be attributed to the development of the southwest and southeast sections of the county.

Dauphin County, Lower Dauphin School District and Londonderry Township receive TMI-1 property tax payments. Although the county has experienced growth over the last three decades, the majority of land use remains rural (87 percent). Dauphin County uses comprehensive land use plans and zoning and subdivision ordinances to guide development. These plans and ordinances have been in place for several decades. The ordinances promote the public health, safety, and general welfare of residents; protect agricultural land from urban sprawl; and provide a basis for the orderly development. The ordinances require building permits, conditional use permits, plat development, zoning district controls, and variance requests. In the early 1990s, the county adopted formal growth control measures to promote growth in areas with existing infrastructure and development.

Conclusion

The TMI-1's property taxes are of small significance to Dauphin County and the land use changes in the county have been minimal with less than 13 percent of the county developed. Population growth has been attributed to the larger influence of the surrounding metropolitan areas and advancements in the transportation network. The county has a preestablished pattern of development with controls for future development and has been able to provide the infrastructure needed to accommodate this growth. The nuclear plant's presence is not expected to directly attract support industries and commercial development or to encourage or deter residential development. Because population growth related to the license renewal of TMI-1 is expected to be small and there would be no new tax impacts to Dauphin County, the renewal of AmerGen's license would have a continued SMALL but financially beneficial impact on land use in Dauphin County. Therefore, mitigation would not be warranted.

4.18 TRANSPORTATION

4.18.1 TRANSPORTATION – REFURBISHMENT

NRC

The environmental report must "...assess the impact of highway traffic generated by the proposed project on the level of service of local highways during periods of license renewal refurbishment activities and during the term of the renewed license." 10 CFR 51.53(c)(3)(ii)(J)

"…Transportation impacts…are generally expected to be of small significance. However, the increase in traffic associated with additional workers and the local road and traffic control conditions may lead to impacts of moderate or large significance at some sites…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 70

Small impacts would be associated with U.S. Transportation Research Board Level of Service A, having the following condition: "…Free flow of the traffic stream; users are unaffected by the presence of others." and Level of Service B, having the following condition: "…Stable flow in which the freedom to select speed is unaffected but the freedom to maneuver is slightly diminished…." (NRC 1996)

NRC made impacts to transportation a Category 2 issue, because impact significance is determined primarily by road conditions existing at the time of refurbishment, which NRC could not forecast for all facilities (NRC 1996). Local road conditions to be ascertained are: (1) level of service conditions and (2) incremental increases in traffic associated with the refurbishment work force.

The following discussion focuses primarily on transportation impacts from the addition during the 70-day steam generator replacement outage of up to 900 additional employees. However, transportation impacts also may occur at some locations along the transfer route of the replacement steam generators from the U.S. port of call (i.e., Baltimore, Philadelphia, or Newark) to the TMI-1 site. As section 3.2 explains, a final option has not been selected for the transfer activities. Notwithstanding, some options being considered may involve temporary removal from the route of interferences, such as low-hanging overhead lines. Movement of wide and heavy loads over roadways are also possible. Such activities may result in temporary, localized, slowing of traffic, or detours. In any case, applicable prior approvals (see Table 9.1-3) would be obtained at the appropriate time from federal, state, and local agencies.

The maximum impact to transportation in the area of the TMI-1 site as a result of additional employees during the 70-day outage was analyzed using the following assumptions: (1) all direct jobs would be filled by in-migrating residents, (2) the residential distribution of the majority of the refurbishment work force would be similar to that of the original construction work force (Dauphin and Lancaster Counties), (3) refurbishment-related workers that could not find temporary housing within Dauphin and Lancaster Counties would find temporary housing in other counties within the 50-mile radius; and (4) each new direct job created would represent one additional vehicle on area roadways.

In the GEIS, NRC used the Transportation Research Board's level of service (LOS) definitions to assess significance levels of transportation impacts. LOS is a qualitative measure describing operational conditions within a traffic stream and their perception by motorists (NRC 1996). AmerGen employed the same definitions to analyze transportation impacts. According to NRC criteria, LOS A and B are associated with small impacts because the operation of individual users is not substantially affected by the presence of other users (NRC 1996, Section 3.7.4.2). LOS data are available for select roads in Dauphin County, specifically State Highway (SH)-441 (Table 2.9-3, Roadway Information). The greatest concentration of refurbishment-related workforce traffic would be found on SH-441 between Interstate 76 and SH-241. Dauphin County has determined that the LOS determinations for SH-441 on either side of the TMI-1 site entrances are either A or B. Traffic counts on SH-441, south of TMI-1's southern entrance in Lancaster County, are similar to those reported in Dauphin County. Therefore, AmerGen reasonably assumes that LOS determinations on this portion of SH-441 may be similar to those in Dauphin County.

As stated previously, the TMI-1 site has two entrances. The entrance to the north is used by the operating work force. The entrance to the south is used by a limited number of operational employees working on the southern portion of the station and construction and outage workforces. During the refurbishment projects, construction workers would use the southern entrance to the site. This would alleviate potential congestion problems at the northern site entrance.

The addition of 900 workers on SH-441 would not create discernible change in traffic flows because the LOS determinations for SH-441, both directly north and south of the plant, are either A or B. Given these employment projections, the average number of vehicles per day currently using the surrounding roads to TMI-1, and the LOS determinations of A and B on SH-441 in Dauphin County (Table 2.9-3), AmerGen concludes that impacts to transportation would be SMALL and mitigative measures would be unwarranted.

4.18.2 TRANSPORTATION – LICENSE RENEWAL TERM

NRC

The environmental report must "...assess the impact of highway traffic generated by the proposed project on the level of service of local highways during periods of license renewal refurbishment activities and during the term of the renewed license." 10 CFR 51.53(c)(3)(ii)(J)

"…Transportation impacts…are generally expected to be of small significance. However, the increase in traffic associated with additional workers and the local road and traffic control conditions may lead to impacts of moderate or large significance at some sites…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 70

Small impacts would be associated with U.S. Transportation Research Board Level of Service A, having the following condition: "…Free flow of the traffic stream; users are unaffected by the presence of others." and Level of Service B, having the following condition: "…Stable flow in which the freedom to select speed is unaffected but the freedom to maneuver is slightly diminished…." (NRC 1996)

NRC made impacts to transportation a Category 2 issue, because impact significance is determined primarily by road conditions existing at the time of license renewal, which NRC could not forecast for all facilities (NRC 1996). Local road conditions to be ascertained are: (1) level of service conditions and (2) incremental increases in traffic associated license renewal staff.

The following discussion focuses on impacts of continued operations on transportation and the assumption that TMI-1 would add up to 60 additional employees during the period of extended operations. AmerGen's TMI-1 workforce includes approximately 526 permanent and 170 contract employees. On a 24-month cycle, as many as 1,400 additional workers join the permanent workforce during a refueling outage, which typically lasts approximately 20 to 30 days. AmerGen's projection of 60 additional employees associated with license renewal for TMI-1 represents an 8.7 percent increase in the current number of permanent and contract employees and an even smaller percentage of employees present onsite during a refueling outage.

In the GEIS, NRC used the Transportation Research Board's LOS definitions to assess significance levels of transportation impacts. LOS is a qualitative measure describing operational conditions within a traffic stream and their perception by motorists (NRC 1996). AmerGen employed the same definitions to analyze transportation impacts. According to NRC criteria, LOS A and B are associated with small impacts because the operation of individual users is not substantially affected by the presence of other users (NRC 1996, Section 3.7.4.2). LOS data are available for select roads in Dauphin County, specifically SH-441 (Table 2.9-3, Roadway Information). The greatest concentration of operations-related workforce traffic would be found on SH-441 between Interstate 76 and SH-241. Dauphin County has determined that the LOS determinations for SH-441 on either side of the TMI-1 site entrances are either A or B. Traffic counts on SH-441, south of TMI-1's southern entrance in Lancaster

County are similar to those reported in Dauphin County. Therefore, AmerGen reasonably assumes that LOS determinations on this portion of SH-441 may be similar to those in Dauphin County.

As stated previously, the TMI-1 site has two entrances. The entrance to the north is used by the operating work force. The entrance to the south is used by a limited number of operational employees working on the southern portion of the station and construction and outage workforces. During the outages and refurbishment projects, construction and outage workers would use the southern entrance to the plant. The 60 additional license renewal workers would use the northern entrance. This would alleviate any potential congestion problems at the northern site entrance.

The addition of 60 workers on SH-441 would not create discernible change in traffic flows because the LOS determinations for SH-441, both directly north and south of the plant, are either A or B. Given these employment projections, the average number of vehicles per day currently using the surrounding roads to TMI-1, and the LOS determinations of A and B on SH-441 in Dauphin County (Table 2.9-3), AmerGen concludes that impacts to transportation would be SMALL and mitigative measures would be unwarranted.

4.19 HISTORIC AND ARCHAEOLOGICAL RESOURCES

4.19.1 HISTORIC AND ARCHAEOLOGICAL RESOURCES – REFURBISHMENT

NRC

The environmental report must contain an assessment of "…whether any historic or archaeological properties will be affected by the proposed project." 10 CFR 51.53(c)(3)(ii)(K)

"Generally, plant refurbishment and continued operation are expected to have no more than small adverse impacts on historic and archaeological resources. However, the National Historic Preservation Act requires the Federal agency to consult with the State Historic Preservation Officer to determine whether there are properties present that require protection." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 71

"Sites are considered to have small impacts to historic and archaeological resources if (1) the State Historic Preservation Officer (SHPO) identifies no significant resources on or near the site; or (2) the SHPO identifies (or has previously identified) significant historic resources but determines they would not be affected by plant refurbishment, transmission lines, and license-renewal term operations and there are no complaints from the affected public about altered historic character; and (3) if the conditions associated with moderate impacts do not occur." (NRC 1996)

NRC made impacts to historic and archaeological resources a Category 2 issue, because determinations of impacts to historic and archaeological resources are site-specific in nature and the National Historic Preservation Act mandates that impacts must be determined through consultation with the State Historic Preservation Officer (SHPO) (NRC 1996).

The Final Environmental Statement (FES) related to operation of the Three Mile Island Nuclear Station, Units 1 and 2 reports that the Advisory Council on Historic Preservation, the United States Department of the Interior, and the Pennsylvania Historical and Museum Commission (PHMC) were consulted by the US Atomic Energy Commission (AEC) regarding issuance of the initial operating licenses for the units. Comments from those agencies were included in the FES and indicated that the operation of TMI-1 would have no significant adverse effect on cultural resources in the area (AEC 1972).

Several cultural resource investigations have been conducted on the Island, including an archaeological survey and excavation by the Pennsylvania Historical and Museum Commission in 1967 (PHMC 1977). Results of those investigations indicate that Three Mile Island has had a long history of occupation and utilization. Cultures from the prehistoric Early Archaic through the historic Susquehannock have used the island.

AmerGen has identified sites currently listed on the National Register and determined eligible for listing on the National Register within the site vicinity (see Table 2.11-1).

Also, AmerGen has corporate procedures that protect cultural resources on all AmerGen plant sites and has instituted those procedures at TMI-1, as well.

Currently, AmerGen is not aware of any historic or archaeological resources that have been affected by TMI-1 activities. For the steam generator replacement project, AmerGen has no plans to construct permanent additional facilities or infrastructure except for the steam generator storage facility. This facility will be constructed in a previously disturbed area on site. Construction activities will be governed by AmerGen's corporate procedure that ensure the protection of cultural resources (Exelon 2007). Additional refurbishment traffic on area roadways is not expected to affect cultural resources. Therefore, AmerGen concludes that impacts from refurbishment activities would be SMALL, and no mitigation would be warranted.

Through correspondence with the Pennsylvania SHPO, AmerGen has obtained the Pennsylvania Bureau of Historic Preservation's concurrence that refurbishment activities would have no effect on historic and archaeological resources. Copies of the correspondence are presented in Appendix D.

4.19.2 HISTORIC AND ARCHAEOLOGICAL RESOURCES – LICENSE RENEWAL TERM

NRC

The environmental report must contain an assessment of "…whether any historic or archaeological properties will be affected by the proposed project." 10 CFR 51.53(c)(3)(ii)(K)

"Generally, plant refurbishment and continued operation are expected to have no more than small adverse impacts on historic and archaeological resources. However, the National Historic Preservation Act requires the Federal agency to consult with the State Historic Preservation Officer to determine whether there are properties present that require protection." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 71

"Sites are considered to have small impacts to historic and archaeological resources if (1) the State Historic Preservation Officer (SHPO) identifies no significant resources on or near the site; or (2) the SHPO identifies (or has previously identified) significant historic resources but determines they would not be affected by plant refurbishment, transmission lines, and license-renewal term operations and there are no complaints from the affected public about altered historic character; and (3) if the conditions associated with moderate impacts do not occur." (NRC 1996)

NRC made impacts to historic and archaeological resources a Category 2 issue, because determinations of impacts to historic and archaeological resources are site-specific in nature and the National Historic Preservation Act mandates that impacts must be determined through consultation with the State Historic Preservation Officer (NRC 1996).

In the context of the National Historic Preservation Act, the NRC has determined that the Area of Potential Effect for a license renewal action is the area at the power plant site and its immediate environs which may be impacted by post-license renewal land disturbing activities specifically related to license renewal, regardless of ownership or control of the land of interest.

The FES related to operation of the Three Mile Island Nuclear Station, Units 1 and 2 reports that the Advisory Council on Historic Preservation, the United States Department of the Interior, and the Pennsylvania Historical and Museum Commission (PHMC) were consulted by the US Atomic Energy Commission (AEC) regarding issuance of the initial operating licenses for the units. Comments from those agencies were included in the FES and indicated that the operation of TMI-1 would have no significant adverse effect on cultural resources in the area (AEC 1972).

Several cultural resource investigations have been conducted on the Island, including an archaeological survey and excavation by the Pennsylvania Historical and Museum Commission in 1967 (PHMC 1977). Results of those investigations have indicated that Three Mile Island has had a long history of occupation and utilization. Cultures from the prehistoric Early Archaic through the historic Susquehannock have used the island.

AmerGen has identified sites currently listed on the National Register and determined eligible for listing on the National Register within the site vicinity. Also, AmerGen has corporate procedures that protect cultural resources on all AmerGen plant sites and has instituted those procedures at TMI-1 as well.

Currently, AmerGen is not aware of any historic or archaeological resources that have been affected by TMI-1 operations. Because AmerGen has no plans to construct additional facilities at TMI-1 related to license renewal and because any land-disturbing activities that would be required would be done under the auspices of AmerGen's corporate procedures that insure the protection of cultural resources (Exelon 2007), AmerGen concludes that operation of TMI-1 over the license renewal term would not impact cultural resources; hence, impacts would be SMALL, and no mitigation would be warranted.

Through correspondence with the Pennsylvania SHPO, AmerGen has obtained the Pennsylvania Bureau of Historic Preservation's concurrence that operation of TMI-1 during the term of license renewal activities would have no effect on historic and archaeological resources. Copies of the correspondence are presented in Appendix D.

4.20 SEVERE ACCIDENT MITIGATION ALTERNATIVES (SAMA)

NRC

The environmental report must contain a consideration of alternatives to mitigate severe accidents "…if the staff has not previously considered severe accident mitigation alternatives for the applicant's plant in an environmental impact statement or related supplement or in an environment assessment..." 10 CFR 51.53(c)(3)(ii)(L)

"…The probability weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to ground water, and societal and economic impacts from severe accidents are small for all plants. However, alternatives to mitigate severe accidents must be considered for all plants that have not considered such alternatives…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 76

Section 4.20 summarizes an analysis of alternative ways to mitigate the impacts of severe accidents at TMI-1. AmerGen prepared this severe accident mitigation alternatives (SAMA) analysis, the details of which are provided in Appendix E, with support from its parent company, Exelon. For this reason, AmerGen and Exelon are referred to interchangeably in Section 4.20 and Appendix E.

The term "accident" refers to any unintentional event (i.e., outside the normal or expected plant operation envelope) that results in the release or a potential for release of radioactive material to the environment. NRC categorizes accidents as "design basis" or "severe." Design basis accidents are those for which the risk is great enough that NRC requires plant design and construction to prevent unacceptable accident consequences. Severe accidents are those that NRC considers too unlikely to warrant design controls.

NRC concluded in its license renewal rulemaking that the unmitigated environmental impacts from severe accidents met its Category 1 criteria. However, NRC made consideration of mitigation alternatives a Category 2 issue because not all plants had completed ongoing regulatory programs related to mitigation (e.g., individual plant examinations and accident management). Site-specific information to be presented in the license renewal environmental report includes: (1) potential SAMAs; (2) benefits, costs, and net value of implementing potential SAMAs; and (3) sensitivity of analysis to changes in key underlying assumptions.

AmerGen maintains a probabilistic safety assessment (PSA) model to use in evaluating the most significant risks of radiological release from TMI-1 fuel into the reactor and from the reactor into the containment structure. For the SAMA analysis, AmerGen used the PSA model output as input to an NRC-approved consequence assessment code (MACCS2) that calculates economic costs and dose to the public from hypothesized releases from the containment structure into the environment. Then, using NRC regulatory analysis techniques, AmerGen calculated the monetary value of the unmitigated TMI-1 severe accident risk. The result represents the monetary value of the base risk of dose to the public and workers, offsite and onsite economic costs, and replacement power. This value became a cost/benefit-screening tool for potential SAMAs; a SAMA whose cost of implementation exceeded the base cost-risk value could be rejected as being not cost-beneficial.

AmerGen used industry, NRC, and TMI-1-specific information to create a list of 33 SAMAs for consideration. AmerGen analyzed this list to screen out any SAMAs that (1) would not apply to the TMI-1 design, (2) had already been implemented at TMI-1, or (3) would achieve results that AmerGen had already achieved at TMI-1 by other means. None of the SAMAs were screened based on these criteria. Hence, AmerGen prepared cost estimates for the 33 SAMAs and used the base risk value to screen out SAMAs that would not be cost-beneficial.

AmerGen calculated the cost-risk reduction that would be attributable to each of the remaining SAMAs (assuming SAMA implementation) and re-quantified the cost-risk value. The difference between the base cost-risk value and the SAMA-reduced cost-risk value became the averted cost-risk, or the value of implementing the SAMA.

AmerGen then performed a cost/benefit comparison for these SAMAs using this averted cost-risk value and the corresponding cost estimates for implementing the specific SAMA.

AmerGen performed additional sensitivity analyses to evaluate how the SAMA analysis would change if certain key parameters were changed. The results of the sensitivity analyses are discussed in Appendix E.

During AmerGen's TMI-1 SAMA analysis, certain errors were found in an NRC-sponsored code, SECPOP2000, which supports the MACCS2 code. The effect of these errors on the analysis has been evaluated, as described in Section E.7.6 of Appendix E, and incorporated into the conclusions reported below.

Based on the results of this SAMA analysis, AmerGen concludes that fifteen potentially cost-beneficial options exist to reduce plant risk that could be examined further, but none are related to managing the effects of plant aging during the period of extended operation. The potentially cost beneficial SAMAs will be considered for implementation through the established TMI-1 work management processes.

Table 4.13-1. Results of Induced Current Analysis.

Transmission Line	Voltage (kilovolts)	Maximum Induced Current (milliamperes)
Line No. 1051 – TMI-1 Plant to Jackson Substation	230	1.09
Line No. 1091 - TMI-1 Plant to Middletown Junction	230	1.38
Line No. 1092 – TMI-1 Plant to Middletown Junction	230	2.09
Line from TMI-1 Plant to the 500-kV Substation	230	1.33

Note: The TMI-1 Plant to the 500-kV Substation transmission line was designed to operate at 500 kilovolts, but it operates at 230 kilovolts.

4.21 REFERENCES

Note to reader: Some web pages cited in this document are no longer available, or are no longer available through the original URL addresses. Hard copies of cited web pages are available in AmerGen files. Some sites, for example the census data, cannot be accessed through their given URLs. The only way to access these pages is to follow queries on previous web pages. The complete URLs used by AmerGen have been given for these pages, even though they may not be directly accessible. Also, all references are specific to respective chapter.

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PHMC (Pennsylvania Historical and Museum Commission). 1977. “Early and Middle Woodland Campsites on Three Mile Island, Dauphin County, Pennsylvania.” Pennsylvania Historical and Museum Commission, William Penn Memorial Museum. Harrisburg, Pennsylvania. January.

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SRBC (Susquehanna River Basin Commission) 2005, Cowanesque Reservoir Water Storage Project Storing Water for Low Flows, Information Sheet. July 14.

USCB (U.S. Census Bureau). 2000. “State and County Quickfacts, Dauphin and Lancaster Counties, Pennsylvania.” Available online at http://quickfacts.census.gov/. Accessed August 3, 2006.

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Chapter 5

ASSESSMENT OF NEW AND SIGNIFICANT INFORMATION

5.1 DISCUSSION

NRC

"…The environmental report must contain any new and significant information regarding the environmental impacts of license renewal of which the applicant is aware." 10 CFR 51.53(c)(3)(iv)

The U.S. Nuclear Regulatory Commission (NRC) licenses the operation of domestic nuclear power plants and provides for license renewal, requiring a license renewal application that includes an environmental report (10 Code of Federal Regulations (CFR) 54.23). NRC regulations, 10 CFR 51, prescribe the environmental report content and identify the specific analyses the applicant must perform. In an effort to streamline the environmental review, NRC has resolved most of the environmental issues generically and only requires an applicant's analysis of the remaining issues.

While NRC regulations do not require an applicant's environmental report to contain analyses of the impacts of those Category 1 environmental issues that have been generically resolved [10 CFR 51.53(c)(3)(i)], the regulations do require that an applicant identify any new and significant information of which the applicant is aware [10 CFR 51.53(c)(3)(iv)]. The purpose of this requirement is to alert NRC staff to such information, so the staff can determine whether to seek the Commission's approval to waive or suspend application of the rule with respect to the affected generic analysis. NRC has explicitly indicated, however, that an applicant is not required to perform a site-specific validation of Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) conclusions (NRC 1996).

AmerGen Energy Company, LLC (AmerGen) expects that new and significant information would include:

- Information that identifies a significant environmental issue not covered in the GEIS and codified in the regulation, or
- Information that was not covered in the GEIS analyses and that leads to an impact finding different from that codified in the regulation.

NRC does not specifically define the term "significant." For the purpose of its review, AmerGen used guidance available in Council on Environmental Quality (CEQ) regulations. The National Environmental Policy Act authorizes CEQ to establish implementing regulations for federal agency use. NRC requires license renewal applicants to provide NRC with input, in the form of an environmental report, that NRC will use to meet National Environmental Policy Act requirements as they apply to license renewal (10 CFR 51.10).

CEQ guidance provides that federal agencies should prepare environmental impact statements for actions that would significantly affect the environment (40 CFR 1502.3), focus on significant environmental issues (40 CFR 1502.1), and eliminate from detailed study issues that are not significant [40 CFR 1501.7(a)(3)]. The CEQ guidance includes a lengthy definition of "significantly" that requires consideration of the context of the action and the intensity or severity of the impact(s) (40 CFR 1508.27). AmerGen considered that MODERATE or LARGE impacts, as defined by NRC, would be significant. Chapter 4 presents the NRC definitions of SMALL, MODERATE, and LARGE impacts.

The new and significant assessment that AmerGen conducted during preparation of this license renewal application included: (1) interviews with AmerGen and First Energy subject matter experts on the validity of the conclusions in the GEIS as they relate to Three Mile Island Generating Station Unit 1 (TMI-1), (2) an extensive review of documents related to environmental issues at TMI-1, (3) a review of correspondence with state and federal agencies to determine if the agencies had concerns relevant to their resource areas that had not been addressed in the GEIS, (4) a review of the results of TMI-1 environmental monitoring and reporting, as required by regulations and oversight of plant facilities and operations by state and federal regulatory agencies (i.e., the results of ongoing routine activities that could bring significant issues to AmerGen's attention), and (5) a review for issues relevant to the TMI-1 application of certain license renewal applications that have previously been submitted to the NRC by the operators of other nuclear plants.

As part of the assessment described above for new and significant information, AmerGen evaluated information about tritium in groundwater at the Three Mile Island Nuclear Station (Section 2.3). Based on that evaluation, AmerGen has concluded that TMI-1 is not contributing to changes in groundwater quality that would preclude current or future uses of the groundwater for the following reasons:

- The Susquehanna River acts as a boundary between the groundwater on Three Mile Island and groundwater in the rock of the Gettysburg formation on either side of the river.

- Under normal Station conditions, tritium levels in the groundwater do not exceed the EPA drinking water standard of 20,000 pCi/L.

- The Radiological Groundwater Protection Program (RGPP) at the Three Mile Island Nuclear Station has been shown to provide an effective warning system for releases of tritium to the groundwater from TMI-1 operations.

- Station response to RGPP reporting illustrates that timely corrective action is effective to remediate and control tritium releases to groundwater.

Hence, the contribution of TMI-1 operations during the license renewal period to the cumulative impacts of major activities on groundwater quality would be small.

In its entirety, AmerGen's assessment did not identify any new and significant information regarding the plant's environment or operations that would make any generic conclusion codified by the NRC for Category 1 issues not applicable to TMI-1, that would alter regulatory or GEIS statements regarding Category 2 issues or that would suggest any other measure of license renewal environmental impact.

5.2 REFERENCES

NRC (U.S. Nuclear Regulatory Commission). 1996. Public Comments on the Proposed 10 CFR 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response. Volumes 1 and 2. NUREG-1529. Washington, DC. May.

Chapter 6

SUMMARY OF LICENSE RENEWAL IMPACTS AND MITIGATING ACTIONS

6.1 LICENSE RENEWAL IMPACTS

AmerGen Energy Company, LLC (AmerGen) has reviewed the environmental impacts of renewing the Three Mile Island Nuclear Station Unit 1 (TMI-1) operating licenses and has concluded that impacts would be SMALL and would not require mitigation. This environmental report documents the basis for AmerGen's conclusion. Chapter 4 incorporates by reference Nuclear Regulatory Commission (NRC) findings for the 69 Category 1 issues that apply to TMI-1, all of which have impacts that are SMALL (Appendix A, Table A-1). The rest of Chapter 4 analyzes Category 2 issues, all of which are either not applicable or have impacts that are SMALL. Table 6.1-1 identifies the impacts that TMI-1 license renewal would have on resources associated with Category 2 issues.

6.2 MITIGATION

NRC

"The report must contain a consideration of alternatives for reducing adverse impacts…for all Category 2 license renewal issues…" 10 CFR 51.53(c)(3)(iii)

"The environmental report shall include an analysis that considers and balances…alternatives available for reducing or avoiding adverse environmental effects…" 10 CFR 51.45(c) as incorporated by 10 CFR 51.53(c)(2) and 10 CFR 51.45(c)

Impacts of license renewal and refurbishment activities have been predicted as SMALL and would not require mitigation. Current operations include monitoring activities that would continue during the license renewal term. AmerGen performs routine monitoring to ensure the safety of workers, the public, and the environment. These activities include gaseous and liquid radiological environmental monitoring in accordance with the TMI-1 operating license technical specifications issued by the NRC, non-radiological air emissions monitoring in accordance with air quality permits issued by the PADEP, groundwater monitoring in accordance with the TMI-1 Radiological Groundwater Protection Program, and water effluent monitoring in accordance with the National Pollutant Discharge Elimination System (NPDES) permit issued by the PADEP. These monitoring programs ensure that the plant's emissions and effluents are within regulatory limits and that unusual or off-normal emissions/discharges are quickly detected, thus mitigating potential impacts. Accordingly, AmerGen has concluded that additional mitigation measures are not warranted.

6.3 UNAVOIDABLE ADVERSE IMPACTS

NRC

The environmental report shall discuss any "...adverse environmental effects which cannot be avoided should the proposal be implemented..." 10 CFR 51.45(b)(2) as adopted by 10 CFR 51.53(c)(2)

This environmental report adopts by reference NRC findings for applicable Category 1 issues, including discussions of any unavoidable adverse impacts (Table A-1). AmerGen examined 21 Category 2 issues and identified the following unavoidable adverse impacts of license renewal and refurbishment activities:

- The Cooling Towers and their vapor plumes are visible from offsite. This visual impact will continue during the license renewal term.

- Procedures for the disposal of radioactive and nonradioactive wastes are intended to reduce adverse impacts from these sources to acceptably low levels. A small impact will occur as long as the plant is in operation. Solid radioactive wastes are a product of plant operations and permanent disposal of such materials is required.

- Operation of TMI-1 results in a very small increase in radioactivity in the air and water. However, fluctuations in natural background radiation are expected to exceed the small incremental increase in dose to the local population. Operation of TMI-1 also creates a very low probability of accidental radiation exposure to inhabitants of the area.

- Operations of TMI-1 results in consumptive use of Susquehanna River water. AmerGen is required to have plans for low-flow augmentation during drought conditions and participates in the Cowanesque Lake storage project.

- Land is required to store the old steam generator onsite pending disposal.

6.4 IRREVERSIBLE AND IRRETRIEVABLE RESOURCE COMMITMENTS

NRC

The environmental report shall discuss any "...irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented…" 10 CFR 51.45(b)(5) as adopted by 10 CFR 51.53(c)(2)

Continued operation of TMI-1 for the license renewal term will result in irreversible and irretrievable resource commitments, including the following:

- Nuclear fuel, which is used in the reactor and is converted to radioactive waste;
- Land required to permanently store or dispose of spent nuclear fuel, low-level radioactive wastes generated as a result of plant operations, and nonradioactive industrial wastes;
- Materials used for construction of the steam generator storage building;
- Elemental materials that will become radioactive; and
- Materials used for the normal industrial operations of the plant that cannot be recovered or recycled or that are consumed or reduced to unrecoverable forms.

6.5 SHORT-TERM USE VERSUS LONG-TERM PRODUCTIVITY OF THE ENVIRONMENT

NRC

The environmental report shall discuss the "...relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity..." 10 CFR 51.45(b)(4) as adopted by 10 CFR 51.53(c)(2)

The current balance between short-term use and long-term productivity at the TMI-1 site was established with the decision to convert approximately 440 acres of farmland and woodland to industrial use. The Final Environmental Statement related to construction and operation evaluated the impacts of constructing and operating TMI-1 (AEC 1972). Natural resources that would be subjected to short-term use include land and water. Three Mile Island and the area surrounding it are largely undeveloped. Approximately 200 acres of the 370-acre island are devoted to the production of electrical energy. This includes the area occupied by TMI-1 facilities (buildings, parking lots, roadways) and landscaped areas around the facilities. Transmission line construction required about 130 acres of land that resulted in the alteration of natural wildlife habitats.

Although TMI-1 consumes water from the Susquehanna River, the impacts are minor and would cease once the reactors cease operation.

Refurbishment would result in the consumption of additional water during hydro-demolition, but the consumption would be limited in duration and would cease once the steam generators are replaced. Air emissions associated with refurbishment would add small amounts of radiological and nonradiological constituents to the air. Likewise, noise impacts would localized and of short duration. The productivity of the aquatic community in the Susquehanna River in the vicinity of TMI-1 is minimally impacted by the water use.

After decommissioning, most environmental disturbances would cease and restoration of the natural habitat could occur. Thus, the "trade-off" between the production of electricity and changes in the local environment is reversible to some extent.

Experience with other experimental, developmental, and commercial nuclear plants has demonstrated the feasibility of decommissioning and dismantling such plants sufficiently to restore a site to its former use. The degree of dismantlement will take into account the intended new use of the site and a balance among health and safety considerations, salvage values, and environmental impact. However, decisions on the ultimate disposition of these lands have not yet been made. Continued operation for an additional 20 years would not increase the short-term productivity impacts described here.

Table 6.1-1. Environmental Impacts Related to License Renewal at TMI-1

No.	Category 2 Issue	Environmental Impact
Surface Water Quality, Hydrology, and Use (for all plants)		
13	Water use conflicts (plants with cooling ponds or cooling towers using makeup water from a small river with low flow)	**SMALL.** TMI-1 consumptive maximum water use is less than 0.1 percent of average river flow. AmerGen complies with the Susquehanna River Basin Commission's Standards for Surface Water Withdrawals in 18 CFR 803.44.
Aquatic Ecology (for plants with once-through or cooling pond heat dissipation systems)		
25	Entrainment of fish and shellfish in early life stages	**NONE.** This issue does not apply because TMI-1 does not use a once-through or cooling pond heat dissipation system.
26	Impingement of fish and shellfish	**NONE.** This issue does not apply because TMI-1 does not use a once-through or cooling pond heat dissipation system.
27	Heat shock	**NONE.** This issue does not apply because TMI-1 does not use a once-through or cooling pond heat dissipation system.
Groundwater Use and Quality		
33	Groundwater use conflicts (potable and service water, and dewatering; plants that use > 100 gpm)	**SMALL.** Based on the requirements of the Susquehanna River Basin Commission permit and results of the pumping tests, negligible impacts are expected to nearby groundwater users.
34	Groundwater use conflicts (plants using cooling towers or cooling ponds and withdrawing makeup water from a small river)	**SMALL.** TMI-1 withdraws from the Susquehanna River at a rate of approximately 1.6 percent of the lowest daily mean. Impacts to the alluvial aquifer are minuscule.
35	Groundwater use conflicts (Ranney wells)	**NONE.** This issue does not apply because TMI-1 does not use Ranney wells.
39	Groundwater quality degradation (cooling ponds at inland sites)	**NONE.** This issue does not apply because TMI-1 does not use cooling ponds.
Terrestrial Resources		
40	Refurbishment impacts	**SMALL.** Impacts are expected to be minimal because the steam generator replacement work will be conducted within the existing industrial footprint of the station, which has been previously disturbed. While peregrine falcons nest at TMI-1, they appear to have become accustomed to the activities at the plant. If it is determined that activities associated with the steam generator replacement project warrant obtaining a permit from the PA Game Commission and/or the U.S. Fish and Wildlife service, an application will be filed at the appropriate time.
Threatened or Endangered Species		
49	Threatened or endangered species	**SMALL.** Bald eagles are common on the Susquehanna River during some seasons of the year. Peregrine falcons and osprey are known to occur at TMI-1. The transmission lines cross counties that have known populations of protected species, but none has been identified in the transmission corridors.

Table 6.1-1. Environmental Impacts Related to License Renewal at TMI-1 (continued)

No.	Category 2 Issue	Environmental Impact
Air Quality		
50	Air quality during refurbishment (non-attainment and maintenance areas)	**SMALL.** Impacts are expected to be minimal because Best Management Practices would be employed during refurbishment activities.
Human Health		
57	Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	**SMALL.** The low temperatures in the Susquehanna River and the disinfection at the sewage treatment facility do not support the propagation of pathological microbes.
59	Electromagnetic fields, acute effects (electric shock)	**SMALL.** The largest modeled induced current under the TMI-1 lines is substantially less than the 5-milliampere limit. Therefore, the TMI-1 transmission lines conform to the National Electrical Safety Code provisions for preventing electric shock from induced current.
Socioeconomics		
63	Housing impacts	**SMALL.** The conceptual addition of 60 jobs would not noticeably affect a housing market of more than one million housing units. Due to the short duration of refurbishment activity, no impacts are expected.
65	Public water supply: public utilities	**SMALL.** Water suppliers in Dauphin and Lancaster Counties have excess capacity. The addition of as many as 60 jobs would not adversely affect the available water supply. Due to the short duration of refurbishment activity, no impacts are expected.
66	Public services: education (refurbishment)	**SMALL.** Due to the short duration of refurbishment activity, no impacts are expected.
68	Offsite land use (refurbishment)	**SMALL.** Due to the short duration of refurbishment activity, no impacts are expected.
69	Offsite land use (license renewal term)	**SMALL.** No plant-induced changes to offsite land use are expected from license renewal because TMI-1 taxes represent less than 3 percent of total tax revenue for the school district and Dauphin County.
70	Public services: transportation	**SMALL.** The addition of as many as 60 employees would not noticeably increase traffic or adversely affect level of service in the vicinity of TMI-1. Due to the short duration of refurbishment activity, no impacts are expected.
71	Historic and archaeological resources	**SMALL.** Continued operation of TMI-1 would require limited construction at the site, primarily for steam generator storage. Construction would occur in a previously disturbed area and therefore, license renewal would have little or no effect on historic or archaeological resources and impacts are expected to be minimal.
Postulated Accidents		
76	Severe accidents	**SMALL.** AmerGen did not identify any cost-effective SAMAs related to aging management.

6.6 REFERENCES

AEC (Atomic Energy Commission). 1972. Final Environmental Statement Related to the Operation of Three Mile Island Nuclear Station Units 1 and 2, Metropolitan Edison Company. Docket Nos. 50-289 and 50-320. December.

Chapter 7

Alternatives to the Proposed Action

NRC

The environmental report shall discuss "Alternatives to the proposed action.…" 10 CFR 51.45(b)(3), as adopted by reference at 10 CFR 51.53(c)(2).

"...The report is not required to include discussion of need for power or economic costs and benefits of ... alternatives to the proposed action except insofar as such costs and benefits are either essential for a determination regarding the inclusion of an alternative in the range of alternatives considered or relevant to mitigation...." 10 CFR 51.53(c)(2).

"While many methods are available for generating electricity, and a huge number of combinations or mixes can be assimilated to meet a defined generating requirement, such expansive consideration would be too unwieldy to perform given the purposes of this analysis. Therefore, NRC has determined that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation sources that are technically feasible and commercially viable…" (NRC 1996a).

"…The consideration of alternative energy sources in individual license renewal reviews will consider those alternatives that are reasonable for the region, including power purchases from outside the applicant's service area...." (NRC 1996b)

Chapter 7 evaluates alternatives to Three Mile Island Nuclear Station Unit 1 (TMI-1) license renewal. The chapter identifies actions that AmerGen Energy Company, LLC (AmerGen) might take, and associated environmental impacts, if the U.S. Nuclear Regulatory Commission (NRC) does not renew the plant's operating license. The chapter also addresses actions that AmerGen has considered, but would not take, and discusses the bases for determining that such actions would be unreasonable.

The alternatives discussed in this chapter are divided into two categories, "no-action" and "alternatives that meet system generating needs." In considering the level of detail and analysis that it should provide for each category, AmerGen relied on the NRC decision-making standard for license renewal:

> "…the NRC staff, adjudicatory officers, and Commission shall determine whether or not the adverse environmental impacts of license renewal are so great that preserving the option of license renewal for energy planning decision makers would be unreasonable." [10 Code of Federal Regulations (CFR) 51.95(c)(4)].

AmerGen has determined that the environmental report would support NRC decision making as long as the document provides sufficient information to clearly indicate whether an alternative would have a smaller, comparable, or greater environmental impact than the proposed action. Providing additional detail or analysis serves no function if it only brings to light additional adverse impacts of alternatives to license renewal. This approach is consistent with regulations of the Council on Environmental Quality, which provide that the consideration of alternatives (including the proposed action) should enable reviewers to evaluate their comparative merits (40 CFR 1500-1508). AmerGen believes that Chapter 7 provides sufficient detail about alternatives to establish the basis for necessary comparisons to the Chapter 4 discussion of impacts from the proposed action.

In characterizing environmental impacts from alternatives, the same definitions of "small," "moderate," and "large" presented in the introduction to Chapter 4 are used in this chapter.

7.1 NO-ACTION ALTERNATIVE

The “no-action alternative” refers to a scenario in which NRC does not renew the TMI-1 operating license. Components of this alternative include replacing the generating capacity of TMI-1 and decommissioning the facility, as described below.

TMI-1 provides approximately 7 terawatt-hours of electricity annually (EIA 2006a) with 802 megawatts of base-load electrical capacity (AmerGen 2005) to residents and other consumers in the mid-Atlantic region. Replacement could be accomplished by (1) building new generating base-load capacity, (2) purchasing power from the wholesale market, or (3) reducing power requirements through demand reduction. Section 7.2.1 describes each of these possibilities in detail, and Section 7.2.2 describes environmental impacts from feasible alternatives.

The Generic Environmental Impact Statement (GEIS) (NRC 1996a, pg. 7-1) defines decommissioning as the safe removal of a nuclear facility from service and the reduction of residual radioactivity to a level that permits release of the property for unrestricted use and termination of the license. One of the NRC-evaluated decommissioning options is immediate decontamination and dismantlement, and safe storage of the stabilized and defueled facility for a period of time, followed by additional decontamination and dismantlement. Regardless of the option chosen, decommissioning must be completed within a 60-year period. Under the no-action alternative, AmerGen would continue operating TMI-1 until the existing license expires, then initiate decommissioning activities in accordance with NRC requirements. The GEIS describes decommissioning activities based on an evaluation of a larger reactor (the “reference” pressurized-water reactor is the 1,175-megawatt-electric [MWe] Trojan Nuclear Plant). This description is applicable to decommissioning activities that AmerGen would conduct at TMI-1.

As the GEIS notes, NRC has evaluated environmental impacts from decommissioning. NRC-evaluated impacts include impacts of occupational and public radiation dose; impacts of waste management; impacts to air and water quality; and ecological, economic, and socioeconomic impacts. NRC indicated in the Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities; Supplement 1 (NRC 2002a, Section 4.3.8) that the environmental effects of greatest concern (i.e., radiation dose and releases to the environment) are substantially less than the same effects resulting from reactor operations. AmerGen adopts by reference the NRC conclusions regarding environmental impacts of decommissioning.

AmerGen notes that decommissioning activities and their impacts are not discriminators between the proposed action and the no-action alternative. TMI-1 will have to be decommissioned regardless of the NRC decision on license renewal; license renewal would only postpone decommissioning for another 20 years. NRC has established in the GEIS that the timing of decommissioning operations does not substantially influence the environmental impacts of decommissioning. AmerGen adopts by reference the NRC findings (10 CFR 51, Appendix B, Table B 1, Decommissioning) to the effect that delaying decommissioning until after the renewal term would have small environmental impacts. The discriminators between the proposed action and the no-action alternative lie within the choice of generation replacement options to be part of the no-action alternative. Section 7.2.2 analyzes the impacts from these options.

AmerGen concludes that the decommissioning impacts under the no-action alternative would not be substantially different from those occurring following license renewal, as identified in the GEIS (NRC 1996a) and in the decommissioning generic environmental impact statement (NRC 2002a). These impacts would be temporary and would occur at the same time as the impacts from meeting system generating needs.

7.2 ALTERNATIVES THAT MEET SYSTEM GENERATING NEEDS

TMI-1 has a maximum net capacity of 802 MWe (AmerGen 2005) and generated approximately 7.3 terawatt-hours of electricity in 2004 and 6.8 terawatt-hours in 2005 (EIA 2006a). This power is sufficient to supply the electricity used by over 300,000 homes (Exelon 2006), and would be unavailable to customers in the event the TMI-1 operating license is not renewed.

The power consumed in Pennsylvania is not limited to electricity generated within the Commonwealth. Pennsylvania relies on electricity drawn from the PJM Interconnection, a regional network that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. One consequence of the network is that electric power consumers in Pennsylvania are not specifically dependent on electricity generated within the Commonwealth. The current mix of power generation options within the PJM region is one indicator of what AmerGen considers to be feasible alternatives. In 2005, electric generators connected to the PJM network had a total generating capacity of 164,634 MWe (PJM 2006a). This capacity includes units fueled by coal (41.5 percent), nuclear (19.1 percent), oil (7.2 percent), natural gas (27.5 percent), hydroelectric (4.5 percent), and renewable sources (0.3 percent) (PJM 2006b). In 2005, the electric industry in the PJM region provided 728 terawatt-hours of electricity (PJM 2006a). Power generation in the PJM region was dominated by coal (66.6 percent), followed by nuclear (25.2 percent), natural gas (5.6 percent), hydroelectric (1.3 percent), oil (0.9 percent) and renewable sources (0.5 percent) (PJM 2006b). Figures 7.2-1 and 7.2-2 illustrate the electric industry generating capacity and energy output by fuel type for the PJM region.

Comparison of generating capacity with actual utilization of this capacity indicates that coal and nuclear are used by PJM substantially more relative to their PJM capacity than either oil-fired or gas-fired generation. This condition reflects the relatively low fuel cost and base-load suitability for nuclear power and coal-fired plants, and relatively higher use of gas- and oil-fired units to meet peak loads. Comparison of capability and energy production for petroleum and gas-fired facilities indicates a strong preference for gas firing over oil firing, indicative of the higher cost and greater air emissions associated with oil firing. Energy production from hydroelectric sources is similarly preferred from a cost standpoint, but capacity is limited and utilization can vary substantially depending on water availability.

7.2.1 ALTERNATIVES CONSIDERED

Technology Choices

For the purposes of this environmental report, alternative generating technologies were evaluated to identify candidate technologies that would be capable of replacing TMI-1's base-load capacity of 802 MWe.

Based on these evaluations, it was determined that new plant systems capable of replacing the capacity of the TMI-1 nuclear unit are limited to pulverized-coal and gas-fired combined-cycle units for base-load operation. This conclusion is borne out by the generation information presented above that identifies coal as the most heavily used non-nuclear generating fuel type in the region. AmerGen would use natural gas as the primary fuel in its combined-cycle turbines because of the economic and environmental advantages of gas over oil. Manufacturers now have large standard sizes of combined-cycle gas turbines that are economically attractive and suitable for high-capacity base-load operation. For the purposes of the TMI-1 license renewal environmental report, AmerGen has limited its analysis of new generating capacity alternatives to the technologies it considers feasible: pulverized coal- and gas-fired units. AmerGen chose to evaluate combined-cycle turbines in lieu of simple-cycle turbines because the combined-cycle option is more economical. The benefits of lower operating costs for the combined-cycle option outweigh its higher capital costs.

Effects of Restructuring

Nationally, the electric power industry has been undergoing a transition from a regulated industry to a competitive market environment. Efforts to deregulate the electric utility industry began with passage of the National Energy Policy Act of 1992. Provisions of this act required electric utilities to allow open access to their transmission lines and encouraged development of a competitive wholesale market for electricity. The Act did not mandate competition in the retail market, leaving that decision to the states (NEI 2000). Over the past few years, states within the PJM region have transitioned to competitive wholesale and retail markets.

In 1996, Pennsylvania enacted the “Electricity Generation Customer Choice and Competition Act.” Provisions of the Act opened Pennsylvania’s retail electric power market to competition. The Pennsylvania Public Utility Commission (PPUC) provides strategic direction and policy guidance for oversight of the electric power industry in the Commonwealth, including the restructuring initiative (Pennsylvania General Assembly 1996).

In 2004, Pennsylvania adopted the Alternative Energy Portfolio Standards Act (AEPS), which requires all suppliers selling retail electricity in Pennsylvania (retail electric suppliers) to include alternative energy sources in the mix of energy that they sell. Eligible resources may be located anywhere within the PJM region (Pennsylvania General Assembly 2004).

The AEPS established two tiers of alternative energy sources and set minimum requirements for each tier. By 2007 at least 1.5 percent of the electricity sold by a retail electric supplier must come from Tier I sources. Tier I sources include wind, solar photovoltaic energy, low-impact hydropower, geothermal sources, biologically-derived methane gas, fuel cells, biomass, and coal mine methane. The Tier I percentage increases by 0.5 percent each year, and by the year 2020, at least 8 percent of the retail electric energy sold in Pennsylvania must be generated from Tier I sources. The AEPS also requires that a very small percentage of Tier I generation be from solar photovoltaic technologies.

In addition, a certain percentage of electricity sold by retail electric suppliers must be generated from Tier II alternative energy sources. Tier II sources include energy derived from waste coal, distributed generation systems, demand side management (DSM), large-scale hydropower, municipal solid waste generation, utilizing the byproducts of pulping or wood-manufacturing processes, and integrated combined coal gasification technology. The AEPS requires 4.2 percent of energy sold each year through 2009 to be generated using Tier II resources. The percentage increases incrementally until the year 2020 when at least 10 percent of the retail electric energy sold in Pennsylvania must be supplied from Tier II sources.

As mentioned above, the AEPS includes provisions for DSM measures to reduce electricity demand within the Commonwealth. Eligible measures include energy efficiency measures undertaken by residential, commercial, institutional, or governmental customers; load management and demand response approaches that shift electric load from periods of higher to lower demand; and the reuse of energy from exhaust gases or other manufacturing by-products or useful thermal energy for electricity production by industrial and manufacturing customers. These measures also enable electricity customers to benefit from the energy credit market created by the portfolio standard. Retail customers who reduce their electricity demand through energy efficiency and load management, or who generate electricity by reusing energy, will earn alternative energy credits that they can sell to utility companies (Pennsylvania General Assembly 2004).

Alternatives

The following sections present fossil-fuel-fired generation (Section 7.2.1.1) and purchased power (Section 7.2.1.2) as reasonable alternatives to license renewal. Section 7.2.1.3 discusses reduced demand and presents the basis for concluding that it is not a reasonable alternative to license renewal. Section 7.2.1.4 discusses other alternatives that AmerGen has determined are not reasonable and the bases for these determinations.

7.2.1.1 Construct and Operate Fossil-Fuel-Fired Generation

Construction of a hypothetical new power station at the present TMI-1 site or another existing power station would be preferable to construction at a new green field site. This approach would minimize environmental impacts by building on previously disturbed land and by making the most use possible of existing facilities, such as transmission lines, roads and parking areas, office buildings, and components of the cooling system. However, there is insufficient area at the existing TMI-1 site to construct a new coal- or gas-fired unit, thus a new plant would have to be located elsewhere. AmerGen's parent company, Exelon, owns or co-owns numerous fossil power plants in the mid-Atlantic region and would look to site a replacement for TMI-1 at an existing fossil plant site in this region, however, this may not be feasible. As mentioned above, locating the new plant at an existing plant site would benefit from the existing infrastructure and minimize the environmental impact which would occur at a new green field location. Consequently, to avoid overstating the impacts associated with new coal- and gas-fired unit construction scenarios, AmerGen has elected to assume that any hypothetical new power station would be constructed at an existing fossil plant site.

To compare gas- and coal-fired units on an equal basis, AmerGen set the net electrical generating capacities of the alternative hypothetical gas- and coal-fired units at the same values. For comparability, the net power of the coal-fired unit was set equal to that of the gas-fired plant (793 MWe). Although this provides less capacity than the existing unit, it ensures against overestimating environmental impacts from the alternatives.

It must be emphasized, however, that these are hypothetical scenarios. AmerGen does not have plans to construct one of these units.

Gas-Fired Generation

For purposes of this analysis, AmerGen assumed development of a modern natural gas-fired combined-cycle plant with design characteristics similar to those being developed elsewhere in the PJM region, and with a generating capacity similar to TMI-1. The hypothetical plant would be composed of two pre-engineered natural gas-fired systems producing 263 MWe and 530 MWe of net plant power for a total of 793 MWe (Chase and Kehoe 2000). The characteristics of this plant and other relevant resources were used to define the gas-fired alternative. Table 7.2-1 presents the basic characteristics for the gas-fired alternative.

Coal-Fired Generation

NRC has routinely evaluated coal-fired generation alternatives for nuclear plant license renewal. In defining the coal-fired alternative to TMI-1, site- and Pennsylvania-specific input has been applied for direct comparison with a gas-fired plant producing 793 MWe.

Table 7.2-2 presents the basic coal-fired alternative emission control characteristics. The emissions control assumptions are based on the technologies recognized by Environmental Protection Agency (EPA) for minimizing emissions and calculated emissions based upon the EPA published removal efficiencies (EPA 1998a). AmerGen assumes that the representative plant would be located at an unidentified green field site, which will require new infrastructure (e.g., rail spur, cooling water system, transmission, roads, and technical and administrative support facilities).

7.2.1.2 Purchased Power

AmerGen has evaluated conventional and prospective power supply options that could be reasonably implemented before the existing TMI-1 license expires. As noted in Section 7.2.1, electric industry restructuring initiatives in the Commonwealth of Pennsylvania and other states in the PJM region are designed to promote competition in energy supply markets by facilitating participation by non-utility suppliers. PJM has implemented market rules to appropriately anticipate and meet electricity demands in the resulting wholesale electricity market. As an additional facet of this restructuring effort, retail customers in the region now may choose among any company with electric generation to supply their power, resulting in uncertainty with regard to future AmerGen load obligations. In view of these conditions, AmerGen assumes for purposes of this analysis that adequate supplies of electricity would be available, and that purchased power would be a reasonable alternative to meet the Station's load requirements in the event the existing operating license for TMI-1 is not renewed.

The source of this purchased power may reasonably include new generating facilities developed elsewhere in the Commonwealth or neighboring states in the PJM region. The technologies that would be used to generate this purchased power are similarly speculative. AmerGen assumes that the generating technology used to produce purchased power would be one of those that NRC analyzed in the GEIS. For this reason, AmerGen is adopting by reference the GEIS description of the alternative generating technologies as representative of the purchase power alternative. Of these technologies, facilities fueled by coal and combined-cycle facilities fueled by natural gas are the most cost effective for providing base-load capacity.

AmerGen anticipates that additional transmission infrastructure would be needed in the event purchased power must replace TMI-1 capacity. From a local perspective, loss of TMI-1 could require construction of new transmission lines to ensure local system stability. From a regional perspective, PJM's inter-connected transmission system is highly reliable, and the market-driven process for adding capacity in the region is expected to have a positive impact on overall system reliability.

7.2.1.3 Demand Side Management

As discussed in Section 7.2.1, Pennsylvania has adopted Alternative Energy Portfolio Standards that include provisions for market–based DSM measures to reduce electricity demand within the Commonwealth.

Prior to adopting the AEPS, Pennsylvania had developed a comprehensive program to promote and advance DSM in the retail electric market through individual settlements with the Commonwealth's major distribution companies. The Pennsylvania Sustainable Energy Board worked in partnership with regional sustainable energy boards, other commonwealth agencies, electric utilities, business organizations and environmental organizations to develop and implement "tools" to save energy. Pennsylvania's DSM offerings under this program included from load curtailment incentives during periods of peak demand to rebates; financial incentives for commercial, industrial, and residential customers for installation of energy-efficient appliances and equipment; and educational programs and demonstration projects (PSEB 2004).

Since 1997, Pennsylvania's DSM programs have saved Pennsylvania residents and businesses over 56 terawatt-hours in avoided electricity use, and additional demand reductions are projected to result from these efforts (Pinero 2001). However, it is expected that projected energy efficiencies would be anticipated by the market. As a practical matter, it would be impossible to increase those energy savings by an additional 802 MWe to replace the TMI-1 generating capability. For these reasons, AmerGen does not consider energy conservation to represent a reasonable alternative to renewal of the TMI-1 operating licenses.

7.2.1.4 Other Alternatives

This section identifies alternatives that AmerGen has determined are not reasonable for replacing TMI-1 and the bases for these determinations. AmerGen accounted for the fact that TMI-1 is a base-load generator and that any feasible alternative to TMI-1 would also need to be able to generate base-load power. For purposes of analysis, AmerGen assumed that the states of Pennsylvania, New Jersey and Maryland comprise the PJM region. In performing this evaluation, AmerGen relied heavily upon NRC's GEIS (NRC 1996a).

Wind

Wind power, due to its intermittent nature, is not suitable for base-load generation. As discussed in Section 8.3.1 of the GEIS, wind power systems produce power only when the wind is blowing at a sufficient velocity and duration (McGowan and Connors 2000). While recent advances in technology have improved wind turbine capacity, average annual capacity factors for wind power systems are relatively low (25 to 40 percent) (McGowan and Connors 2000) compared to 90 to 95 percent industry average for a base-load plant such as a nuclear plant.

The energy potential in the wind is expressed by wind generation classes ranging from 1 (least energetic) to 7 (most energetic). Current wind technology can operate economically on Class 4 sites with the support of the Federal production tax credit of 1.9 cent per kWh (DOE 2006), while Class 3 wind regimes will require further technical development for utility-scale application. In the PJM region, the primary areas of good wind energy resource are the Atlantic coast, the Great Lakes, and exposed hilltops, ridge crests, and mountain summits in Pennsylvania. Areas of highest wind energy potential (Class 5 and 6) are the outer coastal areas of New Jersey, offshore areas of Lake Erie, and the higher mountain summits of the Appalachians. Offshore wind resources are abundant (NJDEP 2005) but offshore technology is not sufficiently mature (DOE 2006) for present consideration.

Based on American Wind Energy Association estimates (AWEA 2006), the PJM region has the technical potential (the upper limit of renewable electricity production and capacity that could be brought online, without regard to cost, market acceptability, or market constraints) for roughly 6,658 MWe of installed wind power capacity. The full exploitation of wind energy is constrained by a variety of factors including land availability and land-use patterns, surface topography, infrastructure constraints, environmental constraints, wind turbine capacity factor, wind turbine availability, and grid availability. By mid-2006, a total of 171 MWe of wind energy had been developed in PJM region. Projected new capacity in various stages of planning or permit review within the PJM region includes an additional 391 MWe of wind energy (AWEA 2006).

Wind farms generally consist of 10-50 turbines in the 1-3 MWe range. Estimates based on existing installations indicate that a utility-scale wind farm would be spread over 30 to 50 acres per MWe of installed capacity (McGowan & Connors 2000). However, the actual area occupied by turbines, substations, and access roads may occupy only 3 to 5 percent of the wind farm's total acreage, thus the remaining area is available for other uses. When the wind farm is located on land already used for intensive agriculture the additional impact to wildlife and habitat will likely be minor, while disturbance caused by wind farms in more remote areas may be more significant. Therefore, replacement of TMI-1 generating capacity (802 MWe net) with wind power, assuming a capacity factor of 35 percent, would require a large green field site about 180 square miles of which 5 to 9 square miles would be disturbed and unavailable for other uses. The State of New Jersey promotes wind power as a component of its Renewable Portfolio Standard, but concludes that wind, due to its intermittent nature, is unsuitable to provide base-load power (NJDEP 2005). Similarly, AmerGen has concluded that wind power is not a reasonable alternative to TMI-1 license renewal.

<u>Solar</u>

By its nature, solar power is intermittent. In conjunction with energy storage mechanisms, solar power might serve as a means of providing base-load power. However, current energy storage technologies are too expensive to permit solar power to serve as a large base-load generator. Even without consideration of storage capacity, solar power technologies (photovoltaic and thermal) cannot currently compete with conventional fossil-fueled technologies in grid-connected applications due to high costs per kilowatt of capacity (EERE 2006a).

Solar power is not a technically feasible alternative for base-load capacity in the PJM region. The PJM region receives 3.5 to 5.5 kilowatt hours of solar radiation per square meter per day compared with 4.5 to 7.5 kilowatt hours per square meter per day in areas of the West, such as California, which are most promising for solar technologies (NREL 2004).

Finally, land requirements for solar plants are high. Estimates based on existing installations indicate that utility-scale plants would occupy about 3.8 acres per MWe for photovoltaic and 8 acres per MWe for solar thermal systems (DOE 2004). Utility-scale solar plants have only been used in regions such as the western U.S. that receive high concentrations (5 to 7.2 kilowatt hours per square meter per day) of solar radiation. AmerGen believes that a utility-scale solar plant located in the PJM region, which receives 2.8 to 3.9 kilowatt hours of solar radiation per square meter per day, would occupy about 16 acres per MWe for photovoltaic and 25 acres per MWe for solar thermal systems. Therefore, replacement of TMI-1 generating capacity with solar power would require dedication of about 20 square miles for photovoltaic and 31 square miles for solar thermal systems, and both would have large environmental impacts at a green field site.

AmerGen has concluded that, due to the high cost, limited availability of sufficient incident solar radiation, and the amount of land needed (approximately 20 to 31 square miles), solar power is not a reasonable alternative to TMI-1 license renewal.

Hydropower

About 7,440 MWe of utility generating capacity in the PJM region is hydroelectric (PJM 2006c). As the GEIS points out in Section 8.3.4, hydropower's percentage of United States generating capacity is expected to decline because hydroelectric facilities have become difficult to site as a result of public concern over flooding, destruction of natural habitat, and alteration of natural river courses. A small number of hydropower projects, the largest of which is 2.15 MWe, are being considered in the PJM region (FERC 2006). These small hydropower projects could not replace the 802 MWe generated at TMI-1. According to the U.S. Hydropower Resource Assessment (INEEL 1998), there are no remaining sites in the PJM region that would be environmentally suitable for a large hydroelectric facility.

The GEIS estimates land use of 1,600 square miles per 1,000 MWe for hydroelectric power. Based on this estimate, replacement of TMI-1 generating capacity would require flooding approximately 1,270 square miles, resulting in a large impact on land use. Further, operation of a hydroelectric facility would alter aquatic habitats above and below the dam, which would impact existing aquatic communities.

AmerGen has concluded that, due to the lack of suitable sites in the PJM region for a large hydroelectric facility and the amount of land needed (approximately 1,270 square miles), hydropower is not a reasonable alternative to TMI-1 license renewal.

Geothermal

Geothermal energy is a proven resource for power generation. Geothermal power plants use naturally heated fluids as an energy source for electricity production. To produce electric power, underground high-temperature reservoirs of steam or hot water are tapped by wells and the steam rotates turbines that generate electricity. Typically, water is then returned to the ground to recharge the reservoir (NREL 1997).

Geothermal energy can achieve average capacity factors of 95 percent and can be used for base-load power where this type of energy source is available (NREL 1997). Widespread application of geothermal energy is constrained by the geographic availability of the resource. In the U.S., high-temperature hydrothermal reservoirs are located in the western continental U.S., Alaska, and Hawaii. There are no known high-temperature geothermal sites in Pennsylvania.

Pennsylvania has low to moderate temperature resources that can be tapped for direct heat or geothermal heat pumps, but electricity generation is not feasible with these resources (EERE 2006b).

Wood Energy

As discussed in the GEIS (NRC 1996a), the use of wood waste to generate electricity is largely limited to those states with significant wood resources. The pulp, paper, and paperboard industries in states with adequate wood resources generate electric power by consuming wood and wood waste for energy, benefiting from the use of waste materials that could otherwise represent a disposal problem. According to the U.S. Department of Energy, Pennsylvania is the only state in the PJM region that is considered to have adequate wood resources (Walsh et al. 2000). However, the largest wood waste power plants are 40 to 50 MWe in size.

Further, as discussed in Section 8.3.6 of the GEIS (NRC 1996a), construction of a wood-fired plant would have an environmental impact that would be similar to that for a coal-fired plant, although facilities using wood waste for fuel would be built on smaller scales. Like coal-fired plants, wood-waste plants require large areas for fuel storage, processing, and waste (i.e., ash) disposal. Additionally, operation of wood-fired plants has environmental impacts, including impacts on the aquatic environment and air. Wood has a low heat content that makes it unattractive for base-load applications. It is also difficult to handle and has high transportation costs.

While some wood resources are available in the PJM region, AmerGen has concluded that, due to the lack of an environmental advantage, low heat content, handling difficulties, and high transportation costs, wood energy is not a reasonable alternative to TMI-1 license renewal.

Municipal Solid Waste

As discussed in Section 8.3.7 of the GEIS (NRC 1996a), the initial capital costs for municipal solid waste plants are greater than for comparable steam turbine technology at wood-waste facilities. This is due to the need for specialized waste separation and handling equipment.

The decision to burn municipal solid waste to generate energy is usually driven by the need for an alternative to landfills, rather than by energy considerations. The use of landfills as a waste disposal option is likely to increase in the near term; however, it is unlikely that many landfills will begin converting waste to energy because of unfavorable economics.

Estimates in the GEIS suggest that the overall level of construction impacts from a waste-fired plant should be approximately the same as that for a coal-fired plant. Additionally, waste-fired plants have the same or greater operational impacts (including impacts on the aquatic environment, air, and waste disposal). Some of these impacts would be moderate, but still larger than the environmental effects of TMI-1 license renewal.

AmerGen has concluded that, due to the high costs and lack of environmental advantages, burning municipal solid waste to generate electricity is not a reasonable alternative to TMI-1 license renewal.

Other Biomass-Derived Fuels

In addition to wood and municipal solid waste fuels, there are several other concepts for fueling electric generators, including burning energy crops, converting crops to a liquid fuel such as ethanol (ethanol is primarily used as a gasoline additive), and gasifying energy crops (including wood waste). As discussed in the GEIS, none of these technologies has progressed to the point of being competitive on a large scale or of being reliable enough to replace a base-load plant such as TMI-1.

Further, estimates in the GEIS suggest that the overall level of construction impacts from a crop-fired plant should be approximately the same as that for a wood-fired plant. Additionally, crop-fired plants would have similar operational impacts (including impacts on the aquatic environment and air). These systems also have large impacts on land use, due to the acreage needed to grow the energy crops.

AmerGen has concluded that, due to the high costs and lack of environmental advantage, burning other biomass-derived fuels is not a reasonable alternative to TMI-1 license renewal.

Petroleum

The PJM region has several petroleum (oil)-fired power plants; however, they produce less than 1 percent of the total power generated in the region (PJM 2006c). From 1990 to 2004, utilities in the PJM region reduced the proportion of power produced by oil-fired generating plants by 34 percent (EIA 2006c). Oil-fired operation is more expensive than nuclear or coal-fired operation, and future increases in petroleum prices are expected to make oil-fired generation increasingly more expensive than coal-fired generation.

Also, construction and operation of an oil-fired plant would have environmental impacts. For example, Section 8.3.11 of the GEIS (NRC 1996a) estimates that construction of a 1,000-MWe oil-fired plant would require about 120 acres. Additionally, operation of oil-fired plants would have environmental impacts (including impacts on the aquatic environment and air) that would be similar to those from a coal-fired plant.

AmerGen has concluded that, due to the high costs and lack of obvious environmental advantage, oil-fired generation is not a reasonable alternative to TMI-1 license renewal.

Fuel Cells

Fuel cell power plants are in the initial stages of commercialization. While more than 650 large stationary fuel cell systems have been built and operated worldwide, the global stationary fuel cell electricity generating capacity in 2003 was only 125 MWe. In addition, the largest stationary fuel cell power plant is only 11 MWe (Fuel Cell Today 2003). Recent estimates suggest that a company would have to produce about 100 MWe of fuel cell stacks annually to achieve a price of $1,000 to $1,500 per kilowatt (Kenergy 2000). However, the production capability of the largest stationary fuel cell manufacturer is 50 MWe per year (CSFCC 2002). AmerGen believes that this technology has not matured sufficiently to support production for a facility the size of TMI-1, and AmerGen has concluded that, due to cost and production limitations, fuel cell technology is not a reasonable alternative to TMI-1 license renewal.

Advanced Nuclear Reactor

Increased interest in the development of advanced nuclear power plants has been expressed recently by members of both industry and government. However, AmerGen considers it unlikely that a replacement for TMI-1 could be sited, planned, licensed, constructed, and brought online by the time the existing operating license expires in 2014.

Delayed Retirement

As the NRC noted in the GEIS (NRC 1996a, Section 8.3.13), extending the lives of existing non-nuclear generating plants beyond the time they were originally scheduled to be retired represents another potential alternative to license renewal. AmerGen does not own any non-nuclear power plants and AmerGen's parent company, Exelon, has no plans to retire any of its base-load fossil units in the PJM region (PJM 2006c). Thus delayed retirement of the above generation sources could not replace the 802 MWe generated at TMI-1.

New generation capacity within the PJM will likely not be available to replace TMI-1's capacity. Power generating utilities within the PJM have retired a large number of generation retirements totaling 5,700 MWe over the last two years and this has resulted in multiple reliability criteria violations. The problem has been magnified by steady load growth and sluggish generation additions (PJM 2006b). Some potential reliability issues have been forestalled through a combination of short lead-time transmission upgrades, voluntary deactivation deferrals, and implementation of a process that compensates generators that remain online beyond announced retirement dates. However, the Federal Energy Regulatory Commission recently determined that PJM cannot compel the owners of units scheduled for retirement to remain in service. For these reasons, the delayed retirement of non-nuclear generating units is not considered a reasonable alternative to TMI-1 license renewal (PJM 2006b).

Combination of Alternatives

NRC indicated in the GEIS that, while many methods are available for generating electricity and a huge number of combinations or mixes can be assimilated to meet system needs, such expansive consideration would be too unwieldy, given the purposes of the alternatives analysis. Therefore, NRC determined that a reasonable set of alternatives should be limited to the analysis of single discrete electrical generation sources and only those electric generation technologies that are technically reasonable and commercially viable (NRC 1996a, pg. 8-1). Nevertheless, for the purpose of comparison, AmerGen has assumed that a 100 MWe wind farm, along with a 530 MWe natural gas combined-cycle unit and 272 MWe of power purchased from the wholesale electricity market could replace the TMI-1 generating capacity (802 MWe net). When operating, the combined cycle plant can "follow" the wind load by ramping up and down quickly. When the wind is blowing hard, the combined cycle plant can be ramped down; when the wind is not blowing or is blowing too softly to turn the wind turbines, the combined cycle plant can be ramped up. Power purchased from other generators in the PJM market would provide the balance of electricity needed.

Operation of the new natural gas-fired power plant would result in increased air emissions and other impacts. The impacts associated with the wind portion of the alternative – land use impacts, noise impacts, visual impacts, impacts on wildlife, etc. – would be more than the stand alone natural gas alternative. The environmental impacts associated with power purchased from other generators would be similar to the impacts associated with the coal and gas-fired alternatives, but would be located elsewhere within the PJM region.

AmerGen concludes that it is very unlikely that the environmental impacts of any combination of generating and conservation options would be reduced to the level of impacts associated with renewal of the TMI-1 operating license. Therefore, a combination of alternatives is not considered a reasonable alternative to TMI-1 license renewal.

7.2.2 ENVIRONMENTAL IMPACTS OF ALTERNATIVES

This section evaluates the environmental impacts of alternatives that AmerGen has determined to be reasonable alternatives to TMI-1 license renewal: gas-fired generation, coal-fired generation, and purchased power.

7.2.2.1 Gas-Fired Generation

NRC evaluated environmental impacts from gas-fired generation alternatives in the GEIS, focusing on combined-cycle plants. Section 7.2.1.1 presents AmerGen's reasons for defining the gas-fired generation alternative as a 2-unit combined-cycle plant on an existing fossil plant site. Construction of a gas-fired unit would have impacts on land-use and could impact ecological, aesthetic, and cultural resources. Human health effects associated with air emissions would be of concern. Aquatic biota losses due to cooling water withdrawals would be offset by the concurrent shutdown of the nuclear generator.

Air Quality

Natural gas is a relatively clean-burning fossil fuel that primarily emits nitrogen oxides (NOx), a regulated pollutant, during combustion. A natural gas-fired plant would also emit small quantities of sulfur oxides (SOx), particulate matter, and carbon monoxide (CO), all of which are regulated pollutants. Control technology for gas-fired turbines focuses on NOx emissions. From data published by EPA (EPA 2000), the emissions from the natural gas-fired plant are calculated to be:

SOx = 64 tons per year

NOx = 168 tons per year

Carbon monoxide = 1,123 tons per year

Filterable Particulates = 36 tons per year [all particulates are particulates with diameters less than 2.5 microns ($PM_{2.5}$)]

In 2004, Pennsylvania was ranked 2nd nationally in sulfur dioxide (SO_2) emissions and 5th nationally in NOx emissions from electric power plants (EIA 2006c). The ranking was based on quantity emitted. For example, the electric power plants in only 1 state emitted more SO_2 than those located in Pennsylvania. The acid rain requirements of the Clean Air Act Amendments capped the nation's SO_2 emissions from power plants. Each company with fossil-fuel-fired units was allocated SO_2 allowances. To be in compliance with the Act, the companies must hold enough allowances to cover their annual SO_2 emissions. AmerGen would need to obtain SO_2 credits to operate a fossil-fuel-fired plant. In 1998, the EPA promulgated the NOx SIP (State Implementation Plan) Call regulation that required 22 states, including Pennsylvania, to reduce their NOx emissions by over 30 percent to address regional transport of ground-level ozone across state lines (EPA 1998b). In 2005 EPA issued the Clean Air Interstate Rule (CAIR), which will permanently cap emissions of SO_2 and NOx in 28 eastern states and the District of Columbia using a cap and trade program. The NOx and SO_2 programs commence in 2009 and 2010, respectively. To operate a new fossil-fuel-fired plant, AmerGen would need to obtain enough NOx credits to cover annual emissions either from the set-aside pool or by buying NOx credits from other sources. Additionally, because all of Pennsylvania is treated as a non-attainment area for ozone, a fossil-fuel-fired plant would need to obtain NOx emission reduction credits in the amount of 1.15 tons of NOx for every ton of NOx emitted.

NOx effects on ozone levels, SO_2 allowances, and NOx credits could all be issues of concern for gas-fired combustion. While gas-fired turbine emissions are less than coal-fired boiler emissions, the emissions are still substantial. AmerGen concludes that emissions from the gas-fired alternative would noticeably alter local air quality, but would not cause or contribute to violations of National Ambient Air Quality Standards in the region. Air quality impacts would therefore be MODERATE.

Waste Management

The solid waste generated from this type of facility would be minimal. The only noteworthy waste would be from spent selective catalytic reduction (SCR) used for NOx control. The SCR process for a 793 MWe plant would generate approximately 500 ft^3 of spent catalyst per year (NRC 2002b). AmerGen concludes that gas-fired generation waste management impacts would be SMALL.

Other Impacts

Construction of the gas-fired alternative on an existing plant site would impact the construction site and the supporting utility corridors. A new gas pipeline would likely be required for the gas turbine generators in this alternative. To the extent practicable, AmerGen would route the pipeline along existing, previously disturbed, right-of-way to minimize impacts. A new pipeline of approximately 10-inch diameter would require a 50-foot-wide corridor. This new construction may also necessitate an upgrade of the Statewide pipeline network. AmerGen estimates that 32 acres would be needed for a plant site, resulting in the loss of terrestrial habitat. Aesthetic impacts, erosion and sedimentation, fugitive dust, and construction debris impacts would be noticeable but MODERATE with appropriate controls. AmerGen estimates a peak construction workforce of 483 thus socioeconomic impacts of construction would be SMALL. However, AmerGen estimates a significantly reduced workforce of 27 for gas operations, resulting in adverse socioeconomic impacts due to the loss of 600-800 personnel responsible for operational activities at TMI-1 and the 200 to 1,400 additional personnel employed during TMI-1 refueling outages. Loss of the operational and temporary personnel would impact various aspects of the local community including employment, taxes, housing, offsite land use, economic structure, and public services (NRC 1996a). AmerGen believes these impacts would be MODERATE.

Impacts to aquatic resources and water quality would be similar to, but smaller than, the impacts of TMI-1 due to the replacement plant's use of the cooling water withdrawals from and discharges to the Susquehanna River or other naturally occurring body of water. These impacts would be offset by the concurrent shutdown of TMI-1. The stacks and boilers of the new gas-fired unit may add visual impacts at the existing power plant site where it is constructed, but these should be minimal because of the presence of existing plant structures. Impacts to cultural resources would be possible, but if surveys for archaeological and cultural resources were not already done at the time the existing plant at the selected site was constructed, site surveys would be conducted to identify these resources and mitigate any impacts.

7.2.2.2 Coal-Fired Generation

NRC evaluated environmental impacts from coal-fired generation alternatives in the GEIS (NRC 1996a). NRC concluded that construction impacts could be substantial, due in part to the large land area required (which can result in natural habitat loss) and the large workforce needed. NRC identified major adverse impacts from operations as human health concerns associated with air emissions, waste generation, and losses of aquatic biota due to cooling water withdrawals and discharges.

The coal-fired alternative that AmerGen has defined in Section 7.2.1.1 would be located at an existing plant site.

Air Quality

A coal-fired plant would emit SO_2, NOx, particulate matter, mercury, and carbon monoxide, all of which are regulated pollutants. As Section 7.2.1.1 indicates, AmerGen has assumed a plant design that would minimize air emissions through a combination of boiler technology and post-combustion pollutant removal. Using data published by the Energy Information Administration (EIA 2002, EIA 2006b) and the EPA (EPA 1998a), the coal-fired alternative emissions are calculated to be as follows:

SO_2 = 5,241 tons per year

NOx = 690 tons per year

Carbon monoxide = 690 tons per year

Mercury = 0.11 tons per year

Particulates:

PM_{10} (particulates having a diameter of less than 10 microns) = 49 tons per year

$PM_{2.5}$ (particulates having a diameter of less than 2.5 microns) = 0.21 tons per year

The discussion in Section 7.2.2.1 of regional air quality is applicable to the coal-fired generation alternative. In addition, NRC noted in the GEIS that adverse human health effects from coal combustion have led to important federal legislation in recent years and that public health risks, such as cancer and emphysema, have been associated with coal combustion. NRC also mentioned global warming and acid rain as potential impacts. AmerGen concludes that federal legislation and large-scale concerns, such as global warming and acid rain, are indications of concerns about destabilizing important attributes of air resources. However, SO_2 emission allowances, NOx credits, low NOx burners, overfire air, fabric filters or electrostatic precipitators, and scrubbers are regulatorily-imposed mitigation measures. As such, AmerGen concludes that the coal-fired alternative would have MODERATE impacts on air quality; the impacts would be noticeable and greater than those of the gas-fired alternative, but would not destabilize air quality in the area.

Waste Management

AmerGen concurs with the GEIS assessment that the coal-fired alternative would generate substantial solid waste. The coal-fired plant would annually consume approximately 2,760,000 tons of coal having an ash content of 15.55 percent. After combustion, 90 percent of this ash, approximately 321,000 tons per year, would be marketed for beneficial reuse. The remaining ash, approximately 107,000 tons per year, would be collected and disposed of onsite, if space were available. In addition, if space were available, approximately 205,000 tons of scrubber sludge would be disposed of on site each year (based on annual limestone usage of about 172,000 tons). AmerGen estimates that ash and scrubber waste disposal over a 40-year plant life would require approximately 188 acres. If this acreage is not available at the existing power plant site where the new coal-fired unit would be sited, offsite disposal may be necessary, which would increase disposal impacts.

AmerGen believes that proper siting, current waste management practices, and current waste monitoring practices would prevent waste disposal from destabilizing any resources. After closure of the waste site and revegetation, the land would be available for other uses. For these reasons, AmerGen believes that waste disposal for the coal-fired alternative would have MODERATE impacts; the impacts of increased waste disposal would be noticeable, but would not destabilize any important resource, and further mitigation would be unwarranted.

Other Impacts

AmerGen estimates that construction of the power block and coal storage area would affect 129 acres of land and associated terrestrial habitat. Because much of this construction would be on previously disturbed land, impacts would be SMALL to MODERATE. Installation of a new rail spur or expansion of an existing spur would likely be required for coal and limestone deliveries under this alternative. Visual impacts would be consistent with the industrial nature of the site. As with any large construction project, some erosion and sedimentation and fugitive dust emissions could be anticipated, but would be minimized by using best management practices. Debris from clearing and grubbing could be disposed of onsite. AmerGen estimates a peak construction work force of 1,328. Socioeconomic impacts from the construction workforce would be minimal, if worker relocation is not required with a site located near a large metropolitan area. AmerGen estimates an operational workforce of 92 for the coal-fired alternative. This is a sizable reduction in operating personnel compared to TMI-1's 600-800 personnel, and the impact on the local community employment, taxes, housing, off-site land use, and public services could be significant. Thus, reduction in workforce would result in adverse socioeconomic impacts characterized as MODERATE.

Impacts to aquatic resources and water quality would be similar to impacts of TMI-1, due to the new plant's use of the cooling water from and discharge to the Susquehanna River or other natural water body, and would be offset by the concurrent shutdown of TMI-1. The stacks, boilers, and rail deliveries would increase the visual impact to the new site. Impacts to cultural resources would also be possible, but site surveys would be conducted to identify these resources and mitigate any impacts.

7.2.2.3 Purchased Power

As discussed in Section 7.2.1.2, AmerGen assumes that the generating technology used under the purchased power alternative would be one of those that NRC analyzed in the GEIS. AmerGen is also adopting by reference the NRC analysis of the environmental impacts from those technologies. Under the purchased power alternative, therefore, environmental impacts would still occur, but they would likely originate from a power plant located elsewhere in the PJM region. AmerGen believes that imports from outside the PJM region would not be required.

The existing transmission lines would be expected to transmit power to the south-central region of Pennsylvania, thus new lines would not be required. As a result, the impact would be SMALL. As indicated in the introduction to Section 7.2.1.1, the environmental impacts of construction and operation of new coal- or gas-fired generating capacity for purchased power at a previously undisturbed green field site would exceed those of a coal- or gas-fired alternative located at an existing power station.

Table 7.2-1. Gas-Fired Alternative

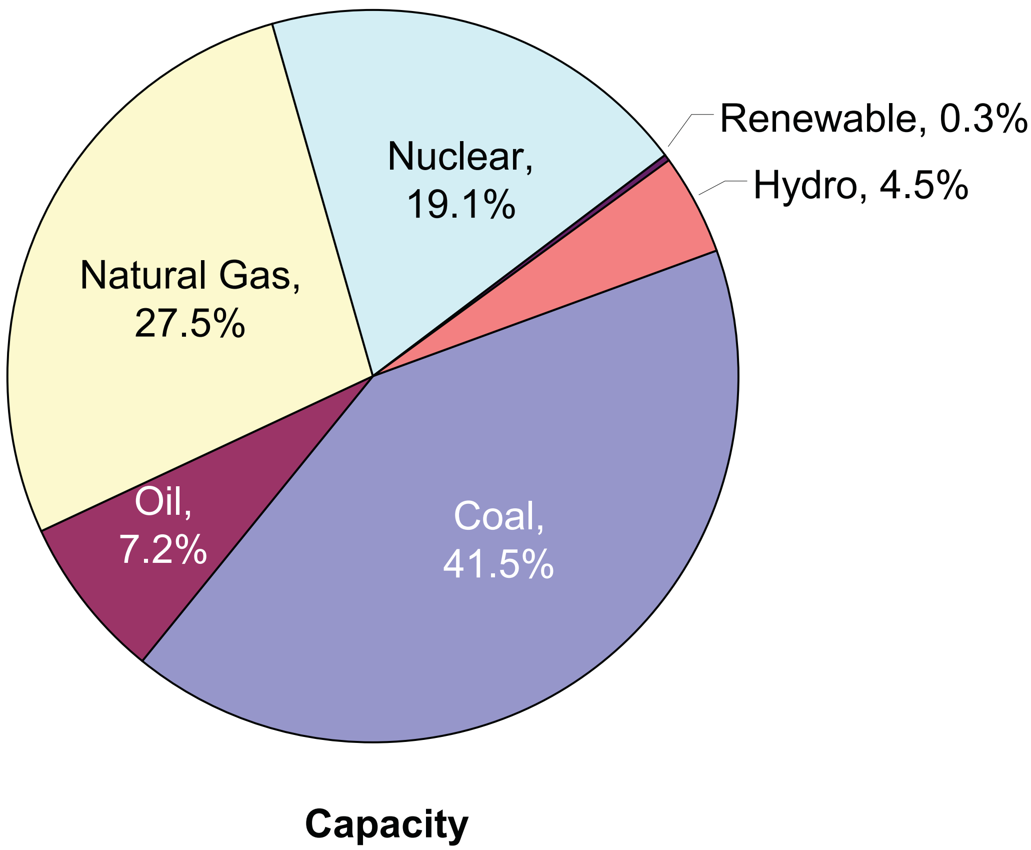
Characteristic	Basis
Unit size = 793 MWe ISO rating net combined cycle consisting of 263 MWe and 530 MWe systems with heat recovery steam generators (HRSGs)	Manufacturer's standard size gas-fired combined-cycle plant (≤ TMI-1 net capacity of 802 MWe)
Unit size = 826 MWe ISO rating gross	Based on 4 percent onsite power usage
Number of units = 1	Assumed
Fuel type = natural gas	Assumed
Fuel heating value = 1,033 Btu/ft^3	2004 value for gas used in Pennsylvania (EIA 2006b, Table 14.A)
Fuel SOx content = 0.0034 lb/MMBtu	EPA 2000, Table 3.1-2a
NOx control = selective catalytic reduction (SCR) with steam/water injection	Best available for minimizing NOx emissions (EPA 2000)
Fuel NOx content = 0.0090 lb/MMBtu	Typical for large SCR-controlled gas fired units with water injection (EPA 2000, Table 3.1 Database)
Fuel CO content = 0.0600 lb/MMBtu	Typical for large SCR-controlled gas fired units (EPA 2000, Table 3.1 Database)
Fuel PM_{10} content = 0.0019 lb/MMBtu	EPA 2000, Table 3.1-2a
Heat rate = 6,090 Btu/kWh	Chase and Kehoe 2000
Capacity factor = 0.85	Assumed based on performance of modern plants

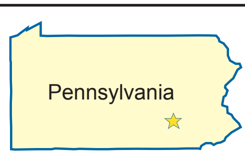
Note: The difference between "net" and "gross" is electricity consumed onsite.
Note: The HRSG does not contribute to air emissions.
Btu = British thermal unit
ft^3 = cubic foot
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch
kWh = kilowatt hour
MM = million
MWe = megawatt electrical
NOx = nitrogen oxides
PM^{10} = particulates having diameter of 10 microns or less
≤ = less than or equal to

Table 7.2-2. Coal-Fired Alternative

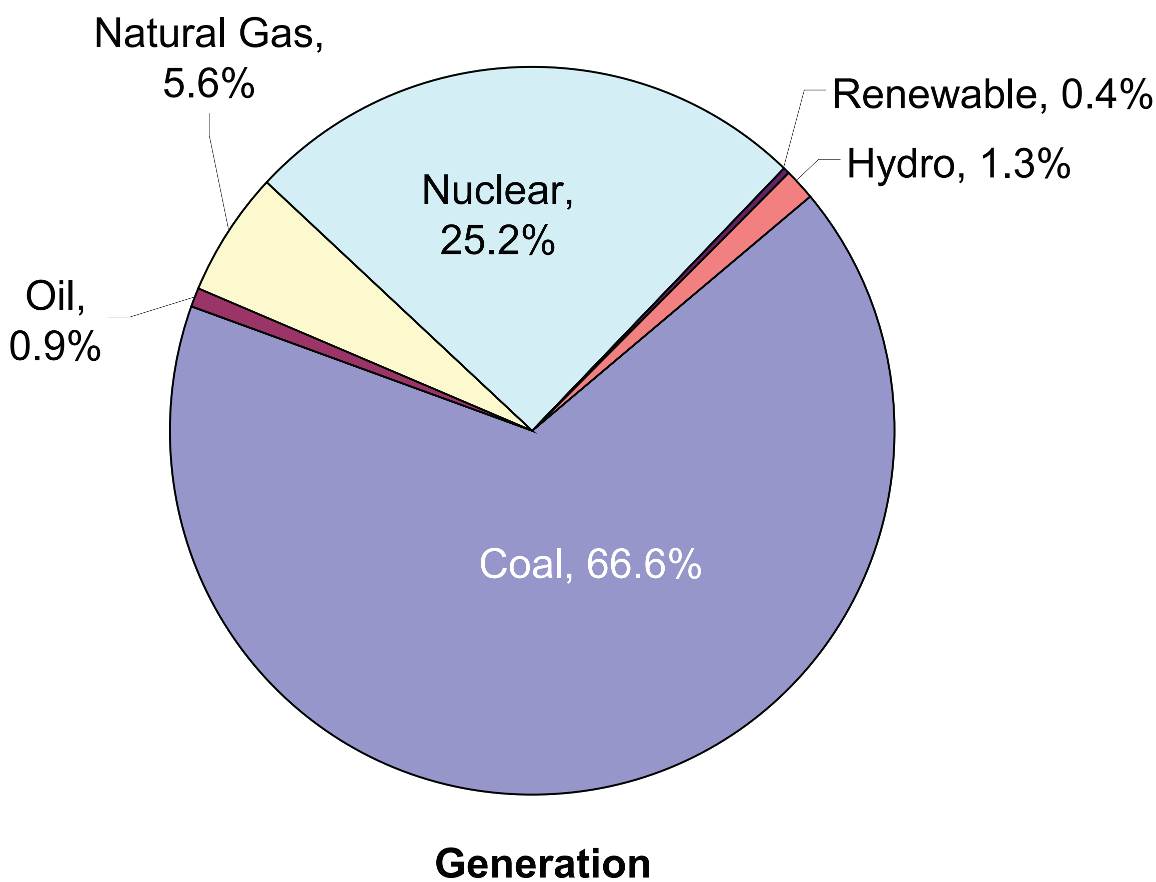
Characteristic	Basis
Unit size = 793 MWe ISO rating net	Size set = to gas-fired alternative (≤ TMI-1 net capacity of 802 MWe)
Unit size = 844 MWe ISO rating gross	Based on 6 percent onsite power usage
Number of units = 1	Assumed
Boiler type = tangentially fired, dry-bottom	Minimizes nitrogen oxides emissions (EPA 1998a)
Fuel type = bituminous, pulverized coal	Typical for coal used in Pennsylvania
Fuel heating value = 11,615 Btu/lb	2004 value for coal used in Pennsylvania (EIA 2006b, Table 15.A)
Fuel ash content by weight = 15.55 percent	2004 value for coal used in Pennsylvania (EIA 2006b, Table 15.A)
Fuel sulfur content by weight = 2.00 percent	2004 value for coal used in Pennsylvania (EIA 2006b, Table 15.A)
Uncontrolled NOx emission = 10 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS (EPA 1998a)
Uncontrolled CO emission = 0.5 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS (EPA 1998a)
Heat rate = 10,200 Btu/kWh	Typical for coal-fired boilers (EIA 2002)
Capacity factor = 0.85	Typical for large coal-fired units
NOx control = low NOx burners, over-fire air and selective catalytic reduction (95 percent reduction)	Best available and widely demonstrated for minimizing NOx emissions (EPA 1998a)
Particulate control = fabric filters (baghouse-99.9 percent removal efficiency)	Best available for minimizing particulate emissions (EPA 1998a)
SOx control = Wet scrubber - limestone (95 percent removal efficiency)	Best available for minimizing SOx emissions (EPA 1998a)

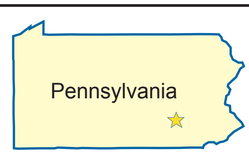
Note: The difference between “net” and “gross” is electricity consumed onsite.
Btu = British thermal unit
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch
kWh = kilowatt hour
NSPS = New Source Performance Standard
lb = pound
MWe = megawatt electrical
NOx = nitrogen oxides
SOx = oxides of sulfur
≤ = less than or equal to





Three Mile Island Nuclear Station Unit 1
License Renewal Environmental Report
Figure 7.2-1 PJM Regional Generating Capacity (2005)





Three Mile Island Nuclear Station Unit 1
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Figure 7.2-2 PJM Regional Energy Output by Fuel Type (2005)

7.3 REFERENCES

Note to reader: Some web pages cited in this document are no longer available, or are no longer available through the original URL addresses. Hard copies of cited web pages are available in AmerGen files. Some sites, for example the census data, cannot be accessed through their given URLs. The only way to access these pages is to follow queries on previous web pages. The complete URLs used by AmerGen have been given for these pages, even though they may not be directly accessible. Also, all references are specific to respective chapter.

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Chapter 8

COMPARISON OF ENVIRONMENTAL IMPACT OF LICENSE RENEWAL WITH THE ALTERNATIVES

NRC

"To the extent practicable, the environmental impacts of the proposal and the alternatives should be presented in comparative form..." 10 CFR 51.45(b)(3) as adopted by 51.53(c)(2)

Chapter 4 analyzes environmental impacts of the Three Mile Island Nuclear Station Unit 1 (TMI-1) license renewal and Chapter 7 analyzes impacts from renewal alternatives. Table 8.0-1 summarizes environmental impacts of the proposed action (license renewal) and the alternatives, for comparison purposes. The environmental impacts compared in Table 8.0-1 are those that are either Category 2 issues that apply to the proposed action or are issues that the Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) (NRC 1996) identified as major considerations in an alternatives analysis. For example, although the U.S. Nuclear Regulatory Commission (NRC) concluded that air quality impacts from the proposed action would be small (Category 1), the GEIS identified major human health concerns associated with air emissions from alternatives (Section 7.2.2). Therefore, Table 8.0-1 includes a comparison of the air impacts from the proposed action to those of the alternatives. Table 8.0-2 is a more detailed comparison of the alternatives.

Table 8.0-1. Impacts Comparison Summary

Impact	Proposed Action (License Renewal)	No-Action Alternatives			
		Base (Decommissioning)	With Coal-Fired Generation	With Gas-Fired Generation	With Purchased Power
Land Use	SMALL	SMALL	MODERATE	SMALL to MODERATE	MODERATE
Water Quality	SMALL	SMALL	SMALL	SMALL	SMALL to MODERATE
Air Quality	SMALL	SMALL	MODERATE	MODERATE	SMALL to MODERATE
Ecological Resources	SMALL	SMALL	MODERATE	SMALL	SMALL to MODERATE
Threatened or Endangered Species	SMALL	SMALL	SMALL	SMALL	SMALL
Human Health	SMALL	SMALL	MODERATE	SMALL	SMALL to MODERATE
Socioeconomics	SMALL	SMALL	SMALL	MODERATE	SMALL to MODERATE
Waste Management	SMALL	SMALL	MODERATE	SMALL	SMALL to MODERATE
Aesthetics	SMALL	SMALL	SMALL to MODERATE	SMALL	SMALL to MODERATE
Cultural Resources	SMALL	SMALL	SMALL	SMALL	SMALL

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource.

MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource. 10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 3.

Table 8.0-2. Impacts Comparison Detail

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternatives		
		With Coal-Fired Generation	With Gas-Fired Generation	With Purchased Power
Alternative Descriptions				
TMI-1 license renewal for 20 years, followed by decommissioning	Decommissioning following expiration of current TMI-1 license. Adopting by reference, as bounding TMI-1 decommissioning, GEIS description (NRC 1996, Section 7.1)	New construction at an existing power plant site	New construction at an existing power plant site	Would involve construction of new generation capacity in the PJM region. Adopting by reference GEIS description of alternate technologies (Section 7.2.1.2)
		Installation of a new rail spur	Construct 10-inch-diameter gas pipeline in a 50-foot-wide corridor. May require upgrades to existing pipelines	
		Construction of switchyard and transmission lines	Construction of switchyard and transmission lines	Construct new transmission lines to interconnect to the PJM region
		Single unit 793-MWe tangentially-fired, dry bottom units; capacity factor 0.85	Two pre-engineered natural gas fired systems, with heat recovery steam generators, producing combined total of 793 MWe; capacity factor 0.85	

Table 8.0-2. Impacts Comparison Detail (Continued).

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternatives: With Coal-Fired Generation	No-Action Alternatives: With Gas-Fired Generation	No-Action Alternatives: With Purchased Power
		Construct intake/ discharge canal system	Construct intake/ discharge canal system	
		Pulverized bituminous coal, 11,615 Btu/lb; 10,200 Btu/kWh; 15.55% ash; 2.0% sulfur; 10 lb/ton nitrogen oxides; 2,758,159 tons coal/yr	Natural gas, 1,033 Btu/ft3; 6,090 Btu/kWh; 0.0034 lb sulfur/MMBtu; 0.0090 lb NOx/MMBtu; 36,238,318,762 ft3 gas/yr	
		Low NOx burners, over-fire air and selective catalytic reduction (95% NOx reduction efficiency)	Selective catalytic reduction with steam/water injection	
		Wet scrubber – lime/limestone desulphurization system (95% SOx removal efficiency); 172, 030 tons lime/yr		
		Fabric filters or electrostatic precipitators (99.9% particulate removal efficiency)		

Table 8.0-2. Impacts Comparison Detail (Continued).

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternatives		
		With Coal-Fired Generation	With Gas-Fired Generation	With Purchased Power
525 permanent and 170 long-term contract workers		92 workers (Section 7.2.2.2)	27 workers (Section 7.2.2.1)	
Land Use Impacts				
SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issues 52, 53)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	MODERATE – 129 acres required for the power block and associated facilities; 188 acres for ash disposal (Section 7.2.2.2)	SMALL to MODERATE – 32 acres for facility at TMI-1 location (Section 7.2.2.1). New gas pipeline would be built to connect with existing gas pipeline corridor	MODERATE – most transmission facilities could be constructed along existing transmission corridors (Section 7.2.2.3). Adopting by reference GEIS description of land use impacts from alternate technologies (NRC 1996)
Water Quality Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 1-3, 6-11, and 31). Three Category 2 groundwater issues apply (Section 4.1, Issue 13; and Section 4.5, Issue 33; Section 4.6, Issue 34). Two Category 2 groundwater issues don't apply (Section 4.7, Issue 35; and Section 4.8, Issue 39).	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 89).	SMALL – Construction impacts minimized by use of best management practices. Operational impacts similar to TMI-1 by using cooling water and discharge to the Susquehanna River. (Section 7.2.2.2)	SMALL – Reduced cooling water demands, inherent in combined-cycle design (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of water quality impacts from alternate technologies (NRC 1996)

Table 8.0-2. Impacts Comparison Detail (Continued).

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternatives: With Coal-Fired Generation	No-Action Alternatives: With Gas-Fired Generation	No-Action Alternatives: With Purchased Power
Air Quality Impacts				
SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 51). Category 2 issue finding (Section 4.11, Issue 50).	SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issue 88)	MODERATE – 5,241 tons SOx/yr 690 tons NOx/yr 690 tons CO/yr 214 tons TSP/yr 0.21 tons PM-2.5/yr 49 tons PM-10/yr (Section 7.2.2.2)	MODERATE – 64 tons SOx/yr 168 tons NOx/yr 1,123 tons CO/yr 36 tons PM-2.5/yra (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of air quality impacts from alternate technologies (NRC 1996)
Ecological Resource Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 14-24, 28-30, 43, and 45-48). One Category 2 issues findings (Section 4.9, Issue 40). Three Category 2 issues not applicable (Section 4.2, Issue 25; Section 4.3, Issue 26; and Section 4.4, Issue 27)	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 90)	MODERATE – 188 acres of undisturbed land could be required for ash/sludge disposal over 20-year license renewal term. (Section 7.2.2.2)	SMALL – Construction of pipeline could alter the terrestrial habitat. (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of ecological resource impacts from alternate technologies (NRC 1996)

Table 8.0-2. Impacts Comparison Detail (Continued).

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternatives		
		With Coal-Fired Generation	With Gas-Fired Generation	With Purchased Power
Threatened or Endangered Species Impacts				
SMALL – No Federally threatened or endangered species are known residents at the site or along the transmission corridors. (Section 4.10, Issue 49)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats
Human Health Impacts				
SMALL – Adopting by reference Category 1 issues (Table A-1, Issues 54-56, 58, 61, 62). One Category 2 issue does apply (Section 4.12, Issue 57). Risk due to transmission-line induced currents minimal due to conformance with consensus code (Section 4.13, Issue 59)	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 86)	MODERATE – Adopting by reference GEIS conclusion that risks such as cancer and emphysema from emissions are likely (NRC 1996)	SMALL – Adopting by reference GEIS conclusion that some risk of cancer and emphysema exists from emissions (NRC 1996)	SMALL to MODERATE – Adopting by reference GEIS description of human health impacts from alternate technologies (NRC 1996)

Table 8.0-2. Impacts Comparison Detail (Continued).

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternatives		
		With Coal-Fired Generation	With Gas-Fired Generation	With Purchased Power
Socioeconomic Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 64, 67). Two Category 2 issues findings (Section 4.16, Issue 66 and Section 4.17, Issue 68). Location in high population area with no growth controls minimizes potential for housing impacts. Section 4.14, Issue 63). Plant property tax payment represents less than 1 percent of county's total tax revenues (Section 4.17, Issues 68 and 69). Capacity of public water supply and transportation infrastructure minimizes potential for related impacts (Section 4.15, Issue 65; Section 4.16, Issue 66 and Section 4.18, Issue 70)	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 91)	SMALL – Reduction in permanent work force at TMI-1 could adversely affect surrounding counties, but would be mitigated by TMI-1's proximity to several metropolitan areas (Section 7.2.2.2)	SMALL to MODERATE – Reduction in permanent work force at TMI-1 could adversely affect surrounding counties, but would be mitigated by TMI-1's proximity to several metropolitan areas (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of socioeconomic impacts from alternate technologies (NRC 1996)

Table 8.0-2. Impacts Comparison Detail (Continued).

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternatives		
		With Coal-Fired Generation	With Gas-Fired Generation	With Purchased Power
Waste Management Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 77-85)	SMALL – Adopting by reference Category 1 issue finding (Table A-1, Issue 87)	MODERATE – 107,000 tons of coal ash and 205,000 tons of scrubber sludge annually would require 188 acres over 20-year license renewal term. (Section 7.2.2.2)	SMALL – Approximately 500 ft3 spent SCR catalyst per year (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of waste management impacts from alternate technologies (NRC 1996)
Aesthetic Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table A-1, Issues 73, 74)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	SMALL to MODERATE – The coal-fired power blocks and the exhaust stacks would be visible from offsite, in an industrial setting (Section 7.2.2.2)	SMALL– Steam turbines and stacks would create visual impacts comparable to those from existing TMI-1 facilities (Section 7.2.2.1)	SMALL to MODERATE – Adopting by reference GEIS description of aesthetic impacts from alternate technologies (NRC 1996)
Cultural Resource Impacts				
SMALL – SHPO consultation minimizes potential for impact (Section 4.19, Issue 71)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	SMALL – Impacts to cultural resources would be unlikely due to developed nature of the site (Section 7.2.2.2)	SMALL – Construction in previously disturbed soil would be unlikely to affect cultural resources (Section 7.2.2.1)	SMALL – Adopting by reference GEIS description of cultural resource impacts from alternate technologies (NRC 1996)

Table 8.0-2. Impacts Comparison Detail (Continued).

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternatives		
		With Coal-Fired Generation	**With Gas-Fired Generation**	**With Purchased Power**

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource.

MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource. (10 CFR 51, Subpart A, Appendix B, Table B 1, Footnote 3).

[a]. All TSP for gas-fired alternative is PM-2.5.

Btu	=	British thermal unit	NOx	=	nitrogen oxide
ft3	=	cubic foot	PJM	=	regional electric distribution network
gal	=	gallon	PM-2.5	=	particulates having diameter less than 2.5 microns
GEIS	=	Generic Environmental Impact Statement (NRC 1996)	SHPO	=	State Historic Preservation Officer
kWh	=	kilowatt hour	SOx	=	sulfur dioxide
lb	=	pound	TSP	=	total suspended particulates
MM	=	million	yr	=	year
MW	=	megawatt			

8.1 REFERENCES

NRC (U.S. Nuclear Regulatory Commission). 1996. Generic Environmental Impact Statement for License Renewal of Nuclear Plants. Volumes 1 and 2. NUREG-1437. Washington, DC. May.

Chapter 9

Status of Compliance

9.1 PROPOSED ACTION

NRC

"The environmental report shall list all federal permits, licenses, approvals and other entitlements which must be obtained in connection with the proposed action and shall describe the status of compliance with these requirements. The environmental report shall also include a discussion of the status of compliance with applicable environmental quality standards and requirements including, but not limited to, applicable zoning and land-use regulations, and thermal and other water pollution limitations or requirements which have been imposed by Federal, State, regional, and local agencies having responsibility for environmental protection." 10 CFR 51.45(d), as adopted by 10 CFR 51.53(c)(2)

9.1.1 GENERAL

Table 9.1-1 lists environmental authorizations that AmerGen Energy Company, LLC (AmerGen) has obtained for current Three Mile Island Nuclear Station Unit 1 (TMI-1) operations. In this context, AmerGen uses "authorizations" to include any permits, licenses, approvals, or other entitlements. AmerGen expects to continue renewing these authorizations during the current license period and throughout the period of extended operation under the renewed U.S. Nuclear Regulatory Commission (NRC) license. Because the NRC regulatory focus is prospective, Table 9.1-1 does not include authorizations that AmerGen obtained for past activities that did not include continuing obligations.

To support its application for renewal of the TMI-1 license to operate, AmerGen assessed whether new and significant environmental information exists relative to the information considered by the NRC in preparing the *Generic Environmental Impact Statement For License Renewal* (see Chapter 5). The assessment included interviews with subject matter experts at TMI-1, a review of TMI-1 environmental documentation, and communications with state and federal environmental protection agencies. Based on this assessment, AmerGen concludes that TMI-1 is in compliance with applicable environmental standards and requirements.

Table 9.1-2 lists additional environmental authorizations and consultations related specifically to renewal by the NRC of the TMI-1 license to operate. As indicated, AmerGen anticipates needing relatively few such authorizations and consultations. Sections 9.1.2 through 9.1.4 discuss some of these items in more detail.

Table 9.1-3 lists potentially required authorizations associated with conducting refurbishment activities.

9.1.2 THREATENED OR ENDANGERED SPECIES

Section 7 of the Endangered Species Act (16 USC 1531 et seq.) requires federal agencies to ensure that agency action is not likely to jeopardize any species that is listed, or proposed for listing as endangered, or threatened. Depending on the agency action involved, the Act requires consultation either with the U.S. Fish and Wildlife Service (FWS) (regarding effects on non-marine species), or the National Marine Fisheries Service (NMFS) (regarding effects on marine species), or both. FWS and NMFS have issued joint procedural regulations at 50 Code of Federal Regulations (CFR) 402, Subpart B, that address consultation, and FWS maintains the joint list of threatened and endangered species at 50 CFR 17.

Although not required of an applicant by federal law or NRC regulation, AmerGen has chosen to invite comment from federal and state agencies regarding potential effects that renewal of the TMI-1 license might have. Appendix C includes copies of AmerGen correspondence with FWS, Pennsylvania Department of Conservation and Natural Resources, the Pennsylvania Game Commission, and the Pennsylvania Fish and Boat Commission.

9.1.3 HISTORIC PRESERVATION

Section 106 of the National Historic Preservation Act (16 USC 470 et seq.) requires federal agencies having the authority to license any undertaking to, prior to issuing the license, take into account the effect of the undertaking on historic properties and to afford the Advisory Council on Historic Preservation an opportunity to comment on the undertaking. Council regulations provide for the State Historic Preservation Officer (SHPO) to have a consulting role (35 CFR 800.2). Although not required of an applicant by federal law or NRC regulation, AmerGen has chosen to invite comment by the Pennsylvania SHPO. Appendix D contains a copy of AmerGen's letter to the Pennsylvania SHPO and the SHPO's response. The SHPO stated, "in our opinion the activities described in your proposal should have no effect on these resources." Therefore, the SHPO agrees that license renewal will have no adverse effect on significant cultural resources within the project area.

9.1.4 WATER QUALITY (401) CERTIFICATION

Federal Clean Water Act Section 401 requires an applicant seeking a federal license for an activity that may result in a discharge to navigable waters to provide the licensing agency with a certification by the state where the discharge would originate indicating that applicable state water quality standards will not be violated as a result of the discharge (33 USC 1341). The Commonwealth of Pennsylvania issued a Section 401 State Water Quality Certification for the TMI nuclear station on November 9, 1977 (included in Appendix B). Now, AmerGen is applying for NRC approval to extend TMI-1 operations under a renewed license.

The NRC has indicated in its Generic Environmental Impact Statement for License Renewal that issuance of an NPDES permit by a state implies continued Section 401 certification by the state (NRC 1996, Section 4.2.1.1). The Commonwealth of Pennsylvania has EPA authorization to implement the NPDES permitting program. In addition, guidance published by the Pennsylvania Department of Environmental Protection (PADEP) states that water quality certifications have been integrated with other required permits and that individual water quality certifications will be issued only for activities that are not regulated by other water quality approvals or permits. Accordingly, as evidence of continued Section 401 certification by Pennsylvania, AmerGen is providing the existing TMI-1 NPDES permit (PA0009920) (included in Appendix B).

9.2 ALTERNATIVES

NRC

"The discussion of alternatives in the report shall include a discussion of whether the alternatives will comply with such applicable environmental quality standards and requirements." 10 CFR 51.45(d), as required by 10 CFR 51.53(c)(2)

The coal, gas, and purchased power alternatives discussed in Section 7.2 probably could be constructed and operated to comply with applicable environmental quality standards and requirements. AmerGen notes that increasingly stringent air quality protection requirements could make the construction of a large fossil-fueled power plant infeasible in many locations. AmerGen also notes that the U.S. Environmental Protection Agency is in the process of revising requirements for design and operation of cooling water intake structures at new and existing facilities (40 CFR 125 Subparts I and J). The new requirements could necessitate construction of cooling towers for the coal- and gas-fired alternatives.

Table 9.1-1. Existing Environmental Authorizations for TMI-1 Operations

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
Federal and State Requirements					
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011, et seq.), 10 CFR 50.10	License to operate	Docket 50-289	Issued: 4/19/74 Expires: 4/19/14	Operation of TMI-1
Susquehanna River Basin Commission	Susquehanna River Basin Compact, P.L. 91-575, Article 3, Section 3.10, P.L. 91-575, and Commission Regulation 803.61	Consumptive Water Use Permit	Docket 19950302	Issued: 3/14/80 Expires: 3/14/10	Consumptive Water Use of up to 18,000,000 gpd (on a 30-day average) for electric power generation
Susquehanna River Basin Commission	Susquehanna River Basin Compact, P.L. 91-575, Article 3, Section 3.10, P.L. 91-575, and Commission Regulation 803.43	Groundwater Withdrawal Permit	Docket 19961102	Issued: 1/26/99 Expires: 11/26/21	Groundwater Withdrawal of up to 225,000 gpd (on a 30-day average) for industrial use
Pennsylvania Department of Environmental Protection	Air Pollution Control Act, P.L. 2119 and 25 Pa. Code Chapter 127	Synthetic Minor Operating Permit	22-05029	Issued:1/1/07 Expires:12/31/11	All air emission sources at TMI-1
Pennsylvania Department of Environmental Protection	Clean Water Act, 33 U.S.C. Section 1251 et seq. and Pennsylvania's Clean Streams Law, as amended, 35 P.S. Section 691.1 et seq.	NPDES permit	PA 0009920	Issued: 10/30/07 Expires: 10/31/12 (Administratively Extended Pending New Permit Issuance)	Authorization to discharge into the Susquehanna River

Table 9.1-1. Existing Environmental Authorizations for TMI-1 Operations (continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
Federal and State Requirements					
U.S. Army Corps of Engineers	Pennsylvania Public Laws 834, 204, 851, 1987, etc.	Maintenance dredging permit	CENAB-OP-RPA (AmerGen Energy Company, LLC) 197500083-4	Issued: 1/3/06 Expires: 12/31/15	Maintenance dredging of the TMI-1 Intake Bay in the Susquehanna River
Pennsylvania Department of Environmental Protection	P.L. 555, as amended	Maintenance Dredging Permit	21275724	Issued: 01/13/76 Expires: No Date Listed on Permit	Maintenance dredging of the intake bay in the Susquehanna River
Pennsylvania Department of Environmental Protection	Pennsylvania Safe Drinking Water Act (P.L. 206, No. 43)	Public Water Supply Permit	22296501-T1	Issued: 01/20/00 Expires: No Date Listed on Permit	Operation of TMI-1 Plant Site Drinking Water System
Pennsylvania Department of Environmental Protection	Pennsylvania Safe Drinking Water Act (P.L. 206, No. 43)	Public Water Supply Permit	22295502-T1	Issued: 01/20/00 Expires: No Date Listed on Permit	Operation of TMI-1 Training Center Drinking Water System
U.S. Environmental Protection Agency	RCRA Section 310	Acknowledgement of Notification of Regulated Waste Activity	PAR 000037861	Issued: 3/22/99 Expires: No Date Listed on Permit	Generation and transportation of hazardous waste
Pennsylvania Department of Environmental Protection	Pennsylvania Storage Tank and Spill Prevention Act and 25 PA Code 245	Storage Tank Registration/Permit Certificate	22-60170	Issued: 6/4/07 Expires: 6/4/08 (Annual Renewal)	Registration of storage tanks

Table 9.1-1. Existing Environmental Authorizations for TMI-1 Operations (continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
Federal and State Requirements					
U.S. Department of Transportation	49 CFR Part 107, Subpart G and 49 U.S.C. 5108	Hazardous Materials Certificate of Registration	022307-701-002PR	Issued: 5/16/07 Expires: 6/30/10	Hazardous Materials transportation
Pennsylvania Department of Labor and Industry, Boiler Section	Pennsylvania Fire Marshall	Flammable and Combustible Liquid Storage Tank Approval	168,466	Issued: 6/12/70 Expires: No Date Listed on Permit	Construction and Operation of TMI-1 50,000-gallon aboveground diesel fuel oil tank.
Pennsylvania Department of Labor and Industry, Boiler Section	Pennsylvania Fire Marshall	Flammable and Combustible Liquid Storage Tank Approval	168,465	Issued: 6/12/70 Expires: No Date Listed on Permit	Construction and Operation of TMI-1 30,000-gallon underground diesel fuel oil tank.
Pennsylvania Department of Labor and Industry, Boiler Section	Pennsylvania Fire Marshall	Flammable and Combustible Liquid Storage Tank Approval	187,165	Issued: 11/17/77 Expires: No Date Listed on Permit	Construction and Operation of TMI-1 200,000-gallon aboveground diesel fuel oil tank.
Pennsylvania Department of Labor and Industry, Boiler Section	Pennsylvania Fire Marshall	Flammable and Combustible Liquid Storage Tank Approval	203,271-B	Issued: 8/4/89 Expires: No Date Listed on Permit	Construction and Operation of TMI-1 Fire Training Facility 285-gallon aboveground diesel fuel oil tank.

Table 9.1-1. Existing Environmental Authorizations for TMI-1 Operations (continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
Federal and State Requirements					
Pennsylvania Department of Labor and Industry, Boiler Section	Pennsylvania Fire Marshall	Flammable and Combustible Liquid Storage Tank Approval	122-203,393	Issued: 9/22/89 Expires: None	Construction and Operation of TMI-1 Transportation Department USTs (4,000-gallon diesel and 10,000 gallon gasoline)
Pennsylvania Department of Environmental Protection	Londonderry Township	Sewage Disposal System Permit Modification	C179678 and C21434	Issued: 1/1/95 Expires: No Date Listed on Permit	Approval of additional flows to Visitors Center and Training Center elevated sand mounds.
Pennsylvania Department of Environmental Protection	Water Quality Management Division	Sewage Sludge Disposal Agreement	Letter Agreement	Issued: 6/20/00 Expires: No Date Listed on Permit	Disposal of sewage sludge.
Pennsylvania Department of Environmental Protection	Bureau of Laboratory Certification	Environmental Laboratory Accreditation Certification	Reg. No. 22-00649	Issued: 04/17/07 Expires: 04/30/08	TMI-1 Chemistry Laboratory is certified to perform accredited analyses for NPDES reporting
Pennsylvania Department of Environmental Protection	Londonderry Township	On Lot Sewage Disposal System Permit	U003282	Issued: 08/10/07 Expires: No Date Listed on Permit	New Sand Mound System for TMI-1 Training Center

Table 9.1-2. Environmental Authorizations Needed to Continue TMI-1 Operation During the Period of License Renewal

Agency	Authority	Requirement	Remarks
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011 et seq.)	License renewal	Environmental Report submitted in support of license renewal application
U.S. Fish and Wildlife Service (FWS)	Endangered Species Act Section 7 (16 USC 1536)	Consultation	Requires federal agency issuing a license to consult with the FWS (Attachment C)
Pennsylvania Department of Environmental Protection	Clean Water Act Section 401 (33 USC 1341)	Certification	State issuance of NPDES permit (Attachment B) constitutes 401 certification (1977 certification included in Attachment B) (Section 9.1.4)
Pennsylvania Historical and Museum Commission	National Historic Preservation Act Section 106 (16 USC 470f)	Consultation	Requires federal agency issuing a license to consider cultural impacts and consult with State Historic Preservation Officer (SHPO). SHPO must concur that license renewal will not affect any sites listed or eligible for listing (Attachment D)

Note: No renewal-related requirements identified for local or other agencies.

Table 9.1-3 Environmental Authorizations Potentially Needed for TMI-1 Refurbishment Activities

Responsible Agency	Authority	Requirement	Status
		AIR QUALITY PROTECTION	
Pennsylvania Department of Environmental Protection (PADEP)	CAA, Title V, Sections 501-507 (42 U.S.C. 7661-7661f); PA Code Chapter 127	Requires approval (operating permit) by the PADEP for construction or modification of an air pollutant source.	TMI-1 currently holds a *Synthetic Minor Operating Permit* (No. 22-05029), which allows the emission of air pollutants from the TMI-1 site, provided that federally enforceable restrictions are placed on the emissions such that total site emissions will not exceed the threshold for becoming a major source. AmerGen is reviewing the need to modify the existing permit or apply for a new permit for temporary emissions associated with the following steam generator replacement project air pollutant emission sources: concrete batch plant; fuel oil delivery and storage; painting; sandblasting; generator and truck exhausts; fugitive dust; nitrogen purge release. If permitting action is determined to be required, AmerGen will file an application at the appropriate time.
		PROTECTION OF WATER RESOURCES	
PADEP	Clean Water Act of 1977 (CWA) (33 U.S.C. 1251 et seq.); 25 PA Code Chapter 92	Requires a National Pollutant Discharge Elimination System (NPDES) permit prior to any discharge of pollutants from a point source into surface waters.	TMI-1 currently holds an *NPDES Permit* (No. PA 0009920), which authorizes pollutant discharges into the Susquehanna River. AmerGen is reviewing the need to modify the existing NPDES permit, or otherwise obtain authorization for the following temporary discharges to surface waters associated with steam generator replacement project activities: discharge of treated water from hydro demolition (used to cut the opening through the outside concrete wall of the reactor containment building); discharge of storm water from disturbed area during construction; and discharge of concrete truck washout water. If permitting action is determined to be required, AmerGen will file an application at the appropriate time.
PADEP	Clean Streams Law (35 P.S. 691.201, 691.202, 691.207 and 691.402); 25 PA Code Chapter 72	Requires permits for large volume, on lot sewage systems.	TMI-1 currently holds an *On Lot Sewage Disposal System Permit* (No. U003282). AmerGen has determined that no permit modification is needed to support the steam generator replacement project. The existing system is adequately sized to meet the demands of the steam generator replacement project. In addition, a service contract for portable toilets may be implemented at the site during the steam generator replacement project.

Table 9.1-3 Environmental Authorizations Potentially Needed for TMI-1 Refurbishment Activities (continued)

Responsible Agency	Authority	Requirement	Status
U.S. Environmental Protection Agency (EPA)	CWA (33 U.S.C. 1251 et seq.); 40 CFR Part 112	Requires a Spill Prevention Control and Countermeasures (SPCC) Plan for any facility that could discharge oil in harmful quantities into navigable waters.	AmerGen is reviewing the existing TMI-1 SPCC Plan and will, as appropriate, modify it or develop a separate SPCC Plan for activities associated with steam generator replacement project activities.
Susquehanna River Basin Commission (SRBC)	Susquehanna River Basin Compact, P.L. 91-575, Article 3, Section 3.10; 18 CFR Part 806; 25 PA Code Chapter 806	Requires review and approval of any project that will result in consumptive use of water from the Susquehanna River.	TMI-1 holds a *Consumptive Water Use Permit* (Docket 19950302) for up to 18,000,000 gpd (on a 30-day average) for electric power generation. AmerGen is reviewing whether a modification to this permit is necessary to supply water for steam generator replacement project activities, especially hydro-demolition. If permitting action is determined to be necessary, Amergen will file an application at the appropriate time.
Susquehanna River Basin Commission	Susquehanna River Basin Compact, P.L. 91-575, Article 3, Section 3.10; 18 CFR Part 807; 25 PA Code Chapter 807	Requires any person withdrawing or diverting in excess of an average of 10,000 gpd for any consecutive 30-day period, from ground or surface Susquehanna River water sources to register the amount of withdrawal.	TMI-1 holds a *Water Withdrawal Permit* (Docket 19961102) for groundwater withdrawal of up to 225,000 gpd (on a 30-day average) for industrial use. AmerGen is reviewing whether the steam generator replacement project activities will require additional groundwater or surface water withdrawal. If so, an application will be filed with the SRBC at the appropriate time.
U.S. Army Corps of Engineers	CWA (33 U.S.C. 1251 et seq.)	Requires that a *CWA Section 404 Permit* be issued for the discharge of dredge or fill material into waters of the U.S., including wetlands.	AmerGen is reviewing options for transport of the new steam generators from a U.S. port of call to TMI-1. If the selected option, or any other activity associated with the steam generator replacement project, would involve dredge or fill activities, AmerGen or its contractor will apply for the required approval at the appropriate time.
PADEP	Flood Plain Management Act (32 P. S. 679.101—679.601); 25 PA Code Chapter 106	Requires that a permit be obtained before construction, modification, removal, destruction or abandonment of an obstruction in a floodplain.	AmerGen is reviewing flood plain elevations and will avoid steam generator replacement activities within the flood plain to the extent practicable. If avoidance is not practicable, AmerGen will obtain the necessary permits at the appropriate time.

Table 9.1-3 Environmental Authorizations Potentially Needed for TMI-1 Refurbishment Activities (continued)

Responsible Agency	Authority	Requirement	Status
WASTE MANAGEMENT AND POLLUTION PREVENTION			
PADEP	Resource Conservation and Recovery Act (RCRA), as amended by the Hazardous and Solid Waste Amendments of 1984 (HSWA) (42 U.S.C. 6901 et seq.), Subtitle I; Storage Tank and Spill Prevention Act (35 P. S. 6021.101—6021.2104); 25 PA Code Chapter 245	Requires that a permit be obtained before operating or installing certain aboveground and underground storage tanks.	AmerGen is reviewing the contents and sizes of proposed aboveground and underground storage tanks associated with steam generator replacement activities. If any tanks are identified that are not covered by an exemption or permit-by-rule, AmerGen will apply for a storage tank permit at the appropriate time.
PADEP	RCRA, as amended by HSWA (42 U.S.C. 6901 et seq.), Subtitle C; Solid Waste Management Act (35 P. S. 6018.105, 6018.401—6018.403 and 6018.501); 25 PA Code Articles VII (Hazardous Waste Management) and IX (Residual Waste Management)	Requires that waste generators characterize their wastes and ensure compliance with applicable requirements for treatment, storage, disposal, and transportation.	AmerGen will characterize all wastes generated by steam generator replacement activities to determine applicable requirements for treatment, storage, disposal, and transportation of the wastes. Possible waste categories include low-level radioactive waste, nonradioactive hazardous waste, mixed waste, nonradioactive nonhazardous solid waste, and residual waste. All wastes will be treated, stored, disposed, and transported in accordance with applicable requirements, based on characterization results. Permits, if required, will be obtained at the appropriate time.

Table 9.1-3 Environmental Authorizations Potentially Needed for TMI-1 Refurbishment Activities (continued)

Responsible Agency	Authority	Requirement	Status
BIOTIC RESOURCES			
U.S. Fish and Wildlife Service; PA Game Commission	Bald and Golden Eagle Protection Act (16 USC 668 – 668d); Endangered Species Act Section 7 (16 USC 1536); 34 PA Game and Wildlife Code Sec. 2924	Prohibits taking of bald eagles and other birds or animals classified by the U.S. Fish and Wildlife Service or the PA Game Commission as endangered or threatened species, and prohibits interfering with or destroying the active nest or eggs of a protected bird, unless a permit has been issued for such activity.	AmerGen is reviewing nest locations and activities of peregrine falcons, osprey, and bald eagles in the vicinity of the TMI-1 reactor containment building. If it is determined that activities associated with the steam generator replacement project warrant obtaining a permit from the PA Game Commission and/or the U.S. Fish and Wildlife service, an application will be filed at the appropriate time.
OTHER			
Federal Aviation Administration	14 CFR Part 77	Requires notice to the FAA of proposed construction that could obstruct air navigation	AmerGen will evaluate the height of cranes and structures associated with the steam generator replacement project. If it is determined that a notice to the FAA is required, the notice will be filed at the appropriate time.
Pennsylvania Department of Transportation	67 PA Code Chapter 179	Requires a permit for movement on a Pennsylvania highway of an oversize or overweight vehicle, including the load.	AmerGen is reviewing options for transport of the new steam generators from a U.S. port of call to TMI-1. If the selected option would involve moving the steam generators or other oversize or overweight loads over Pennsylvania highways or the highways of other states, AmerGen or its contractor will apply for the required approval at the appropriate time.

9.3 REFERENCES

NRC (U.S. Nuclear Regulatory Commission). 1996. Generic Environmental Impact Statement for License Renewal of Nuclear Plants. Volumes 1 and 2. NUREG-1437. Washington, DC. May.

Appendix A

NRC NEPA Issues for License Renewal of Nuclear Power Plants

AmerGen has prepared this environmental report in accordance with the requirements of U.S. Nuclear Regulatory Commission (NRC) regulation 10 CFR 51.53. NRC included in the regulation a list of National Environmental Policy Act (NEPA) issues for license renewal of nuclear power plants.

Table A-1 lists these 92 issues and identifies the section in which AmerGen addressed each applicable issue in this environmental report. For organization and clarity, AmerGen has assigned a number to each issue and uses the issue numbers throughout the environmental report.

Table A-1. TMI-1 Environmental Report Discussion of License Renewal NEPA Issues[a]

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
Surface Water Quality, Hydrology, and Use (for all plants)			
1. Impacts of refurbishment on surface water quality	1	4.0	3.4.1/3-4
2. Impacts of refurbishment on surface water use	1	4.0	3.4.1/3-4
3. Altered current patterns at intake and discharge structures	1	4.0	4.2.1.2.1/4-5
4. Altered salinity gradients	1	NA	Issue applies to an activity, discharge to saltwater, which TMI-1 does not do.
5. Altered thermal stratification of lakes	1	NA	Issue applies to an activity, discharge to a lake, which TMI-1 does not do.
6. Temperature effects on sediment transport capacity	1	4.0	4.2.1.2.3/4-8
7. Scouring caused by discharged cooling water	1	4.0	4.2.1.2.3/4-6
8. Eutrophication	1	4.0	4.2.1.2.3/4-9
9. Discharge of chlorine or other biocides	1	4.0	4.2.1.2.4/4-10
10. Discharge of sanitary wastes and minor chemical spills	1	4.0	4.2.1.2.4/4-10
11. Discharge of other metals in waste water	1	4.0	4.2.1.2.4/4-10
12. Water use conflicts (plants with once-through cooling systems)	1	NA	Issue applies to a plant feature, once-through cooling, which TMI-1 does not have.
13. Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	2	4.1	4.3.2.1/4-29
Aquatic Ecology (for all plants)			
14. Refurbishment impacts to aquatic resources	1	4.0	3.5/3-5
15. Accumulation of contaminants in sediments or biota	1	4.0	4.2.1.2.4/4-10
16. Entrainment of phytoplankton and zooplankton	1	4.0	4.2.2.1.1/4-15
17. Cold shock	1	4.0	4.2.2.1.5/4-18
18. Thermal plume barrier to migrating fish	1	4.0	4.2.2.1.6/4-19

Table A-1. TMI-1 Environmental Report Discussion of License Renewal NEPA Issues[a] (continued)

Issue	Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
19. Distribution of aquatic organisms	1	4.0	4.2.2.1.6/4-19
20. Premature emergence of aquatic insects	1	4.0	4.2.2.1.7/4-20
21. Gas supersaturation (gas bubble disease)	1	4.0	4.2.2.1.8/4-21
22. Low dissolved oxygen in the discharge	1	4.0	4.2.2.1.9/4-23
23. Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	1	4.0	4.2.2.1.10/4-24
24. Stimulation of nuisance organisms (e.g., shipworms)	1	4.0	4.2.2.1.11/4-25
Aquatic Ecology (for plants with once-through and cooling pond heat dissipation systems)			
25. Entrainment of fish and shellfish in early life stages for plants with once-through and cooling pond heat dissipation systems	2	NA	Issue applies to a heat dissipation system, once-through cooling, that TMI-1 does not have.
26. Impingement of fish and shellfish for plants with once-through and cooling pond heat dissipation systems	2	NA	Issue applies to a heat dissipation system, once-through cooling, that TMI-1 does not have.
27. Heat shock for plants with once-through and cooling pond heat dissipation systems	2	NA	Issue applies to a heat dissipation system, once-through cooling, that TMI-1 does not have.
Aquatic Ecology (for plants with cooling-tower-based heat dissipation systems)			
28. Entrainment of fish and shellfish in early life stages for plants with cooling-tower-based heat dissipation systems	1	4.2	4.3.3/4-33
29. Impingement of fish and shellfish for plants with cooling-tower-based heat dissipation systems	1	4.3	4.3.3/4-33
30. Heat shock for plants with cooling-tower-based heat dissipation systems	1	4.4	4.3.3/4-33
Groundwater Use and Quality			
31. Impacts of refurbishment on groundwater use and quality	1	4.0	3.4.2/3-5

Table A-1. TMI-1 Environmental Report Discussion of License Renewal NEPA Issues[a] (continued)

Issue		Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
32.	Groundwater use conflicts (potable and service water; plants that use < 100 gpm)	1	NA	Issue applies to an activity, using < 100 gpm or more of groundwater, TMI-1 usage is > 100 gpm.
33.	Groundwater use conflicts (potable, service water, and dewatering; plants that use > 100 gpm)	2	4.5	4.8.1.1/4-115 and 4.8.1.2/4-117
34.	Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river)	2	4.6	4.8.1.3/4-117
35.	Groundwater use conflicts (Ranney wells)	2	NA	Issue applies to a plant feature, Ranney wells, which TMI-1 does not have.
36.	Groundwater quality degradation (Ranney wells)	1	NA	Issue applies to a feature, Ranney wells, which TMI-1 does not have.
37.	Groundwater quality degradation (saltwater intrusion)	1	NA	Issue applies to a feature, location at an ocean or estuary site, which TMI-1 does not have.
38.	Groundwater quality degradation (cooling ponds in salt marshes)	1	NA	Issue applies to a feature, location in a salt marsh, which TMI-1 does not have.
39.	Groundwater quality degradation (cooling ponds at inland sites)	2	NA	Issue applies to a feature, cooling ponds, which TMI-1 does not have.
Terrestrial Resources				
40.	Refurbishment impacts to terrestrial resources	2	4.9	3.6/3-6
41.	Cooling tower impacts on crops and ornamental vegetation	1	NA	Issue applies to a feature, mechanical draft cooling towers, which TMI-1 does not have.
42.	Cooling tower impacts on native plants	1	NA	Issue applies to a feature, mechanical draft cooling towers, which TMI-1 does not have.
43.	Bird collisions with cooling towers	1	4.0	4.3.5.2/4-45
44.	Cooling pond impacts on terrestrial resources	1	NA	Issue applies to a feature, cooling ponds, which TMI-1 does not have.

Table A-1. TMI-1 Environmental Report Discussion of License Renewal NEPA Issues[a] (continued)

Issue		Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
45.	Power line right-of-way management (cutting and herbicide application)	1	4.0	4.5.6.1/4-71
46.	Bird collisions with power lines	1	4.0	4.5.6.2/4-74
47.	Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)	1	4.0	4.5.6.3/4-77
48.	Floodplains and wetlands on power line right-of-way	1	4.0	4.5.7.7/4-81
Threatened or Endangered Species (for all plants)				
49.	Threatened or endangered species	2	4.10	Refurbishment 3.9/3-48 Renewal Term 4.1/4-1
Air Quality				
50.	Air quality during refurbishment (non-attainment and maintenance areas)	2	4.11	3.3/3-2
51.	Air quality effects of transmission lines	1	4.0	4.5.2/4-62
Land Use				
52.	Onsite land use	1	4.0	3.2/3-1
53.	Power line right-of-way land use impacts	1	4.0	4.5.3/4-62
Human Health				
54.	Radiation exposures to the public during refurbishment	1	4.0	3.8.1/3-27
55.	Occupational radiation exposures during refurbishment	1	4.0	3.8.2/3-42
56.	Microbiological organisms (occupational health)	1	4.0	4.3.6/4-48
57.	Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	2	4.12	4.3.6/4-48
58.	Noise	1	4.0	4.3.7/4-49
59.	Electromagnetic fields, acute effects	2	4.13	4.5.4.1/4-66
60.	Electromagnetic fields, chronic effects	NA	4.0	4.5.4.2/4-67

Table A-1. TMI-1 Environmental Report Discussion of License Renewal NEPA Issues[a] (continued)

Issue		Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
61.	Radiation exposures to public (license renewal term)	1	4.0	4.6.2/4-87
62.	Occupational radiation exposures (license renewal term)	1	4.0	4.6.3/4-95
		Socioeconomics		
63.	Housing impacts	2	4.14	Refurbishment 3.7.2/3-10 Renewal Term 4.7.1/4-101
64.	Public services: public safety, social services, and tourism and recreation	1	4.0	Refurbishment 3.7.4/3-14 (public service) 3.7.4.3/3-18 (safety) 3.7.4.4/3-19 (social) 3.7.4.6/3-20 (tour, rec.) Renewal Term 4.7.3/4-104 (public safety) 4.7.3.3/4-106 (safety) 4.7.3.44-107 (social) 4.7.3.6/4-107 (tour, rec.)
65.	Public services: public utilities	2	4.15	Refurbishment 3.7.4.5/3-19 Renewal Term 4.7.3/4-104
66.	Public services: education (refurbishment)	2	4.16	3.7.4.1/3-15
67.	Public services: education (license renewal term)	1	4.0 and 4.16.1	4.7.3.1/4-106
68.	Offsite land use (refurbishment)	2	4.17.1	3.7.5/3-20
69.	Offsite land use (license renewal term)	2	4.17.2	4.7.4/4-107
70.	Public services: transportation	2	4.18	Refurbishment 3.7.4.2/3-17 Renewal Term 4.7.3.2/4-106
71.	Historic and archaeological resources	2	4.19	Refurbishment 3.7.7/3-23 Renewal Term 4.7.7/4-114

Table A-1. TMI-1 Environmental Report Discussion of License Renewal NEPA Issues[a] (continued)

Issue		Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
72.	Aesthetic impacts (refurbishment)	1	4.0	3.7.8/3-24
73.	Aesthetic impacts (license renewal term)	1	4.0	4.7.6/4-111
74.	Aesthetic impacts of transmission lines (license renewal term)	1	4.0	4.5.8/4-83
	Postulated Accidents			
75.	Design basis accidents	1	4.0	5.3.2/5-11 (design basis) 5.5.1/5-114 (summary)
76.	Severe accidents	2	4.20	5.3.3/5-12 (probabilistic analysis) 5.3.3.2/5-19 (air dose) 5.3.3.3/5-49 (water) 5.3.3.4/5-65 (groundwater) 5.3.3.5/5-95 (economic) 5.4/5-106 (mitigation) 5.5.2/5-114 (summary)
	Uranium Fuel Cycle and Waste Management			
77.	Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high-level waste)	1	4.0	6.2/6-8
78.	Offsite radiological impacts (collective effects)	1	4.0	Not in GEIS.
79.	Offsite radiological impacts (spent fuel and high-level waste disposal)	1	4.0	Not in GEIS.
80.	Nonradiological impacts of the uranium fuel cycle	1	4.0	6.2.2.6/6-20 (land use) 6.2.2.7/6-20 (water use) 6.2.2.8/6-21 (fossil fuel) 6.2.2.9/6-21 (chemical)
81.	Low-level waste storage and disposal	1	4.0	6.4.2/6-36 (low-level def) 6.4.3/6-37 (low-level volume) 6.4.4/6-48 (renewal effects)
82.	Mixed waste storage and disposal	1	4.0	6.4.5/6-63
83.	Onsite spent fuel	1	4.0	6.4.6/6-70
84.	Nonradiological waste	1	4.0	6.5/6-86
85.	Transportation	1	4.0	6.3/6-31, as revised by Addendum 1, August 1999.

Table A-1. TMI-1 Environmental Report Discussion of License Renewal NEPA Issues[a] (continued)

Issue		Category	Section of this Environmental Report	GEIS Cross Reference[b] (Section/Page)
		Decommissioning		
86.	Radiation doses (decommissioning)	1	4.0	7.3.1/7-15
87.	Waste management (decommissioning)	1	4.0	7.3.2/7-19 (impacts) 7.4/7-25 (conclusions)
88.	Air quality (decommissioning)	1	4.0	7.3.3/7-21 (air) 7.4/7-25 (conclusions)
89.	Water quality (decommissioning)	1	4.0	7.3.4/7-21 (water) 7.4/7-25 (conclusions)
90.	Ecological resources (decommissioning)	1	4.0	7.3.5/7-21 (ecological) 7.4/7-25 (conclusions)
91.	Socioeconomic impacts (decommissioning)	1	4.0	7.3.7/7-19 (socioeconomic) 7.4/7-24 (conclusions)
		Environmental Justice		
92.	Environmental justice	NA	2.6.2	Not in GEIS.

a. Source: 10 CFR 51, Subpart A, Appendix A, Table B-1. (Issue numbers added to facilitate discussion.)
b. Source: Generic Environmental Impact Statement for License Renewal of Nuclear Plants (NUREG-1437).

Appendix B

Clean Water Act Documentation

Table of Contents

Letter	Page
Letter from L. McDonnell (Pennsylvania Department of Environmental Protection) to T. Dougherty (AmerGen) Re: AmerGen Energy Company –TMI NPDES Permit No. PA 0009920 (transmitting the renewed NPDES Permit, a Discharge Monitoring Report, and Supplemental Reporting Forms) October 30, 2007.	B-1
AmerGen Energy Company LLC TMI-1 Authorization to Discharge to the Susquehanna River under NPDES Permit No. PA0009920, dated October 30, 2007	B-3
Three Mile Island Nuclear Station Section 401 State Water Quality Certification Docket No. 77-076-B, dated November 9, 1977, issued by the Pennsylvania Department of Environmental Protection	B-57

Pennsylvania Department of Environmental Protection

909 Elmerton Avenue
Harrisburg, PA 17110-8200

OCT 3 0 2007

Southcentral Regional Office

717-705-4707
FAX - 717-705-4760

CERTIFIED MAIL NO. 7006 0100 0004 5235 2971

Mr. Thomas Dougherty, Plant Manager
AmerGen Energy Company, LLC
Route 441 South, PO Box 480
Middletown, PA 17057-0480

Re: Industrial Waste
AmerGen Energy Company - TMI
NPDES Permit No. PA 0009920
APS ID No. 9920
Authorization No. 676346
Londonderry Township, Dauphin County

Dear Mr. Dougherty:

Your permit is enclosed. Read the permit and the special conditions carefully.

A Discharge Monitoring Report (DMR) and Supplemental Reporting Forms are included. The master DMR will be prepared and distributed by the U.S. Environmental Protection Agency (EPA) in the near future. Use the enclosed DMR Form until you receive a master from EPA. The reporting forms must be submitted to the Department and the EPA Regional Office as instructed in the permit and the enclosed Instruction Sheet.

Any person aggrieved by this action may appeal, pursuant to Section 4 of the Environmental Hearing Board Act, 35 P.S. Section 7514, and the Administrative Agency Law, 2 Pa. C.S. Chapter 5A, to the Environmental Hearing Board, Second Floor, Rachel Carson State Office Building, 400 Market Street, PO Box 8457, Harrisburg, PA 17105-8457, 717-787-3483. TDD users may contact the Board through the Pennsylvania Relay Service, 800-654-5984. Appeals must be filed with the Environmental Hearing Board within 30 days of receipt of written notice of this action unless the appropriate statute provides a different time period. Copies of the appeal form and the Board's rules of practice and procedure may be obtained from the Board. The appeal form and the Board's rules of practice and procedure are also available in braille or on audiotape from the Secretary to the Board at 717-787-3483. This paragraph does not, in and of itself, create any right of appeal beyond that permitted by applicable statutes and decisional law.

IF YOU WANT TO CHALLENGE THIS ACTION, YOUR APPEAL MUST REACH THE BOARD WITHIN 30 DAYS. YOU DO NOT NEED A LAWYER TO FILE AN APPEAL WITH THE BOARD.

Mr. Thomas Dougherty - 2 -

IMPORTANT LEGAL RIGHTS ARE AT STAKE, HOWEVER, SO YOU SHOULD SHOW THIS DOCUMENT TO A LAWYER AT ONCE. IF YOU CANNOT AFFORD A LAWYER, YOU MAY QUALIFY FOR FREE PRO BONO REPRESENTATION. CALL THE SECRETARY TO THE BOARD (717-787-3483) FOR MORE INFORMATION.

If you have any questions, please call Mr. James D. Miller of the Permits Section at 717-705-4825.

Sincerely,

Lee A. McDonnell, P.E.
Program Manager
Water Management Program

Enclosures

cc: U.S. Environmental Protection Agency (w/NPDES)
Scott Cogley, AmerGen Energy Company, LLC (w/enclosure)

Pennsylvania Department of Environmental Protection

WATER MANAGEMENT PROGRAM

AUTHORIZATION TO DISCHARGE UNDER THE
NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM
NPDES PERMIT NO. PA 0009920

In compliance with the provisions of the Clean Water Act, 33 U.S.C. Section 1251 et seq. (the "Act") and Pennsylvania's Clean Streams Law, as amended, 35 P.S. Section 691.1 et seq.,

AMERGEN ENERGY COMPANY, LLC
(THREE MILE ISLAND NUCLEAR STATION)
ROUTE 441 SOUTH, PO BOX 480
MIDDLETOWN, PA 17057-0480

is hereby authorized to discharge from a facility located in Londonderry Township, Dauphin County to the receiving waters named Susquehanna River in Watershed 7-G in accordance with effluent limitations, monitoring requirements and other conditions set forth in Parts A, B, and C hereof.

THIS PERMIT SHALL BECOME EFFECTIVE ON NOVEMBER 1, 2007

AND EXPIRE AT MIDNIGHT, OCTOBER 31, 2012.

The authority granted by this permit is subject to the following further qualifications:

1. If there is a conflict between the application, its supporting documents and/or amendments and the terms and conditions of this permit, the terms and conditions shall apply.
2. Failure to comply with the terms or conditions of this permit is grounds for enforcement action; for permit termination, revocation and reissuance or modification; or for denial of a permit renewal application.
3. Application for renewal of this permit, or notification of intent to cease discharging by the expiration date, must be submitted to the Department at least 180 days prior to the above expiration date (unless permission has been granted by the Department for submission at a later date), using the appropriate NPDES Permit Application Form. In the event that a timely and complete application for renewal has been submitted and the Department is unable, through no fault of the permittee, to reissue the permit before the above expiration date, the terms and conditions to this permit will be automatically continued and will remain fully effective and enforceable pending the grant or denial of the application for permit renewal.
4. This permit does not constitute authorization to construct or make modifications to wastewater treatment facilities necessary to meet the terms and conditions of this permit.

PERMIT ISSUED: OCT 3 0 2007

BY: Lee A. McDonnell

Lee A. McDonnell, P.E.
Program Manager
Southcentral Regional Office

PERMIT AMENDED: ____________

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NPDES Permit No. PA 0009920
Page 2

PART A

LAT: 40°09'08"
LONG: 76°43'40"

I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. Outfall 001, which receives wastewater from circulating cooling water; secondary service water; reactor building emergency cooling; decay heat; nuclear service water; liquid radioactive waste treatment; contributing internal monitoring points (101, 401, 501, 701); station blackout diesel cooling water; and other minor sources as identified in the NPDES permit application.

1. Numbers in parentheses ( ) refer to Footnotes/Additional Requirements/Information on page 3.

2. Samples taken in compliance with the monitoring requirements shall be taken at the following location(s): at Outfall 001, unless otherwise noted below.

DISCHARGE LIMITATIONS(1)						MONITORING REQUIREMENTS	
	Mass Units (lbs/day)		Concentrations (mg/l)(3)			(4)	
Discharge(2) Parameter	Average Monthly	Maximum Daily	Average Monthly	Maximum Daily	Inst. Maximum	Monitoring Frequency	Sample Type
Flow (mgd)	Monitor & Report	Monitor & Report	XXX	XXX	XXX	Continuous	Recorded
pH (S.U.)	From 6.0 to 9.0 inclusive					2/month	Grab
Total Suspended Solids	XXX	XXX	Monitor & Report	Monitor & Report	XXX	2/month	Grab
Temperature (10/1-3/31)	XXX	XXX	XXX	110° F	XXX	Continuous	Recorded
Temperature (4/1-9/30)	XXX	XXX	XXX	115° F	XXX	Continuous	Recorded
Free Available Chlorine	XXX	XXX	XXX	0.2	0.5	(9)	(9)
Total Residual Oxidants (TRO)(8)(10)	XXX	XXX	XXX	0.14	0.17	(6)	(6)
Spectrus CT 1300(8)	XXX	XXX	XXX	0.1	0.3	(5)	(5)
Hydrazine	XXX	XXX	XXX	XXX	Not Detectable	(7)	(7)

NPDES Permit No. PA 0009920
Page 3

PART A

B. Footnotes/Additional Requirements/Information

1. The discharge limitations for Outfall 001 were determined using a maximum design effluent discharge rate of 81.02 million gallons per day.

2. In addition to the listed parameters, the discharge of floating solids, visible foam, or other substances which produce color, tastes, odors, turbidity or settle to form deposits shall be controlled.

3. The instantaneous maximum discharge limitations are for compliance use by the Department only. Do not report instantaneous maximums on Discharge Monitoring Reports unless specifically required on those forms to do so.

4. This is the minimum number of sampling events required. Permittees are encouraged, and it may be advantageous in demonstrating compliance, to perform more than the minimum number of sampling events.

5. Once per week grab sample during chemical addition.

6. Once per week grab sample during chemical addition. Samples shall be taken at Outfall 001. The permittee has the option to perform sampling at the TMI Unit 1 MDCT discharge when Outfall 001 is inaccessible due to inclement weather or when there are personnel safety concerns.

7. Hydrazine shall be analyzed during the discharges due to lay-up of TMI-1 once-through steam generators following plant outages. Samples shall be taken once per week during steam generator drain-down. The testing procedure shall be ASTM-D1385-88 (reapproved 1991).

8. If the concentration of biocide within a closed system is determined by analysis to be less than or equal to the corresponding effluent limitation, then sampling at Outfall 001 will not be required once the system blowdown is released.

9. Once per week grab sample during chemical addition. Free available chlorine limitations and monitoring are applicable only when chlorine compounds (where chlorine is the sole active ingredient) are added to the Circulating Water System or the River Water System. Monitoring may be conducted at the TMI-1 MDCT basin if Outfall 001 is not available.

10. The Total Residual Oxidants (TRO) effluent limitation is applicable when both Sodium Bromide and Sodium Hypochlorite are being used together for biological growth control.

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PART A

Internal Monitoring Point

I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. Outfall 101, which receives wastewater from the sewage treatment plant.

1. Numbers in parentheses ( ) refer to Footnotes/Additional Requirements/Information below.

2. Samples taken in compliance with the monitoring requirements shall be taken at the following location(s): at discharge from sewage treatment plant.

Discharge(2) Parameter	DISCHARGE LIMITATIONS(1)					MONITORING (6) REQUIREMENTS	
	Mass Units (lbs/day)		Concentrations (mg/l)(3)			(4)	
	Average Monthly	Maximum Daily	Average Monthly	Maximum Daily	Inst. Maximum	Monitoring Frequency	Sample Type
Flow (mgd)	Monitor & Report	Monitor & Report	XXX	XXX	XXX	Continuous	Recorded
Total Suspended Solids	XXX	XXX	30	XXX	60	1/quarter	8-hour Comp
$CBOD_5$	XXX	XXX	25	XXX	50	1/quarter	8-hour Comp
Phosphorus (as P)	XXX	XXX	2.0	XXX	4.0	1/quarter	8-hour Comp
Fecal Coliform (5/1-9/30) (5)	XXX	XXX	200/100 ml	XXX	XXX	1/quarter	Grab
Fecal Coliform (10/1-4/30) (5)	XXX	XXX	2,000/100 ml	XXX	XXX	1/quarter	Grab

B. Footnotes/Additional Requirements/Information

1. The discharge limitations for Outfall 101 were determined using an effluent discharge rate of 0.08 million gallons per day.

2. In addition to the listed parameters, the discharge of floating solids, visible foam, or other substances which produce color, tastes, odors, turbidity or settle to form deposits shall be controlled.

3. The instantaneous maximum discharge limitations are for compliance use by the Department only. Do not report instantaneous maximums on Discharge Monitoring Reports unless specifically required on those forms to do so.

4. This is the minimum number of sampling events required. Permittees are encouraged, and it may be advantageous in demonstrating compliance, to perform more than the minimum number of sampling events.

5. The permittee shall provide for effective disinfection of this discharge to control disease-producing organisms during the swimming season (May 1 through September 30) to achieve a fecal coliform concentration not greater than 200/100 ml as a geometric average, and not greater than 1,000/100 ml in more than 10 percent of the samples tested. During the period of October 1 through April 30 the fecal coliform concentration shall not exceed 2,000/100 ml as a geometric average.

6. To remain eligible for monitoring reductions, the permittee may not have any significant noncompliance violations for effluent limitations of the parameters for which reductions have been granted, or failure to submit DMRs, or may not be subject to a new formal enforcement action. If any of the above occurs, the permit will be reopened and amended to reflect the previous monitoring frequencies.

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PART A

Internal Monitoring Point

I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. Outfall 401, which receives wastewater from the Industrial Waste Filter System.

1. Numbers in parentheses ( ) refer to Footnotes/Additional Requirements/Information below.

2. Samples taken in compliance with the monitoring requirements shall be taken at the following location(s): at discharge from Industrial Waste Filter System.

DISCHARGE LIMITATIONS(1)						MONITORING (5) REQUIREMENTS	
	Mass Units (lbs/day)		Concentrations (mg/l)(3)			(4)	
Discharge(2) Parameter	Average Monthly	Maximum Daily	Average Monthly	Maximum Daily	Inst. Maximum	Monitoring Frequency	Sample Type
Flow (mgd)	Monitor & Report	Monitor & Report	XXX	XXX	XXX	Continuous	Recorded
pH (S.U.)	From 6.0 to 9.0 inclusive					1/quarter	Grab
Total Suspended Solids	XXX	XXX	30	100	XXX	1/quarter	Grab
Oil and Grease	XXX	XXX	15	20	30	1/quarter	Grab

B. Footnotes/Additional Requirements/Information

1. The discharge limitations for Outfall 401 were determined using an effluent discharge rate of 0.3 million gallons per day.

2. In addition to the listed parameters, the discharge of floating solids, visible foam, or other substances which produce color, tastes, odors, turbidity or settle to form deposits shall be controlled.

3. The instantaneous maximum discharge limitations are for compliance use by the Department only. Do not report instantaneous maximums on Discharge Monitoring Reports unless specifically required on those forms to do so.

4. This is the minimum number of sampling events required. Permittees are encouraged, and it may be advantageous in demonstrating compliance, to perform more than the minimum number of sampling events.

5. To remain eligible for monitoring reductions, the permittee may not have any significant noncompliance violations for effluent limitations of the parameters for which reductions have been granted, or failure to submit DMRs, or may not be subject to a new formal enforcement action. If any of the above occurs, the permit will be reopened and amended to reflect the previous monitoring frequencies.

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PART A

Internal Monitoring Point

I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. Outfall 501, which receives wastewater from Unit 1 Secondary Neutralizer Tank.

1. Numbers in parentheses ( ) refer to Footnotes/Additional Requirements/Information below.
2. Samples taken in compliance with the monitoring requirements shall be taken at the following location(s): at discharge from Unit 1 Secondary Neutralizer Tank or from the mixed tank prior to release.

	DISCHARGE LIMITATIONS(1)					MONITORING (5) REQUIREMENTS	
	Mass Units (lbs/day)		Concentrations (mg/l)(3)			(4)	
Discharge(2) Parameter	Average Monthly	Maximum Daily	Average Monthly	Maximum Daily	Inst. Maximum	Monitoring Frequency	Sample Type
Flow (mgd)	Monitor & Report	Monitor & Report	XXX	XXX	XXX	2/month	Calculated
pH (S.U.)	From 6.0 to 9.0 inclusive					2/month	Grab
Total Suspended Solids	XXX	XXX	30	100	XXX	2/month	Grab
Oil and Grease	XXX	XXX	15	20	30	1/quarter	Grab

B. Footnotes/Additional Requirements/Information

1. The discharge limitations for Outfall 501 were determined using an effluent discharge rate of 0.3 million gallons per day.
2. In addition to the listed parameters, the discharge of floating solids, visible foam, or other substances which produce color, tastes, odors, turbidity or settle to form deposits shall be controlled.
3. The instantaneous maximum discharge limitations are for compliance use by the Department only. Do not report instantaneous maximums on Discharge Monitoring Reports unless specifically required on those forms to do so.
4. This is the minimum number of sampling events required. Permittees are encouraged, and it may be advantageous in demonstrating compliance, to perform more than the minimum number of sampling events.
5. To remain eligible for monitoring reductions, the permittee may not have any significant noncompliance violations for effluent limitations of the parameters for which reductions have been granted, or failure to submit DMRs, or may not be subject to a new formal enforcement action. If any of the above occurs, the permit will be reopened and amended to reflect the previous monitoring frequencies.

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PART A

Internal Monitoring Point

I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. Outfall 701, which receives wastewater from the Industrial Waste Treatment System.

1. Numbers in parentheses ( ) refer to Footnotes/Additional Requirements/Information below.
2. Samples taken in compliance with the monitoring requirements shall be taken at the following location(s): at discharge from the Industrial Waste Treatment System.

DISCHARGE LIMITATIONS(1)						MONITORING (5) REQUIREMENTS	
	Mass Units (lbs/day)		Concentrations (mg/l)(3)			(4)	
Discharge(2) Parameter	Average Monthly	Maximum Daily	Average Monthly	Maximum Daily	Inst. Maximum	Monitoring Frequency	Sample Type
Flow (mgd)	Monitor & Report	Monitor & Report	XXX	XXX	XXX	Continuous	Recorded
pH (S.U.)	From 6.0 to 9.0 inclusive					2/month	Grab
Total Suspended Solids	XXX	XXX	30	100	XXX	2/month	Grab
Oil and Grease	XXX	XXX	15	20	30	1/quarter	Grab

B. Footnotes/Additional Requirements/Information

1. The discharge limitations for Outfall 701 were determined using an effluent discharge rate of 0.3 million gallons per day.
2. In addition to the listed parameters, the discharge of floating solids, visible foam, or other substances which produce color, tastes, odors, turbidity or settle to form deposits shall be controlled.
3. The instantaneous maximum discharge limitations are for compliance use by the Department only. Do not report instantaneous maximums on Discharge Monitoring Reports unless specifically required on those forms to do so.
4. This is the minimum number of sampling events required. Permittees are encouraged, and it may be advantageous in demonstrating compliance, to perform more than the minimum number of sampling events.
5. To remain eligible for monitoring reductions, the permittee may not have any significant noncompliance violations for effluent limitations of the parameters for which reductions have been granted, or failure to submit DMRs, or may not be subject to a new formal enforcement action. If any of the above occurs, the permit will be reopened and amended to reflect the previous monitoring frequencies.

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PART A

LAT: 40°09'10"
LONG: 76°43'40"

I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. Outfall 003, emergency discharge from Unit 1, in the event Outfall 001 becomes blocked.

1. Numbers in parentheses ( ) refer to Footnotes/Additional Requirements/Information on page 9.

2. Samples taken in compliance with the monitoring requirements shall be taken at the following location(s): at Outfall 003, unless otherwise noted below.

DISCHARGE LIMITATIONS(1)						MONITORING (5) REQUIREMENTS	
	Mass Units (lbs/day)		Concentrations (mg/l)(3)			(4)	
Discharge(2) Parameter	Average Monthly	Maximum Daily	Average Monthly	Maximum Daily	Inst. Maximum	Monitoring Frequency	Sample Type
Flow (mgd)	Monitor & Report	Monitor & Report	XXX	XXX	XXX	1/day	Estimated
pH (S.U.)	From 6.0 to 9.0 inclusive					2/month	Grab
Total Suspended Solids	XXX	XXX	Monitor & Report	Monitor & Report	XXX	2/month	Grab
Temperature (10/1-3/31)	XXX	XXX	XXX	110° F	XXX	1/shift	i-s
Temperature (4/1-9/30)	XXX	XXX	XXX	115° F	XXX	1/shift	i-s
Free Available Chlorine	XXX	XXX	XXX	0.2	0.5	(10)	(10)
Total Residual Oxidants (TRO)(9)(11)	XXX	XXX	XXX	0.14	0.17	(7)	(7)
Spectrus CT 1300(9)	XXX	XXX	XXX	0.1	0.3	(6)	(6)
Hydrazine	XXX	XXX	XXX	XXX	Not Detectable	(8)	(8)

PART A

B. Footnotes/Additional Requirements/Information

1. The discharge limitations for Outfall 003 were determined using a maximum design effluent discharge rate of 81.02 million gallons per day.

2. In addition to the listed parameters, the discharge of floating solids, visible foam, or other substances which produce color, tastes, odors, turbidity or settle to form deposits shall be controlled.

3. The instantaneous maximum discharge limitations are for compliance use by the Department only. Do not report instantaneous maximums on Discharge Monitoring Reports unless specifically required on those forms to do so.

4. This is the minimum number of sampling events required. Permittees are encouraged, and it may be advantageous in demonstrating compliance, to perform more than the minimum number of sampling events.

5. Only when discharging.

6. Once per week grab sample during chemical addition.

7. Once per week grab sample during chemical addition. Samples shall be taken at Outfall 003. The permittee has the option to perform sampling at the TMI Unit 1 MDCT basin if Outfall 003 is inaccessible due to inclement weather or when there are personnel safety concerns.

8. Hydrazine shall be analyzed during the discharges due to lay-up of TMI-1 once-through steam generators following plant outages. Samples shall be taken once per week during steam generator drain-down. The testing procedure shall be ASTM-D1385-88 (reapproved 1991).

9. If the concentration of biocide within a closed system is determined by analysis to be less than or equal to the corresponding effluent limitation, then sampling at Outfall 003 will not be required once the system blowdown is released.

10. Once per week grab sample during chemical addition. Free available chlorine limitations and monitoring are applicable only when chlorine compounds (where chlorine is the sole active ingredient) are added to the Circulating Water System or the River Water System. Monitoring may be conducted at the TMI-1 MDCT basin if Outfall 003 is not available.

11. The Total Residual Oxidants (TRO) effluent limitation is applicable when both Sodium Bromide and Sodium Hypochlorite are being used together for biological growth control.

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PART A

LAT: 40°09'10"
LONG: 76°43'18"

I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. Outfall 004, emergency discharge from Unit 1, in the event Unit 1 Mechanical Draft Cooling Tower becomes blocked.

1. Numbers in parentheses ( ) refer to Footnotes/Additional Requirements/Information on page 11.

2. Samples taken in compliance with the monitoring requirements shall be taken at the following location(s): at outfall 004.

DISCHARGE LIMITATIONS(1)						MONITORING (5) REQUIREMENTS	
	Mass Units (lbs/day)		Concentrations (mg/l)(3)			(4)	
Discharge(2) Parameter	Average Monthly	Maximum Daily	Average Monthly	Maximum Daily	Inst. Maximum	Monitoring Frequency	Sample Type
Flow (mgd)	Monitor & Report	Monitor & Report	XXX	XXX	XXX	1/day	Estimated
pH (S.U.)	From 6.0 to 9.0 inclusive					2/month	Grab
Total Suspended Solids	XXX	XXX	Monitor & Report	Monitor & Report	XXX	2/month	Grab
Temperature	XXX	XXX	XXX	Monitor & Report	XXX	1/shift	i-s
Free Available Chlorine	XXX	XXX	XXX	0.2	0.5	(9)	(9)
Total Residual Oxidants (TRO)(8)(10)	XXX	XXX	XXX	0.14	0.17	(6)	(6)
Spectrus CT 1300 (8)	XXX	XXX	XXX	0.1	0.3	(6)	(6)
Hydrazine	XXX	XXX	XXX	XXX	Not Detectable	(7)	(7)

PART A

B. Footnotes/Additional Requirements/Information

1. The discharge limitations for Outfall 004 were determined using a maximum design effluent discharge rate of 81.02 million gallons per day.

2. In addition to the listed parameters, the discharge of floating solids, visible foam, or other substances which produce color, tastes, odors, turbidity or settle to form deposits shall be controlled.

3. The instantaneous maximum discharge limitations are for compliance use by the Department only. Do not report instantaneous maximums on Discharge Monitoring Reports unless specifically required on those forms to do so.

4. This is the minimum number of sampling events required. Permittees are encouraged, and it may be advantageous in demonstrating compliance, to perform more than the minimum number of sampling events.

5. Only when discharging.

6. Once per week grab sample during chemical addition.

7. Hydrazine shall be analyzed during the discharges due to lay-up of TMI-1 once-through steam generators following plant outages. Samples shall be taken once per week during steam generator drain-down. The testing procedure shall be ASTM-D1385-88 (reapproved 1991).

8. If the concentration of biocide within a closed system is determined by analysis to be less than or equal to the corresponding effluent limitation, then sampling at Outfall 004 will not be required once the system blowdown is released.

9. Once per week grab sample during chemical addition. Free available chlorine limitations and monitoring are applicable only when chlorine compounds (where chlorine is the sole active ingredient) are added to the Circulating Water System or the River Water System.

10. The Total Residual Oxidants (TRO) effluent limitation is applicable when both Sodium Bromide and Sodium Hypochlorite are being used together for biological growth control.

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PART A

LAT: 40°09'06"
LONG: 76°43'18"

I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. Outfall 005B, which receives wastewater from screen house desilting; dewatering of Unit 1 Natural Draft Cooling Towers; fire brigade training; fuel oil off-loading station; industrial cooler maintenance; emergency diesel generator building floor drains; and operation of the east dike settling basin drain valve.

1. Numbers in parentheses ( ) refer to Footnotes/Additional Requirements/Information below.

2. Samples taken in compliance with the monitoring requirements shall be taken at the following location(s): at Outfall 005B.

DISCHARGE LIMITATIONS						MONITORING REQUIREMENTS	
	Mass Units (lbs/day)		Concentrations (mg/l)(2)			(3)	
Discharge(1) Parameter	Average Monthly	Maximum Daily	Average Monthly	Maximum Daily	Inst. Maximum	Monitoring Frequency	Sample Type
Flow (mgd)	Monitor & Report	Monitor & Report	XXX	XXX	XXX	1/month	Estimated
pH (S.U.)	From 6.0 to 9.0 inclusive					2/month	Grab
Total Suspended Solids	XXX	XXX	30	100	XXX	2/month	Grab
Oil and Grease	XXX	XXX	15	20	30	2/month	Grab

B. Footnotes/Additional Requirements/Information

1. In addition to the listed parameters, the discharge of floating solids, visible foam, or other substances which produce color, tastes, odors, turbidity or settle to form deposits shall be controlled.

2. The instantaneous maximum discharge limitations are for compliance use by the Department only. Do not report instantaneous maximums on Discharge Monitoring Reports unless specifically required on those forms to do so.

3. This is the minimum number of sampling events required. Permittees are encouraged, and it may be advantageous in demonstrating compliance, to perform more than the minimum number of sampling events.

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PART A

LAT: 40°09'16"
LONG: 76°43'41"

I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. Outfall 006, which receives wastewater from intake screen wash and sluice water; the intake pump strainer backwash; and the intake chlorinator building floor drain.

DISCHARGE LIMITATIONS						MONITORING REQUIREMENTS	
	Mass Units (lbs/day)		Concentrations (mg/l)				
Discharge Parameter	Average Monthly	Maximum Daily	Average Monthly	Maximum Daily	Inst. Maximum	Monitoring Frequency	Sample Type
	No discharge limitations are necessary. All debris collected on the intake screens shall be collected and not discharged back to the river.						

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PART A

B. Monitoring Requirements for Stormwater Outfalls 005A, SO1, SO2, SO3, SO4 [(1)]

	MONITORING REQUIREMENTS	
Parameter	Grab Sample (mg/l)	Monitor Frequency [(2)]
5-day CBOD	Monitor & Report	1/year
Chemical Oxygen Demand	Monitor & Report	1/year
Total Suspended Solids	Monitor & Report	1/year
Total Phosphorus	Monitor & Report	1/year
Total Kjeldahl Nitrogen	Monitor & Report	1/year
Dissolved Iron	Monitor & Report	1/year
Oil and Grease	Monitor & Report	1/year
pH (S.U.)	Monitor & Report	1/year

Supplemental Footnotes:

(1) See PART C - "REQUIREMENTS APPLICABLE TO STORMWATER OUTFALLS" for further conditions and instructions.

(2) An annual inspection may be performed in lieu of monitoring. Detailed records shall be made and kept available on the site at all times.

PART A

II. DEFINITIONS

A. "Bypass" means the intentional diversion of waste streams from any portion of a treatment facility.

B. "Severe property damage" means substantial physical damage to property, damage to the treatment facilities that causes them to become inoperable, or substantial and permanent loss of natural resources that 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.

C. "Daily discharge" means the discharge of a pollutant measured during a calendar day or any 24-hour period that reasonably represents the calendar day for purposes of sampling. For pollutants with limitations expressed in units of mass, the "daily discharge" is calculated as the total mass of the pollutant discharged over the day. For pollutants with limitations expressed in other units of measurement, the "daily discharge" is calculated as the average measurement of the pollutant over the day.

D. "Average" refers to the use of an arithmetic mean, unless otherwise specified in this permit.

E. "Geometric Average (mean)" means the average of a set of n sample results given by the nth root of their product.

F. "Average monthly" discharge limitation means the highest allowable average of "daily discharge" over a calendar month, calculated as the sum of all "daily discharge" measured during a calendar month divided by the number of "daily discharge" measured during that month.

G. "Average weekly" discharge limitation means the highest allowable average of "daily discharge" over a calendar week, calculated as the sum of all "daily discharge" measured during a calendar week divided by the number of "daily discharge" measured during that week.

H. "Maximum daily" discharge limitation means the highest allowable "daily discharge."

I. "Maximum any time (instantaneous maximum)" means the level not to be exceeded at any time in any grab sample.

J. "Composite Sample" (for all except GC/MS volatile organic analysis) means a combination of individual samples (at least eight for a 24-hour period or four for an 8-hour period) of at least 100 milliliters each obtained at spaced time intervals during the compositing period. The composite must be "flow-proportional", which means either the volume of each individual sample is proportional to discharge flow rates, or the sampling interval is proportional to the flow rates over the time period used to produce the composite.

"Composite Sample for GC/MS volatile organic analysis" consists of at least four aliquots or grab samples collected during the sampling event (not necessarily flow proportioned). The samples must be combined in the laboratory immediately before analysis and then one analysis is performed.

K. "Grab Sample" means an individual sample of at least 100 milliliters collected at a randomly selected time over a period not to exceed 15 minutes.

L. "i-s" means immersion stabilization - in which a calibrated device is immersed in the wastewater until the reading is stabilized.

PART A

M. The "Daily Average" temperature means the average of all temperature measurements made, or the mean value plot of the record of a continuous automated temperature recording instrument, either during a calendar day or during the operating day if flows are of a shorter duration.

N. "Measured Flow" means any method of liquid volume measurement, the accuracy of which has been previously demonstrated in engineering practice, or for which a relationship to absolute volume has been obtained.

O. "At outfall XXX" means a sampling location in outfall line XXX below the last point at which wastes are added to outfall line XXX, or where otherwise specified.

P. "Estimate" means to be based on a technical evaluation of the sources contributing to the discharge including, but not limited to, pump capabilities, water meters, and batch discharge volumes.

Q. "Noncontact cooling water" means water used to reduce temperature which does not come in direct contact with any raw material, intermediate product, waste product (other than heat), or finished product.

R. "Toxic Pollutant" means any pollutant listed as toxic under Section 307(a)(l) of the Clean Water Act.

S. "Hazardous substance" means any substance designated under 40 CFR Part 116 pursuant to Section 311 of the Clean Water Act.

T. "Publicly Owned Treatment Works (POTW)" means a facility, as defined by Section 212 of the Clean Water Act, which is owned by a State or Municipality, as defined by Section 502(4) of the Clean Water Act, including any sewers that convey wastewater to such a treatment works, but not including pipes, sewers or other conveyances not connected to a facility providing treatment. The term also means the municipality, as defined in Section 502(4) of the Clean Water Act, which has jurisdiction over the indirect discharges to and the discharges from such a treatment works.

U. "Industrial User" means an establishment that discharges or introduces industrial wastes into a Publicly Owned Treatment Works (POTW).

V. "Total Dissolved Solids" means the total dissolved (filterable) solids as determined by use of the method specified in 40 CFR Part 136.

W. "Stormwater associated with industrial activity" means the discharge from any conveyance which is used for collecting and conveying stormwater and which is directly related to manufacturing, processing, or raw materials storage areas as defined at 40 CFR Part 122.26(b)(14).

X. "Stormwater" means stormwater runoff, snowmelt runoff, and surface runoff and drainage.

Y. "Best Management Practices (BMPs)" means schedules of activities, prohibitions of practices, maintenance procedures, and other management practices to prevent or reduce the pollution of "waters of the United States." BMPs also include treatment requirements, operating procedures, and practices to control plant site runoff, spillage or leaks, sludge or waste disposal, or drainage from raw material storage.

PART A

III. SELF-MONITORING, REPORTING, AND RECORDS KEEPING

A. Representative Sampling

1. Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity.

2. Records Retention

   Except for records of monitoring information required by this permit related to the permittee's sludge use and disposal activities which shall be retained for a period of at least five years, all records of monitoring activities and results (including all original strip chart recordings for continuous monitoring instrumentation and calibration and maintenance records), copies of all reports required by this permit, and records of all data used to complete the application for this permit shall be retained by the permittee for three years from the date of the sample measurement, report, or application. The three-year period shall be extended as requested by the Department or the EPA Regional Administrator.

3. 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 or measurements.

   b. The person(s) who performed the sampling or measurements.

   c. The date(s) the analyses were performed.

   d. The person(s) who performed the analyses.

   e. The analytical techniques or methods used; and the associated detection level.

   f. The results of such analyses.

4. Test Procedures

   Facilities that test or analyze environmental samples used to demonstrate compliance with this permit shall be in compliance with laboratory accreditation requirements of Act 90 of 2002 (27 PA. C.S. §§ 4101-4113) relating to environmental laboratory accreditation.

   Unless otherwise specified in this permit, the test procedures for the analysis of pollutants shall be those contained in 40 CFR Part 136 (or in the case of sludge use or disposal, approved under 40 CFR Part 136, unless otherwise specified in 40 CFR Part 503), or alternate test procedures approved pursuant to those parts, unless other test procedures have been specified in the permit.

5. Quality/Assurance/Control

   In an effort to assure accurate self-monitoring analyses results:

   a. Permittee or its designated laboratory shall participate in the periodic scheduled quality assurance inspections conducted by the Department and the Environmental Protection Agency.

PART A

b. The permittee, or its designated laboratory, shall develop and implement a program to assure the quality and accurateness of the analyses performed to satisfy the requirements of this permit, in accordance with 40 CFR Part 136.

B. Reporting of Monitoring Results

1. The permittee shall effectively monitor the operation and efficiency of all wastewater treatment and control facilities, and the quantity and quality of the discharge(s) as specified in this permit.

2. Unless instructed otherwise in PART C of this permit, a properly completed DMR must be submitted to the following address within 28 days after the end of each monthly report period:

   Department of Environmental Protection
   Water Management Program
   Southcentral Regional Office
   909 Elmerton Avenue
   Harrisburg, PA 17110-8200

3. The completed DMR Form shall be signed and certified either by the following applicable person, as defined in 40 CFR Part 122.22(a), or by that person's duly authorized representative, as defined in 40 CFR Part 122.22(b):

   - For a corporation - by a responsible corporate officer.

   - For a partnership or sole proprietorship - by a general partner or the proprietor, respectively.

   - For a municipality, state, federal or other public agency - by a principle executive officer or ranking elected official.

   If signed by other than the above, written notification of delegation of DMR signatory authority must be submitted to the Department in advance of or along with the relevant DMR form.

4. If the permittee monitors any pollutant, using analytical methods described in PART A III.A.4 herein, more frequently than the permit requires, the results of this monitoring shall be incorporated, as appropriate, into the calculations used to report self-monitoring data on the DMR.

C. Reporting Requirements

1. Planned Changes - The permittee shall give notice to the Department 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 could significantly change the nature or increase the quantity of pollutants discharged. This notification applies to pollutants that are not subject to either the effluent limitations in the permit, or the toxic substance notification requirements of PART A III.D herein.

PART A

b. The alteration or addition results in a significant change in the permittee's sludge use or disposal practices, and such alteration, addition, or change may justify the application of permit conditions that are different from or absent in the existing permit, including notification of additional use or disposal sites not reported during the permit application process or not reported pursuant to an approved land application plan.

c. 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 Part 122.29(b).

2. Anticipated Noncompliance

The permittee shall give advance notice to the Department of any planned changes in the permitted facility or activity that may result in noncompliance with permit requirements.

3. Unanticipated Noncompliance or Potential Pollution Reporting

a. The permittee shall report any noncompliance or incidents causing or threatening pollution pursuant to 25 Pa. Code § 91.33 immediately, if possible, but in no case later than 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance.

b. The following shall be included as information that must be reported within 24 hours under this paragraph:

(1) Any unanticipated bypass that exceeds any effluent limitation in the permit.

(2) Any upset which exceeds or has the potential to exceed any effluent limitation in the permit.

(3) Violation of a maximum daily discharge limitation for any of the pollutants listed in the permit.

c. The Department may waive the written report on a case-by-case basis for reports under paragraph C.3.a of this section if the oral report has been received within 24 hours.

4. Other Noncompliance

The permittee shall report all instances of noncompliance not reported under paragraph C.3 of this section, at the time DMRs are submitted. The reports shall contain the information listed in paragraph C.3 of this section.

5. Other Information

Where the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application or in any report to the Department, it shall promptly submit the correct and complete facts or information.

PART A

D. Specific Toxic Pollutant Notification Levels (for Manufacturing, Commercial, Mining, and Silvicultural Direct Dischargers) - The permittee shall notify the Department as soon as it knows or has reason to believe the following:

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

   a. One hundred micrograms per liter.

   b. Two hundred micrograms per liter for acrolein and acrylonitrile.

   c. Five hundred micrograms per liter for 2,4-dinitrophenol and 2-methyl-4,6-dinitrophenol.

   d. One milligram per liter for antimony.

   e. Five times the maximum concentration value reported for that pollutant in the permit application.

   f. Any other notification level established by the Department.

2. That any activity has occurred or will occur which would result in any discharge, on a nonroutine 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.

   b. One milligram per liter for antimony.

   c. Ten times the maximum concentration value reported for that pollutant in the permit application.

   d. Any other notification level established by the Department.

PART B

I. MANAGEMENT REQUIREMENTS

A. Compliance Schedules

1. The permittee shall achieve compliance with the terms and conditions of this permit within the time frames specified in this permit.

2. The permittee shall submit reports of compliance or noncompliance, or progress reports as applicable, for any interim and final requirements contained in this permit. Such reports shall be submitted no later than 14 days following the applicable schedule date or compliance deadline.

B. Permit Modification, Termination, or Revocation and Reissuance

1. This permit may be modified, terminated, or revoked and reissued during its term in accordance with 25 Pa. Code Chapter 92.

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

3. In the absence of a Departmental action to modify or revoke and reissue this permit, the permittee shall comply with effluent standards or prohibitions established under Section 307(a) of the Clean Water Act for toxic pollutants within the time specified in the regulations that establish those standards or prohibitions.

C. Duty to Provide Information

1. The permittee shall furnish to the Department, within a reasonable time, any information which the Department may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit.

2. The permittee shall furnish to the Department, upon request, copies of records required to be kept by this permit.

3. Where the permittee is a Publicly Owned Treatment Works (POTW), the permittee shall provide the following information in the POTW's annual Wasteload Management Report, required under the provisions of 25 Pa. Code Chapter 94.

   a. Any new introduction of pollutants into the POTW from an Industrial User which would be subject to Sections 301 and 306 of the Clean Water Act if it were otherwise discharging directly into waters of the United States.

   b. Any substantial change in the volume or character of pollutants being introduced into the POTW by an Industrial User that was discharging into the POTW at the time of issuance of this permit.

   c. Any interference, pass-through, upsets, or permit violations that may be attributed to an Industrial User and actions taken to alleviate such events.

PART B

d. The identity of Significant Industrial Users served by the POTW which are subject to pretreatment standards adopted under Section 307(b) of the Clean Water Act; the character and volume of pollutants discharged into the POTW by the Significant Industrial User.

D. Facilities Operation

The permittee shall at all times maintain in good working order and properly operate and maintain all facilities and systems which are installed or used by the permittee to achieve compliance with the terms and conditions of this permit. Proper operation and maintenance includes, but is not limited to, adequate laboratory controls including appropriate quality assurance procedures. This provision also includes the operation of backup or auxiliary facilities or similar systems that are installed by the permittee, only when necessary to achieve compliance with the terms and conditions of this permit.

The permittee shall develop, install, and maintain Best Management Practices to control or abate the discharge of pollutants when the practices are reasonably necessary to achieve the effluent limitations and standards in this permit or to carry out the purposes and intent of the Clean Water Act, or when required to do so by the Department.

E. Duty to Mitigate

The permittee shall take all reasonable steps to minimize or prevent any discharge, sludge use or disposal in violation of this permit that has a reasonable likelihood of adversely affecting human health or the environment.

F. Bypassing

1. Bypassing Not Exceeding Permit Limitations - The permittee may allow a bypass to occur which does not cause effluent limitations to be violated, but only if the bypass is essential for maintenance to assure efficient operation. This type of bypassing is not subject to the reporting and notification requirements of PART A III.C.

2. Other Bypassing - In all other situations, bypassing is prohibited unless all of the following conditions are met:

   a. A bypass is unavoidable to prevent loss of life, personal injury, or "severe property damage."

   b. There are no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate backup equipment should have been installed (in the exercise of reasonable engineering judgment) to prevent a bypass that occurred during normal periods of equipment downtime or preventive maintenance.

   c. The permittee submitted the necessary reports required under PART A III.C.

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PART B

II. PENALTIES AND LIABILITY

A. Violations of Permit Conditions

Any person violating Sections 301, 302, 306, 307, 308, 318, or 405 of the Clean Water Act or any permit condition or limitation implementing such sections in a permit issued under Section 402 of the Act is subject to civil, administrative, and/or criminal penalties as set forth in 40 CFR Part 122.4l(a)(2).

Any person or municipality who violates any provision of this permit; any rule, regulation, or order of the Department; or any condition or limitation of any permit issued pursuant to The Clean Streams Law, is subject to criminal and/or civil penalties as set forth in Sections 602, 603, and 605 of The Clean Streams Law.

B. Falsifying Information

The Clean Water Act provides that any person who does any of the following:

- Falsifies, tampers with, or knowingly renders inaccurate any monitoring device or method required to be maintained under this permit, or

- Knowingly makes any false statement, representation, or certification in any record or other document submitted or required to be maintained under this permit (including monitoring reports or reports of compliance or noncompliance),

shall, upon conviction, be punished by a fine and/or imprisonment as set forth in 40 CFR Part 122.41(j)(5) and (k)(2).

C. Liability

Nothing in this permit shall be construed to relieve the permittee from civil or criminal penalties for noncompliance pursuant to Section 309 of the Clean Water Act or Sections 602, 603, or 605 of The Clean Streams Law.

Nothing in this permit shall be construed to preclude the institution of any legal action or to relieve the permittee from any responsibilities, liabilities, or penalties to which the permittee is or may be subject to under the Clean Water Act and The Clean Streams Law.

D. Enforcement Proceedings

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.

III. OTHER RESPONSIBILITIES

A. Right of Entry

Pursuant to Sections 5(b) and 305 of Pennsylvania's Clean Streams Law, and 25 Pa. Code Chapter 92, the permittee shall allow the Secretary of the Department, the EPA Regional Administrator, and/or their authorized representatives, upon the presentation of credentials and other documents as may be required by law:

PART B

1. To enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this permit;

2. To have access to and copy at reasonable times any records that must be kept under the conditions of this permit;

3. To inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices or operations regulated or required under this permit; and

4. To sample or monitor at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the Clean Water Act or The Clean Streams Law, any substances or parameters at any location.

B. Transfer of Permits

1. Transfers by modification. Except as provided in paragraph 2 of this section, a permit may be transferred by the permittee to a new owner or operator only if the permit has been modified or revoked and reissued, or a minor modification made to identify the new permittee and incorporate such other requirements as may be necessary under the Clean Water Act.

2. Automatic transfers. As an alternative to transfers under paragraph 1 of this section, any NPDES permit may be automatically transferred to a new permittee if:

   a. The current permittee notifies the Department at least 30 days in advance of the proposed transfer date in paragraph 2.b of this section;

   b. The notice includes the appropriate Department transfer form signed by the existing and new permittees containing a specific date for transfer of permit responsibility, coverage, and liability between them; and

   c. If the Department does not notify the existing permittee and the proposed new permittee of its intent to modify or revoke and reissue the permit, the transfer is effective on the date specified in the agreement mentioned in paragraph 2.b of this section.

3. In the event the Department does not approve transfer of the permit, the new owner or controller must submit a new permit application.

C. Property Rights

The issuance of this permit does not convey any property rights of any sort, or any exclusive privilege.

D. Other Laws

The issuance of a permit does not authorize any injury to persons or property or invasion of other private rights, or any infringement of State or local law or regulations.

PART C

I. OTHER REQUIREMENTS

A. Waterborne releases of radioactive materials to unrestricted areas shall conform to criteria set forth in Title 10 Code of Federal Regulations Part 50 Appendix I - Numerical Guides for Design Objectives and Limiting Conditions for Operation to meet the Criterion "As low as is reasonably achievable" for radioactive material in light-water-cooled nuclear reactor effluents, as implemented through the Off-Site Dose Calculation Manual for the facility.

The facility operator shall provide the Department with copies of reports specifying the quantities of radioactive materials released to unrestricted areas in liquid/gaseous effluents.

The facility operator shall provide the Department with copies of reports of the results of environmental surveillance activities and other such reports as necessary for the estimation of the dose consequential to facility operation.

The above reports are to be forwarded to the Department of Environmental Protection, Bureau of Radiation Protection.

B. There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid as determined by EPA Analysis Method 608 GC/ECD.

C. The discharge may not change the temperature of the receiving stream by more than 2° F in any one hour.

D. Neither free available chlorine nor total residual chlorine from cooling water systems 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 Department that the units in a particular location cannot operate at or below this level of chlorination.

E. In accordance with Best Professional Judgment and PADEP Guidance on Intake Structure Design, Location, Operation, and Maintenance, the TMI facility has been determined to be Best Technology Available for compliance with the Clean Water Act.

F. Sodium hypochlorite and sodium bromide as measured by Total Residual Oxidants (TRO) may be added for up to two hours per day to the TMI 1 Circulating Water System.

G. The term maximum daily concentration as it relates to chlorine discharge means the average analyses made over a single period of chlorine release which does not exceed two hours.

H. The permittee shall notify the Department within two working days after discharging from Outfalls 003 or 004 stating the composition of the discharge and the reason for discharging.

I. If the number of discharges for an outfall is less than the required monitoring frequency for that outfall, then the required monitoring frequency will be equal to the number of discharges for that outfall.

J. This permit is of interest to the U.S. Environmental Protection Agency (EPA) because it meets one or more of the following criteria:

1. POTW with a design hydraulic flow of one mgd or more.

2. POTW with a pretreatment requirement.

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PART C

3. POTW or Industrial Waste discharger with biomonitoring requirements.

4. Industrial Waste discharger not waived for review by the EPA/DEP Memorandum of Agreement.

A copy of the DMR shall be submitted to the EPA at the following address:

NPDES Discharge Monitoring Reports (3WP42)
Water Protection Division
U.S. Environmental Protection Agency, Region III
1650 Arch Street
Philadelphia, PA 19103-2029

K. In the event that a continuous flow or temperature instrument is out of service for longer than 24 hours, the Department shall be notified within 24 hours and the instrument shall be repaired as soon as reasonably possible. A temporary estimation or calculation method must be used and records kept available for Department review. The data collected while the instrument is out of service shall be used in preparation of the DMRs.

II. REQUIREMENTS APPLICABLE TO STORMWATER OUTFALLS

A. Prohibition of Nonstormwater Discharges

1. Except as provided in A.2, all stormwater outfalls shall be composed entirely of stormwater.

2. The following nonstormwater discharges may be authorized, provided the nonstormwater component of the discharge is in compliance with C.2.b: discharges from fire fighting activities; fire hydrant flushings, potable water sources including waterline flushings, irrigation drainage, lawn watering, routine external building washdown which does not use detergents or other compounds, pavement washwaters where spills or leaks of toxic or hazardous materials have not occurred (unless all spilled material has been removed) and where detergents are not used, air conditioning condensate, springs, uncontaminated groundwater, and foundation or footing drains where flows are not contaminated with process materials such as solvents.

B. Spills

This permit does not authorize the discharge of any toxic or hazardous substances or oil resulting from an on-site spill.

C. Preparedness, Prevention and Contingency Plans

1. Development of Plan

Operators of facilities shall have developed a Preparedness, Prevention and Contingency (PPC) Plan in accordance with 25 Pa. Code § 91.34 and the "Guidelines for the Development and Implementation of Environmental Emergency Response Plans". The PPC Plan shall identify potential sources of pollution that may reasonably be expected to affect the quality of stormwater discharges associated with industrial activity from the facility. In addition, the PPC Plan shall describe the implementation of practices that are to be used to reduce the pollutants in stormwater discharges associated with industrial activity at the facility ensuring compliance with the terms and conditions of this permit.

PART C

2. Nonstormwater Discharges

a. The PPC Plan shall contain a certification that the discharge has been tested or evaluated for the presence of nonstormwater discharges. The certification shall include the identification of potential significant sources of nonstormwater at the site, a description of the results of any test and/or evaluation for the presence of nonstormwater discharges, the evaluation criteria or testing methods used, the date of any testing and/or evaluation, and the on-site drainage points that were directly observed during the test. Such certification may not be feasible if the facility operating the stormwater discharge associated with industrial activity does not have access to an outfall, manhole, or other point of access to the ultimate conduit that receives the discharge. In such cases, the source identification section of the PPC Plan shall indicate why the certification was not feasible. A discharger that is unable to provide the certification must notify the Department within 180 days of the effective date of this permit.

b. Except for flows from fire fighting activities, sources of nonstormwater listed in A.2. (authorized nonstormwater discharges) that are combined with stormwater discharges associated with industrial activity must be identified in the plan. The plan shall identify and ensure the implementation of appropriate pollution prevention measures for the nonstormwater component(s) of the discharge.

3. Special Requirements for SARA Title III, Section 313 Facilities

a. Facilities subject to SARA Title III, Section 313 shall include in the PPC Plan a description of releases to land or water of Section 313 water priority chemicals that have occurred within the last three years. Each of the following shall be evaluated for the reasonable potential for contributing pollutants to runoff: loading and unloading operations, outdoor storage activities, outdoor manufacturing or processing activities, significant dust or particulate generating process, and on-site waste disposal practices. Factors to consider include the toxicity of chemicals; quantity of chemicals used, produced or discharged; the likelihood of contact with stormwater; and history of significant leaks or spills of toxic or hazardous pollutants.

b. Engineering Certification. No stormwater PPC Plan for facilities subject to SARA Title III, Section 313 requirements for chemicals that are classified as "Section 313 water priority chemicals" shall be effective unless it has been reviewed by a Registered Professional Engineer and certified to by such Professional Engineer. A Registered Professional Engineer shall recertify the PPC Plan every year thereafter. This certification may be combined with the required annual certification in C.4. By means of these certifications, the engineer, having examined the facility and being familiar with the provisions of this part, shall attest that the stormwater PPC Plan has been prepared in accordance with good engineering practices. Such certification shall in no way relieve the owner or operator of a facility covered by the PPC Plan of the duty to prepare and fully implement such Plan.

4. Comprehensive Site Compliance Evaluations and Record Keeping

Qualified personnel shall conduct site compliance evaluations at appropriate intervals specified in the plan, but, in no case less than once a year. Such evaluations shall provide:

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a. Areas contributing to a stormwater discharge associated with industrial activity shall be visually inspected for evidence of, or the potential for, pollutants entering the drainage system. Measures to reduce pollutant loadings shall be evaluated to determine whether they are adequate and properly implemented in accordance with the terms of the permit or whether additional control measures are needed. Structural stormwater management measures, sediment and erosion control measures, and other structural pollution prevention measures identified in the plan shall be observed to ensure that they are operating correctly. A visual inspection of equipment needed to implement the plan, such as spill response equipment, shall be made.

b. Based on the results of the inspection, the description of potential pollutant sources identified in the PPC plan, and pollution prevention measures and controls identified in the plan shall be revised as appropriate within 15 days of such inspection and shall provide for implementation of any changes to the plan in a timely manner, but in no case more than 90 days after the inspection.

D. Stormwater Sampling and Reporting

1. All samples shall be collected from the discharge resulting from a storm event that is greater than 0.1 inches in magnitude and that occurs at least 72 hours from the previously measurable (greater than 0.1 inches) storm event.

2. When the discharger is unable to collect samples due to adverse climatic conditions, the discharger must submit, in lieu of sampling data, a description of why samples could not be collected, including available documentation of the event. This sampling waiver may not be used more than once during a two-year period.

3. Grab samples shall be collected during the first 30 minutes of the discharge.

4. Stormwater monitoring results shall be summarized on a DMR form and the Department's "Additional Information for the Reporting of Stormwater Monitoring" form.

5. When a facility has two or more outfalls that may reasonably be believed to discharge substantially identical effluents, based on a consideration of features and activities within the area drained by the outfall, the permittee may sample one such outfall and report that the quantitative data also applies to the substantially identical outfalls.

6. The following table describes the outfall locations and drainage areas.

Outfall No.	Acreage	Latitude	Longitude
005A	115.5	40°09'06"	76°43'18"
SO1	16.6	40°08'58"	76°43'19"
SO2	11.9	40°08'53"	76°43'19"
SO3	21.5	40°08'45"	76°43'21"
SO4	0.7	40°09'15"	76°43'41"

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III. CONTROLLING CHEMICAL ADDITIVES USAGE RATES

A. Chemical additives to control corrosion, scaling, algae, slime, fouling, oxygen, etc., and blow down discharge rates shall be managed by the permittee to ensure that toxic effects in the receiving stream are prevented. Usage rates shall be limited to the minimum amount necessary to accomplish the intended purposes of chemical addition and to comply with the effluent limitations contained in Part A of this permit. Approval is limited to chemicals and usage rates contained in the application and in previous approval letters.

B. The additives currently approved are the following:

Ammonium Hydroxide Solution	GE Betz Depositrol PY 5203
GE Betz Inhibitor AZ 8103	GE Betz Depositrol PY 5204
GE Betz Inhibitor AZ 8100	GE Betz Depositrol SF 502
GE Betz Spectrus CT 1300	GE Betz Flogard MS 6208
GE Betz Spectrus DT 1400	GE Betz Flogard MS 6209
GE Betz Spectrus NX 1106	GE Betz HPC 19M
GE Betz Spectrus OX 1201	Hydrazine
GE Betz Steamate PWR 0160	Hydrogen Peroxide
GE Betz Steamate PWR 1440	Lithium Hydroxide
Boric Acid	Sodium Hydroxide
GE Betz Continuum AEC 3107	Sodium Hypochlorite
Chlorine	Sulfuric Acid
GE Betz Cortrol IS 104	Wood Flour
GE Betz Cortrol OS 5010	Zinc Acetate Dihydrate
GE Betz Depositrol PY 5206	Zinc Orthophosphate

C. Whenever a change in additives or increase in usage rates is desired by the permittee (changes in chemical additive vendors need not be submitted as long as the chemical is substantially the same as one previously approved), a written notification in the format specified by the Department, shall be submitted at least 60 days prior to the proposed use of the chemical. For each proposed chemical or usage rate, the written notification, as a minimum, shall include the following:

1. Trade names of additive.
2. Name and address of additive manufacturer.
3. Material Safety Data Sheet (MSDS) or other available information on mammalian or aquatic toxicological effects.
4. Bioassay data including the 96-hour LC50 on the whole product.
5. Proposed average and maximum additive usage rates in lbs/day.
6. A flow diagram showing the point of chemical addition and the affected outfalls.
7. The expected concentration of the product at the final outfall.
8. The product density for liquids (lbs/gal) used to convert usage rate (gpd) to in-system concentrations (mg/l).

PART C

9. The analytical test method that could be used to verify final discharge concentrations when the product is in use and the associated minimum analytical detection level (mg/l).

10. Conditioned water discharge rate (blowdown rate) and duration (hours).

11. Available data on the degradation of or decomposition of the additive in the aquatic environment.

12. Any other data or information the permittee believes would be helpful to the Department in completing its review.

D. Use of products or chemicals that contain one or more ingredients that are carcinogens is generally prohibited. Before proposing limited use of such products or chemicals, the permittee must first thoroughly investigate use of alternate products or chemicals to avoid the use of the carcinogens. If no suitable alternatives are available, the permittee must submit written documentation as part of the information required above, that demonstrates to the satisfaction of the Department that no suitable alternatives are available and that any carcinogen in the proposed chemical or product will not be detectable in the final effluent using the most sensitive analytical method available.

E. Accurate records of usage (name of additive, quantity added, date added) of any approved chemical additive and of blow down discharge volumes must be maintained and kept on-site by the permittee. All correspondence and notifications related to the chemical additives usage rates must also be kept on-site with the required daily chemical usage records. If the notification is incomplete or the Department notifies the permittee that the proposed usage rate will cause violations of water quality standards, then use of the requested chemical additive or requested change in its usage rate will be denied.

F. Based on the information presented, the Department will determine within 60 days whether the existing NPDES permit must be amended to include specific effluent limitations for active ingredients or other control measures. When so required, the permittee will be advised within 60 days that a formal request for a permit amendment is required including a filing fee and Act 14 notices.

If a permit amendment application is not requested within 60 days, the permittee may proceed with the use of the proposed chemical additive or usage rate.

NAME AmerGen Energy Company, LLC
ADDRESS Route 441 South
PO Box 480
Middletown, PA 17057-0480

FACILITY Main Station Outfall
LOCATION Londonderry Township, Dauphin County
WATERSHED 7-G

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES)
DISCHARGE MONITORING REPORT

PA 0009920					OUTFALL 001		
MONITORING PERIOD							
	YEAR	MO	DAY		YEAR	MO	DAY
FROM:				TO:			

PAGE 1 OF 1

NOTE: READ INSTRUCTIONS BEFORE COMPLETING THIS FORM

PARAMETER		QUANTITY OR LOADING AVERAGE	QUANTITY OR LOADING MAXIMUM	UNITS	QUALITY OR CONCENTRATION MINIMUM	QUALITY OR CONCENTRATION AVERAGE	QUALITY OR CONCENTRATION MAXIMUM	UNITS	NO EX	ANALYSIS FREQUENCY	SAMPLE TYPE
Flow	SAMPLE MEASUREMENT				XXX	XXX	XXX				
	PERMIT REQUIREMENT	Report Avg Mo	Report Max Daily	MGD	XXX	XXX	XXX	X	X	Continuous	Recorded
pH	SAMPLE MEASUREMENT	XXX	XXX			XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	6.0 Minimum	XXX	9.0 Maximum	S.U.	X	2/month	Grab
Total Suspended Solids	SAMPLE MEASUREMENT	XXX	XXX		XXX						
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	Report Avg Mo	Report Max Daily	mg/l	X	2/month	Grab
Temperature (10/1 to 3/31)	SAMPLE MEASUREMENT	XXX	XXX		XXX	XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	XXX	110 Max Daily	°F	X	Continuous	Recorded
Temperature (4/1 to 9/30)	SAMPLE MEASUREMENT	XXX	XXX		XXX	XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	XXX	115 Max Daily	°F	X	Continuous	Recorded
Free Available Chlorine	SAMPLE MEASUREMENT	XXX	XXX		XXX	XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	XXX	0.2 Max Daily	mg/l	X	(1)	(1)
Total Residual Oxidants (TRO)	SAMPLE MEASUREMENT	XXX	XXX		XXX	XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	XXX	0.14 Max Daily	mg/l	X	(1)	(1)
Betz Spectrus CT 1300	SAMPLE MEASUREMENT	XXX	XXX		XXX	XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	XXX	0.1 Max Daily	mg/l	X	(1)	(1)
Hydrazine	SAMPLE MEASUREMENT	XXX	XXX		XXX	XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	XXX	Not Detectable I-max	mg/l	X	(1)	(1)

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted based on my inquiry of the person or persons who manage the system or those persons directly responsible for gathering the information. The information submitted is to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations. See Pa. C.S. § 4904 (relating to unsworn falsification).

		TELEPHONE		DATE		
NAME/TITLE PRINCIPAL EXECUTIVE OFFICER TYPE OR PRINTED	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OF AUTHORIZED AGENT	AREA CODE	NUMBER	YEAR	MO	DAY

COMMENT AND EXPLANATION OF ANY VIOLATIONS (PLEASE USE SEPARATE SHEET OF PAPER IF NECESSARY).

(1) Once per week grab samples during chemical addition. Refer to Permit for further explanation.

NAME AmerGen Energy Company, LLC
ADDRESS Route 441 South
PO Box 480
Middletown, PA 17057-0480

FACILITY Sewage Treatment Plant
LOCATION Londonderry Township, Dauphin County
WATERSHED 7-G

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES)
DISCHARGE MONITORING REPORT

PA 0009920					OUTFALL 101		
MONITORING PERIOD							
	YEAR	MO	DAY		YEAR	MO	DAY
FROM:				TO:			

PAGE 1 OF 1

NOTE: READ INSTRUCTIONS BEFORE COMPLETING THIS FORM

PARAMETER		QUANTITY OR LOADING AVERAGE	QUANTITY OR LOADING MAXIMUM	QUANTITY OR LOADING UNITS	QUALITY OR CONCENTRATION MINIMUM	QUALITY OR CONCENTRATION AVERAGE	QUALITY OR CONCENTRATION MAXIMUM	QUALITY OR CONCENTRATION UNITS	NO EX	ANALYSIS FREQUENCY	SAMPLE TYPE
FLOW	SAMPLE MEASUREMENT				XXX	XXX	XXX				
	PERMIT REQUIREMENT	Report Avg Mo	Report Max Daily	MGD	XXX	XXX	XXX	XXX	X	Continuous	Recorded
FECAL COLIFORM (5/1 to 9/30)	SAMPLE MEASUREMENT	XXX	XXX		XXX		XXX				
	PERMIT REQUIREMENT	XXX	XXX	XXX	XXX	200 30 Day Geo	XXX	No. 100 ml	X	1/quarter	Grab
FECAL COLIFORM (10/1 to 4/30)	SAMPLE MEASUREMENT	XXX	XXX		XXX		XXX				
	PERMIT REQUIREMENT	XXX	XXX	XXX	XXX	2,000 30 Day Geo	XXX	No. 100 ml	X	1/quarter	Grab
TOTAL SUSPENDED SOLIDS	SAMPLE MEASUREMENT	XXX	XXX		XXX		XXX				
	PERMIT REQUIREMENT	XXX	XXX	XXX	XXX	30 Avg Mo	XXX	mg/l	X	1/quarter	8-hr comp
5-DAY CBOD	SAMPLE MEASUREMENT	XXX	XXX		XXX		XXX				
	PERMIT REQUIREMENT	XXX	XXX	XXX	XXX	25 Avg Mo	XXX	mg/l	X	1/quarter	8-hr comp
TOTAL PHOSPHORUS	SAMPLE MEASUREMENT	XXX	XXX		XXX		XXX				
	PERMIT REQUIREMENT	XXX	XXX	XXX	XXX	2.0 Avg Mo	XXX	mg/l	X	1/quarter	8-hr comp

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted based on my inquiry of the person or persons who manage the system or those persons directly responsible for gathering the information. The information submitted is to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations. See Pa. C.S. § 4904 (relating to unsworn falsification).

		TELEPHONE		DATE		
NAME/TITLE PRINCIPAL EXECUTIVE OFFICER TYPE OR PRINTED	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OF AUTHORIZED AGENT	AREA CODE	NUMBER	YEAR	MO	DAY

COMMENT AND EXPLANATION OF ANY VIOLATIONS (PLEASE USE SEPARATE SHEET OF PAPER IF NECESSARY).

NAME AmerGen Energy Company, LLC
ADDRESS Route 441 South
PO Box 480
Middletown, PA 17057-0480

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES)
DISCHARGE MONITORING REPORT

PA 0009920				OUTFALL 401			
MONITORING PERIOD							
	YEAR	MO	DAY		YEAR	MO	DAY
FROM:				TO:			

PAGE 1 OF 1

FACILITY Industrial Waste Filter System
LOCATION Londonderry Township, Dauphin County
WATERSHED 7-G

NOTE: READ INSTRUCTIONS BEFORE COMPLETING THIS FORM

PARAMETER		QUANTITY OR LOADING AVERAGE	QUANTITY OR LOADING MAXIMUM	UNITS	QUALITY OR CONCENTRATION MINIMUM	QUALITY OR CONCENTRATION AVERAGE	QUALITY OR CONCENTRATION MAXIMUM	UNITS	NO EX	ANALYSIS FREQUENCY	SAMPLE TYPE
FLOW	SAMPLE MEASUREMENT				XXX	XXX	XXX				
	PERMIT REQUIREMENT	Report Avg Mo	Report Max Daily	MGD	XXX	XXX	XXX	XXX	X	Continuous	Recorded
pH	SAMPLE MEASUREMENT	XXX	XXX			XXX					
	PERMIT REQUIREMENT	XXX	XXX	XXX	6.0 Minimum	XXX	9.0 Maximum	S.U.	X	1/quarter	Grab
TSS	SAMPLE MEASUREMENT	XXX	XXX		XXX						
	PERMIT REQUIREMENT	XXX	XXX	XXX	XXX	30 Avg Mo	100 Max Daily	mg/l	X	1/quarter	Grab
OIL AND GREASE	SAMPLE MEASUREMENT	XXX	XXX		XXX						
	PERMIT REQUIREMENT	XXX	XXX	XXX	XXX	15 Avg Mo	20 Max Daily	mg/l	X	1/quarter	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted based on my inquiry of the person or persons who manage the system or those persons directly responsible for gathering the information. The information submitted is to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations. See Pa. C.S. § 4904 (relating to unsworn falsification).

		TELEPHONE		DATE		
NAME/TITLE PRINCIPAL EXECUTIVE OFFICER TYPE OR PRINTED	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OF AUTHORIZED AGENT	AREA CODE	NUMBER	YEAR	MO	DAY

COMMENT AND EXPLANATION OF ANY VIOLATIONS (PLEASE USE SEPARATE SHEET OF PAPER IF NECESSARY).

NAME AmerGen Energy Company, LLC
ADDRESS Route 441 South
PO Box 480
Middletown, PA 17057-0480

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES)
DISCHARGE MONITORING REPORT

PA 0009920					OUTFALL 501		
MONITORING PERIOD							
	YEAR	MO	DAY		YEAR	MO	DAY
FROM:				TO:			

PAGE 1 OF 1

FACILITY Unit 1 Secondary Neutralizer Tank
LOCATION Londonderry Township, Dauphin County
WATERSHED 7-G

NOTE: READ INSTRUCTIONS BEFORE COMPLETING THIS FORM

		QUANTITY OR LOADING			QUALITY OR CONCENTRATION				NO	ANALYSIS	SAMPLE
PARAMETER		AVERAGE	MAXIMUM	UNITS	MINIMUM	AVERAGE	MAXIMUM	UNITS	EX	FREQUENCY	TYPE
FLOW	SAMPLE MEASUREMENT				XXX	XXX	XXX				
	PERMIT REQUIREMENT	Report Avg Mo	Report Max Daily	MGD	XXX	XXX	XXX	XXX	X	2/month	Calc.
pH	SAMPLE MEASUREMENT	XXX	XXX			XXX					
	PERMIT REQUIREMENT	XXX	XXX	XXX	6.0 Minimum	XXX	9.0 Maximum	S.U.	X	2/month	Grab
TSS	SAMPLE MEASUREMENT	XXX	XXX		XXX						
	PERMIT REQUIREMENT	XXX	XXX	XXX	XXX	30 Avg Mo	100 Max Daily	mg/l	X	2/month	Grab
Oil and Grease	SAMPLE MEASUREMENT	XXX	XXX		XXX						
	PERMIT REQUIREMENT	XXX	XXX	XXX	XXX	15 Avg Mo	20 Max Daily	mg/l	X	1/quarter	Grab

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NAME/TITLE PRINCIPAL EXECUTIVE OFFICER TYPE OR PRINTED	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OF AUTHORIZED AGENT	AREA CODE	NUMBER	YEAR	MO	DAY

COMMENT AND EXPLANATION OF ANY VIOLATIONS (PLEASE USE SEPARATE SHEET OF PAPER IF NECESSARY).

NAME AmerGen Energy Company, LLC
ADDRESS Route 441 South
PO Box 480
Middletown, PA 17057-0480

FACILITY Industrial Waste Treatment System
LOCATION Londonderry Township, Dauphin County
WATERSHED 7-G

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES)
DISCHARGE MONITORING REPORT

PA 0009920					OUTFALL 701		
MONITORING PERIOD							
	YEAR	MO	DAY		YEAR	MO	DAY
FROM:				TO:			

PAGE 1 OF 1

NOTE: READ INSTRUCTIONS BEFORE COMPLETING THIS FORM

		QUANTITY OR LOADING			QUALITY OR CONCENTRATION				NO	ANALYSIS	SAMPLE
PARAMETER		AVERAGE	MAXIMUM	UNITS	MINIMUM	AVERAGE	MAXIMUM	UNITS	EX	FREQUENCY	TYPE
FLOW	SAMPLE MEASUREMENT				XXX	XXX	XXX				
	PERMIT REQUIREMENT	Report Avg Mo	Report Max Daily	MGD	XXX	XXX	XXX	XXX	X	Continuous	Recorded
pH	SAMPLE MEASUREMENT	XXX	XXX			XXX					
	PERMIT REQUIREMENT	XXX	XXX	XXX	6.0 Minimum	XXX	9.0 Maximum	S.U.	X	2/month	Grab
TSS	SAMPLE MEASUREMENT	XXX	XXX		XXX						
	PERMIT REQUIREMENT	XXX	XXX	XXX	XXX	30 Avg Mo	100 Max Daily	mg/l	X	2/month	Grab
Oil and Grease	SAMPLE MEASUREMENT	XXX	XXX		XXX						
	PERMIT REQUIREMENT	XXX	XXX	XXX	XXX	15 Avg Mo	20 Max Daily	mg/l	X	1/quarter	Grab

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COMMENT AND EXPLANATION OF ANY VIOLATIONS (PLEASE USE SEPARATE SHEET OF PAPER IF NECESSARY).

NAME AmerGen Energy Company, LLC
ADDRESS Route 441 South
PO Box 480
Middletown, PA 17057-0480

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES)
DISCHARGE MONITORING REPORT

PA 0009920					OUTFALL 003		
MONITORING PERIOD							
	YEAR	MO	DAY		YEAR	MO	DAY
FROM:				TO:			

PAGE 1 OF 1

FACILITY Emergency Discharge (001 blockage)
LOCATION Londonderry Township, Dauphin County
WATERSHED 7-G

NOTE: READ INSTRUCTIONS BEFORE COMPLETING THIS FORM

PARAMETER		QUANTITY OR LOADING AVERAGE	QUANTITY OR LOADING MAXIMUM	QUANTITY OR LOADING UNITS	QUALITY OR CONCENTRATION MINIMUM	QUALITY OR CONCENTRATION AVERAGE	QUALITY OR CONCENTRATION MAXIMUM	QUALITY OR CONCENTRATION UNITS	NO EX	ANALYSIS FREQUENCY	SAMPLE TYPE
Flow	SAMPLE MEASUREMENT				XXX	XXX	XXX				
	PERMIT REQUIREMENT	Report Avg Mo	Report Max Daily	MGD	XXX	XXX	XXX	X	X	1/day	Estimated
pH	SAMPLE MEASUREMENT	XXX	XXX			XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	6.0 Minimum	XXX	9.0 Maximum	S.U.	X	2/month	Grab
Total Suspended Solids	SAMPLE MEASUREMENT	XXX	XXX		XXX						
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	Report Avg Mo	Report Max Daily	mg/l	X	2/month	Grab
Temperature (10/1 to 3/31)	SAMPLE MEASUREMENT	XXX	XXX		XXX	XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	XXX	110 Max Daily	°F	X	1/shift	"i-s"
Temperature (4/1 to 9/30)	SAMPLE MEASUREMENT	XXX	XXX		XXX	XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	XXX	115 Max Daily	°F	X	1/shift	"i-s"
Free Available Chlorine	SAMPLE MEASUREMENT	XXX	XXX		XXX	XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	XXX	0.2 Max Daily	mg/l	X	(1)	(1)
Total Residual Oxidants (TRO)	SAMPLE MEASUREMENT	XXX	XXX		XXX	XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	XXX	0.14 Max Daily	mg/l	X	(1)	(1)
Betz Spectrus CT 1300	SAMPLE MEASUREMENT	XXX	XXX		XXX	XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	XXX	0.1 Max Daily	mg/l	X	(1)	(1)
Hydrazine	SAMPLE MEASUREMENT	XXX	XXX		XXX	XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	XXX	Not Detect-able I-max	mg/l	X	(1)	(1)

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NAME/TITLE PRINCIPAL EXECUTIVE OFFICER TYPE OR PRINTED	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OF AUTHORIZED AGENT	TELEPHONE AREA CODE	TELEPHONE NUMBER	DATE YEAR	DATE MO	DATE DAY

COMMENT AND EXPLANATION OF ANY VIOLATIONS (PLEASE USE SEPARATE SHEET OF PAPER IF NECESSARY).

(1) Once per week grab samples during chemical addition. Refer to Permit for further explanation.

NAME AmerGen Energy Company, LLC
ADDRESS Route 441 South
PO Box 480
Middletown, PA 17057-0480

FACILITY Emergency Discharge (MDCT blockage)
LOCATION Londonderry Township, Dauphin County
WATERSHED 7-G

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES)
DISCHARGE MONITORING REPORT

PA 0009920				OUTFALL 004		
MONITORING PERIOD						
	YEAR	MO	DAY		YEAR	MO	DAY
FROM:				TO:			

PAGE 1 OF 1

NOTE: READ INSTRUCTIONS BEFORE COMPLETING THIS FORM

		QUANTITY OR LOADING			QUALITY OR CONCENTRATION				NO	ANALYSIS	SAMPLE
PARAMETER		AVERAGE	MAXIMUM	UNITS	MINIMUM	AVERAGE	MAXIMUM	UNITS	EX	FREQUENCY	TYPE
Flow	SAMPLE MEASUREMENT				XXX	XXX	XXX				
	PERMIT REQUIREMENT	Report Avg Mo	Report Max Daily	MGD	XXX	XXX	XXX	X	X	1/day	Estimated
pH	SAMPLE MEASUREMENT	XXX	XXX			XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	6.0 Minimum	XXX	9.0 Maximum	S.U.	X	2/month	Grab
Total Suspended Solids	SAMPLE MEASUREMENT	XXX	XXX		XXX						
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	Report Avg Mo	Report Max Daily	mg/l	X	2/month	Grab
Temperature	SAMPLE MEASUREMENT	XXX	XXX		XXX	XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	XXX	Report Max Daily	°F	X	1/shift	"i-s"
Free Available Chlorine	SAMPLE MEASUREMENT	XXX	XXX		XXX	XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	XXX	0.2 Max Daily	mg/l	X	(1)	(1)
Total Residual Oxidants (TRO)	SAMPLE MEASUREMENT	XXX	XXX		XXX	XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	XXX	0.14 Max Daily	mg/l	X	(1)	(1)
Betz Spectrus CT 1300	SAMPLE MEASUREMENT	XXX	XXX		XXX	XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	XXX	0.1 Max Daily	mg/l	X	(1)	(1)
Hydrazine	SAMPLE MEASUREMENT	XXX	XXX		XXX	XXX					
	PERMIT REQUIREMENT	XXX	XXX	X	XXX	XXX	Not Detectable I-max	mg/l	X	(1)	(1)

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NAME/TITLE PRINCIPAL EXECUTIVE OFFICER TYPE OR PRINTED	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OF AUTHORIZED AGENT	AREA CODE	NUMBER	YEAR	MO	DAY

COMMENT AND EXPLANATION OF ANY VIOLATIONS (PLEASE USE SEPARATE SHEET OF PAPER IF NECESSARY).

(1) Once per week grab samples during chemical addition. Refer to Permit for further explanation.

NAME AmerGen Energy Company, LLC
ADDRESS Route 441 South
PO Box 480
Middletown, PA 17057-0480

FACILITY Storm Water
LOCATION Londonderry Township, Dauphin County
WATERSHED 7-G

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES)
DISCHARGE MONITORING REPORT

PA 0009920				OUTFALL 005A			
MONITORING PERIOD							
	YEAR	MO	DAY		YEAR	MO	DAY
FROM:				TO:			

PAGE 1 OF 1

NOTE: READ INSTRUCTIONS BEFORE COMPLETING THIS FORM

PARAMETER		QUALITY OR CONCENTRATION COMPOSITE	GRAB	UNITS	NO EX	ANALYSIS FREQUENCY	SAMPLE TYPE
Oil and Grease	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
pH	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	S.U.	X	1/year	Grab
5-DAY CBOD	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
CHEMICAL OXYGEN DEMAND	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
TOTAL SUSPENDED SOLIDS	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
TOTAL KJELDAHL NITROGEN	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
TOTAL PHOSPHORUS	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
IRON, DISSOLVED	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab

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COMMENT AND EXPLANATION OF ANY VIOLATIONS (PLEASE USE SEPARATE SHEET OF PAPER IF NECESSARY).

NAME AmerGen Energy Company, LLC
ADDRESS Route 441 South
PO Box 480
Middletown, PA 17057-0480

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES)
DISCHARGE MONITORING REPORT

PA 0009920				OUTFALL 005B		
MONITORING PERIOD						
	YEAR	MO	DAY		YEAR	MO	DAY
FROM:				TO:			

PAGE 1 OF 1

FACILITY Miscellaneous Industrial Wastewater
LOCATION Londonderry Township, Dauphin County
WATERSHED 7-G

NOTE: READ INSTRUCTIONS BEFORE COMPLETING THIS FORM

		QUANTITY OR LOADING			QUALITY OR CONCENTRATION				NO	ANALYSIS	SAMPLE
PARAMETER		AVERAGE	MAXIMUM	UNITS	MINIMUM	AVERAGE	MAXIMUM	UNITS	EX	FREQUENCY	TYPE
FLOW	SAMPLE MEASUREMENT				XXX	XXX	XXX				
	PERMIT REQUIREMENT	Report Avg Mo	Report Max Daily	MGD	XXX	XXX	XXX	XXX	X	1/month	Est.
pH	SAMPLE MEASUREMENT	XXX	XXX			XXX					
	PERMIT REQUIREMENT	XXX	XXX	XXX	6.0 Minimum	XXX	9.0 Maximum	S.U.	X	2/month	Grab
TSS	SAMPLE MEASUREMENT	XXX	XXX		XXX						
	PERMIT REQUIREMENT	XXX	XXX	XXX	XXX	30 Avg Mo	100 Max Daily	mg/l	X	2/month	Grab
Oil and Grease	SAMPLE MEASUREMENT	XXX	XXX		XXX						
	PERMIT REQUIREMENT	XXX	XXX	XXX	XXX	15 Avg Mo	20 Max Daily	mg/l	X	2/month	Grab

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COMMENT AND EXPLANATION OF ANY VIOLATIONS (PLEASE USE SEPARATE SHEET OF PAPER IF NECESSARY).

NAME AmerGen Energy Company, LLC
ADDRESS Route 441 South
PO Box 480
Middletown, PA 17057-0480

FACILITY Storm Water
LOCATION Londonderry Township, Dauphin County
WATERSHED 7-G

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES)
DISCHARGE MONITORING REPORT

PA 0009920				OUTFALL SO1			
MONITORING PERIOD							
	YEAR	MO	DAY		YEAR	MO	DAY
FROM:				TO:			

PAGE 1 OF 1

NOTE: READ INSTRUCTIONS BEFORE COMPLETING THIS FORM

PARAMETER		QUALITY OR CONCENTRATION COMPOSITE	GRAB	UNITS	NO EX	ANALYSIS FREQUENCY	SAMPLE TYPE
Oil and Grease	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
pH	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	S.U.	X	1/year	Grab
5-DAY CBOD	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
CHEMICAL OXYGEN DEMAND	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
TOTAL SUSPENDED SOLIDS	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
TOTAL KJELDAHL NITROGEN	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
TOTAL PHOSPHORUS	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
IRON, DISSOLVED	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab

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COMMENT AND EXPLANATION OF ANY VIOLATIONS (PLEASE USE SEPARATE SHEET OF PAPER IF NECESSARY).

NAME AmerGen Energy Company, LLC
ADDRESS Route 441 South
PO Box 480
Middletown, PA 17057-0480

FACILITY Storm Water
LOCATION Londonderry Township, Dauphin County
WATERSHED 7-G

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES)
DISCHARGE MONITORING REPORT

PA 0009920				OUTFALL SO2			
MONITORING PERIOD							
	YEAR	MO	DAY		YEAR	MO	DAY
FROM:				TO:			

PAGE 1 OF 1

NOTE: READ INSTRUCTIONS BEFORE COMPLETING THIS FORM

PARAMETER		QUALITY OR CONCENTRATION COMPOSITE	GRAB	UNITS	NO EX	ANALYSIS FREQUENCY	SAMPLE TYPE
Oil and Grease	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
pH	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	S.U.	X	1/year	Grab
5-DAY CBOD	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
CHEMICAL OXYGEN DEMAND	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
TOTAL SUSPENDED SOLIDS	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
TOTAL KJELDAHL NITROGEN	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
TOTAL PHOSPHORUS	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
IRON, DISSOLVED	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab

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COMMENT AND EXPLANATION OF ANY VIOLATIONS (PLEASE USE SEPARATE SHEET OF PAPER IF NECESSARY).

NAME AmerGen Energy Company, LLC
ADDRESS Route 441 South
PO Box 480
Middletown, PA 17057-0480

FACILITY Storm Water
LOCATION Londonderry Township, Dauphin County
WATERSHED 7-G

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES)
DISCHARGE MONITORING REPORT

PA 0009920				OUTFALL SO3		
MONITORING PERIOD						
	YEAR	MO	DAY		YEAR	MO	DAY
FROM:				TO:			

PAGE 1 OF 1

NOTE: READ INSTRUCTIONS BEFORE COMPLETING THIS FORM

PARAMETER		QUALITY OR CONCENTRATION COMPOSITE	GRAB	UNITS	NO EX	ANALYSIS FREQUENCY	SAMPLE TYPE
Oil and Grease	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
pH	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	S.U.	X	1/year	Grab
5-DAY CBOD	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
CHEMICAL OXYGEN DEMAND	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
TOTAL SUSPENDED SOLIDS	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
TOTAL KJELDAHL NITROGEN	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
TOTAL PHOSPHORUS	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
IRON, DISSOLVED	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab

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COMMENT AND EXPLANATION OF ANY VIOLATIONS (PLEASE USE SEPARATE SHEET OF PAPER IF NECESSARY).

NAME AmerGen Energy Company, LLC
ADDRESS Route 441 South
PO Box 480
Middletown, PA 17057-0480

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES)
DISCHARGE MONITORING REPORT

PA 0009920				OUTFALL SO4			
MONITORING PERIOD							
	YEAR	MO	DAY		YEAR	MO	DAY
FROM:				TO:			

PAGE 1 OF 1

FACILITY Storm Water
LOCATION Londonderry Township, Dauphin County
WATERSHED 7-G

NOTE: READ INSTRUCTIONS BEFORE COMPLETING THIS FORM

PARAMETER		QUALITY OR CONCENTRATION COMPOSITE	GRAB	UNITS	NO EX	ANALYSIS FREQUENCY	SAMPLE TYPE
Oil and Grease	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
pH	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	S.U.	X	1/year	Grab
5-DAY CBOD	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
CHEMICAL OXYGEN DEMAND	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
TOTAL SUSPENDED SOLIDS	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
TOTAL KJELDAHL NITROGEN	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
TOTAL PHOSPHORUS	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab
IRON, DISSOLVED	SAMPLE MEASUREMENT	XXX					
	PERMIT REQUIREMENT	XXX	Monitor & Report	mg/l	X	1/year	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted based on my inquiry of the person or persons who manage the system or those persons directly responsible for gathering the information. The information submitted is to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations. See Pa. C.S. § 4904 (relating to unsworn falsification).

NAME/TITLE PRINCIPAL EXECUTIVE OFFICER TYPE OR PRINTED	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OF AUTHORIZED AGENT	TELEPHONE AREA CODE	NUMBER	DATE YEAR	MO	DAY

COMMENT AND EXPLANATION OF ANY VIOLATIONS (PLEASE USE SEPARATE SHEET OF PAPER IF NECESSARY).

DISHARGE MONITORING REPORT SUPPLEMENTAL FORM (W)
AmerGen Energy Co., LLC (TMI Nuclear Station) **7-G Watershed**
Londonderry Township, Dauphin County

For the MONTH ______________________ 20____

Renewal application **DUE DATE** is **APRIL 30, 2012.**
This permit will **EXPIRE** on **OCTOBER 31, 2012.**

DAY	Flow	pH	TSS	Temp	Cl_2 Free	Total Residual Oxidants (TRO)	Spectrus CT 1300	Hydrazine	Comments
	MGD	*S.U.*	*mg/l*	*°F*	*mg/l*	*mg/l*	*mg/l*	*mg/l*	
1									
2									
3									
4									
5									
6									
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26									
27									
28									
29									
30									
31									
Avg									

Laboratory Name: ______________________ In house? ______ Signature ______________________

NPDES Permit **PA 0009920** for Outfall 001 Telephone: (______) ______________________

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DISCHARGE MONITORING REPORT SUPPLEMENTAL FORM (W)
AmerGen Energy Co., LLC (TMI Nuclear Station) **7-G Watershed**
Londonderry Township, Dauphin County

For the MONTH ______________________ *20*____

Renewal application **DUE DATE** is **APRIL 30, 2012.**
This permit will **EXPIRE** on **OCTOBER 31, 2012.**

DAY	Outfall 501				Outfall 701				Outfall 005B				Comments
	Flow *MGD*	pH *SU*	TSS *mg/l*	O&G *mg/l*	Flow *MGD*	pH *mg/l*	TSS *mg/l*	O&G *mg/l*	Flow *MGD*	pH *mg/l*	TSS *mg/l*	O&G *mg/l*	
1													
2													
3													
4													
5													
6													
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30													
31													
Avg													

Laboratory Name: ______________________ In house? ____ Signature ______________________

NPDES Permit **PA 0009920** for Outfalls 501, 701, and 005B Telephone: (   ) ______________________

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SCFO Form 09/94

Non-Compliance Discharge Report - NPDES Permit **PA (PERMIT #)**

AmerGen Energy Co., LLC (TMI Nuclear Station) **7-G Watershed**
Londonderry Township, Dauphin County

1. A non-compliance discharge of ______________________________
   occurred on this (these) dates: ______________________________

2. The impact on the receiving water was (circle those that apply): 1. **Foam** 2. **Sheen** 3. **Discoloration** 4. **Odors** 5. **Solids deposited** 6. **Fishkill**
   7. **Did not determine** 8. **Other** (describe): ______________________________

3. The cause of the non-compliance discharge was: ______________________________
   ____

4. The non-compliance discharge continued from the period of (date) ______________ and (time) ______________
   to (date) ______________ and (time) ______________ or will continue until (date) ______________
   and (time) ______________

5. The following action is being taken to **prevent** a recurrence or another non-compliance discharge of this nature: ______________
   ____
   ____
   ____

6. The following analyses were made to determine the impact and the extent of the impact upon the receiving waters (effluent, stream, other): ______________
   ____
   ____
   ____

7. The Department of Environmental Protection was notified of the non-compliance on (date) ______________ at (time) ______________
   The person(s) contacted was (were): ______________________________

Signature ______________ Title ______________ Date ______________

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DMR MUNI 06

Discharge Monitoring Reports & Supplemental Report Forms
(Instructions and helpful hints for their completion)

Please find attached your Discharge Monitoring Report (DMR) and Supplemental Report forms. These forms are used in the self-monitoring program as required by your NPDES permit. You should make copies of these forms for your use. The reporting period is generally a calendar month. Your reports must be received by the 28th day of the following month. Please see that all treatment facility personnel are aware of the permit and DMR form. We seek your assistance in preventing errors and reporting mistakes.

DISCHARGE MONITORING REPORTS (DMRs)

- Inspect the form and contact us immediately if you find errors or omissions. Do not change or add information yourself.
- Complete all blocks where we have listed an entry under Permit Condition. This includes the FREQUENCY OF ANALYSIS and SAMPLE TYPE columns. Do not complete any other blocks.
- Make sure your reports are neat and legible. Submit original DMR, signed in ink to DEP.
- Report in the same significant figures as shown on Effluent Limitations, Monitoring, Recordkeeping, and Reporting Requirements page.
- Report in the same units shown on the DMR.
- List the number of times a particular permit condition has been exceeded under the NO EX column. This would include daily, weekly, and monthly limitations. If there were none for that month, enter zero (0). This does not apply to flow.
- If there was no discharge for a particular outfall, a DMR must still be submitted. Write "NO DISCHARGE" on the FLOW line or on the first parameter line if FLOW is not listed.
- If a particular parameter is conditional on other parameters (such as FLOW or TEMPERATURE), it may not always be reportable. If this is the case, write "NO DISCHARGE" on that parameter line and provide an explanation.
- If you have **quantity** limits (loadings) listed on the DMR, you will need to calculate the **quantity** in lb/day. To do this, use the following formula:

  mg/l (concentration) x **MGD** (Flow) x **8.34 lb/gal = lb/day**

- The monthly average lb/day is the sum of all the daily lb/day results divided by the number of days you sampled. Do not use monthly average flow and monthly average concentration in the above formula.
- All effluent samples taken using approved methods must be recorded on the Supplemental form and reported on the DMR.
- For every day you sample the effluent, you should record the sample result for that day. The discharge flow should be recorded in million gal/day for that day, (a 24-hour period). Use these figures to calculate the lb/day in the formula above.
- Use > (greater than), < (less than) - the method detection limit to report results that are above or below the detection limit and cannot be quantified. Use the method detection limit for calculating loadings if values are less than detection limit.

SUPPLEMENTAL FORMS

A Water/Wastewater calculator is available on the Department's Water/Wastewater information site at:

http://www.dep.state.pa.us/dep/deputate/waterops/hdex.htm

Enter the site and click on: Water/Wastewater Calculators.

Supplemental Form (W)

This form is used for many industrial dischargers and in conjunction with Supplemental Form (S) for some sewage facilities. The column headings in Form (W) are matched to individual permit requirements.

- **Flow.** Report in million gallons (MG). For example: 13,000 gallons = 0.013 MG; 7,500 gallons = 0.0075 MG; 540 gallons = 0.00054 MG; if no flow, indicate by printing "NO FLOW".
- **Total Suspended Solids (TSS).** Report TSS concentration (mg/l) and quantity (lb/day).
- **pH.** Record the pH of the effluent.
- Report effluent parameters at least as often as specified in the permit. Report any influent and process control data as you perform them.
- You may use a computer-generated report for the Supplemental DMR only. Please use the same format as ours. Please contact this office concerning use of your own forms.
- Indicate any outside laboratory use at the bottom of the form. Mark with an **X** if all of the testing is done in-house at your facility.
- Please do **not** send laboratory report forms from your testing laboratory. Do not send your bench sheet or other records, which should be kept at your facility.
- There are a great number of possible column headings for Form (W). Let us know if the abbreviations used are not clear.

We ask that you call us immediately in the event of any equipment breakdown, chemical spill, or shock loading to your influent. Call us also if operational problems result in a failure to achieve your treatment requirements. This includes treatment facility bypasses, pump station failures, and collection system overflows. Violations of effluent limitations for toxic constituents should also be reported. A written report should follow within five (5) days of the event. Refer to your permit for a complete description of the monitoring and reporting responsibilities.

NON-COMPLIANCE DISCHARGE REPORT FORM

Included with the DMR Supplemental Form is a Non-Compliance Discharge Report Form. This form, when properly completed, will suffice as the five-day letter as required in the permit. The following sections must be completed:

1. Describe what was discharged (sludge, raw influent, bypass, etc.) and the date(s) the non-compliance occurred.
2. Circle the applicable stream effects, or describe any unlisted impacts.
3. Explain the cause of the non-compliance. Use the reverse side of the paper or attach additional pages as necessary.
4. Fill in the date(s) and time(s) of the event. Indicate when the event will cease.
5. List here what has been done to reduce, eliminate, and prevent a recurrence of the non-complying discharge.
6. List here any special analyses performed and/or field tests conducted on the discharge and/or stream.
7. When and who did you notify of the non-complying discharge.
8. Your signature and title.

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If you should have any questions, please contact the Water Quality Specialist who inspects your facility. The Specialists can be reached at:

Southcentral Field Office: 717-705-4707

Adams	Fulton	Lancaster (Western)	York
Cumberland	Huntingdon (Eastern)	Lebanon	
Dauphin	Juniata	Mifflin	
Franklin	Lancaster (Eastern)	Perry	

Altoona District Office: 814-946-7290

Bedford Blair Huntingdon (Western)

Reading District Office: 610-916-0100

Berks

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF WATER STANDARDS AND FACILITY REGULATION

ANNUAL INSPECTION FORM FOR NPDES PERMIT FOR DISCHARGES OF STORMWATER ASSOCIATED WITH INDUSTRIAL ACTIVITIES

Who May Use This Form

This form is to be used by permit holders to comply with the: 1) annual inspection requirement when available as an option to monitoring, and 2) Comprehensive Site Compliance Evaluations and Record Keeping in PART C REQUIREMENTS APPLICABLE TO STORMWATER OUTFALLS.

Completing the Form

One form must be completed for each facility or site. Please address all applicable questions and provide documentation to support the responses.

The Annual Inspection shall include visual inspection of all outfalls and a Comprehensive Site Compliance Evaluation. Complete items 10 through 15 for each outfall inspected. Where possible, visual inspection shall identify substances present in the sediment. The Annual Inspection/Certification must identify area(s) contributing pollutant(s) to stormwater discharges(s) and evaluate whether measures to reduce pollutant loadings identified in the PPC Plan are adequate and properly implemented in accordance with terms of the permit or whether additional control measures are necessary. Any deficiencies found during the inspection are to be corrected promptly in accordance with the Comprehensive Site Compliance Evaluations and Record Keeping requirements.

Where to File This Form

When an Annual Inspection is conducted in lieu of monitoring, the permittee shall submit a completed and signed *Annual Inspection Form*, postmarked no later than 28 days after completion of the inspection to the appropriate DEP regional office. All other permittees shall retain the completed and signed form as part of the PPC plan.

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COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF WATER STANDARDS AND FACILITY REGULATION

ANNUAL INSPECTION FORM FOR NPDES PERMIT FOR DISCHARGES OF STORMWATER ASSOCIATED WITH INDUSTRIAL ACTIVITIES

1. Date of Inspection ______________________

3. NPDES Permit #PA ______________________

2. Facility Owner/Operator Name and Address:
____
____
____
Tel: ______________ Fax: ______________

4. Facility Address and Location
Street ______________________
Municipality ______________________ County ______________________

VISUAL INSPECTION

Provide the following information for the storm event

5. Duration ______________________

6. Estimation of rainfall (in inches) † ______________________

† The annual inspection should be conducted after a storm event that is greater than 0.1 inches in magnitude and that occurred at least 72 hours from the previous 0.1 inch storm event.

7. Estimate the time between the previous rain event ______________________

8. Estimate the total volume (in gallons) for each outfall and report it in item 9.
Volume = C x I A,
where C is the runoff coefficient (i.e, 0.9 for paved and 0.5 for unpaved)
I is the rainfall amount (in ft), and
A is the area (square feet) drained to the outfall inspected
(convert from cubic feet to gallons by multiplying by 7.481).

9. Estimate the size of the drainage area (in square feet) for each outfall.

Outfall #	Drainage Area	% Paved	% Unpaved	Volume in gallons

- 1 -

Complete the following information for each outfall inspected (items 10 through 15)

VISUAL INSPECTION OF OUTFALL NUMBER

10. Description of area(s) that drains to outfall. ______

11. Description of stormwater management practices, erosion and sedimentation control practices, and other structural control measures that are in place to control pollutants from running off-site.

______

12. Is there visible flow from the pipe? ☐ Yes ☐ No (Go to number 14) Pipe Dia. (inches) ______
   a. ODOR: Chemical Musty Sewage Rotten Eggs Other ______
   b. COLOR: Clear Red Yellow Brown Other ______
   c. CLARITY: Clear Cloudy Opaque Suspended Solids Other ______
   d. FLOATABLES: Suds Oily Film Garbage Sewage Other ______
   e. DEPOSITS/STAINS: None Oily Sediment Other ______
   f. VEGETATION: None Normal Excessive Inhibited Other ______

13. Is there standing water present? ☐ Yes ☐ No (Go to number 16)
   a. ODOR: Chemical Musty Sewage Rotten Eggs Other ______
   b. COLOR: Clear Red Yellow Brown Other ______
   c. CLARITY: Clear Cloudy Opaque Suspended Solids Other ______
   d. FLOATABLES: Suds Oily Film Garbage Sewage Other ______
   e. DEPOSITS/STAINS: None Oily Sediment Other ______
   f. VEGETATION: None Normal Excessive Inhibited Other ______

14. Is there any evidence of or potential for any pollutant being discharged at this outfall? ☐ Yes ☐ No
   Describe: ______

   If yes, identify substances present in the sediment (if possible). ______

15. Description of corrective measures taken or planned to remove sediments or debris if found during inspection. Please provide a schedule if actions are planned.

______

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COMPREHENSIVE SITE COMPLIANCE EVALUATION

16. Do drainage maps reflect current conditions? ☐ Yes ☐ No

If no, provide your comments.

Comments: ______________________________

17. Based on review of PPC Plan (including Housekeeping Measures), are any changes, corrections or updates necessary? ☐ Yes ☐ No

If yes, provide your comments.

Comments: ______________________________

18. Have you inspected all structural stormwater controls used to implement the PPC Plan to determine if they are adequate? ☐ Yes ☐ No

If no, provide your comments.

Comments: ______________________________

19. Have you inspected the entire site to determine if erosion and sedimentation control measures are adequate? ☐ Yes ☐ No

If no, provide your comments.

Comments: ______________________________

20. Summarize corrective actions/measures completed or planned to correct any deficiencies found as a result of the inspection. Please provide a schedule if actions are planned.

____

21. Signature of Inspector

Name of Inspector: ______________________________

Date Report Prepared: ______________________________

Signature of Inspector: ______________________________

24. Signature of Owner/Operator of Facility

Name/Title Principal Executive Officer Signature Date

I CERTIFY UNDER PENALTY OF LAW THAT I HAVE PERSONALLY EXAMINED AND AM FAMILIAR WITH THE INFORMATION SUBMITTED HEREIN AND BASED ON MY INQUIRY OF THOSE INDIVIDUALS IMMEDIATELY RESPONSIBLE FOR OBTAINING THE INFORMATION. I BELIEVE THE SUBMITTED INFORMATION IS TRUE, ACCURATE AND COMPLETE. I AM AWARE THAT THERE ARE SIGNIFICANT PENALTIES FOR SUBMITTING FALSE INFORMATION INCLUDING THE POSSIBILITY OF FINE AND IMPRISONMENT SEE 18 Pa. C.S. §4904 (relating to unsworn falsification).

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3800-PM-WSFR0083t 9/2005
Additional Information

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF WATER STANDARDS AND FACILITY REGULATION

ADDITIONAL INFORMATION FOR THE REPORTING OF STORMWATER DISCHARGE MONITORING

(This form must be completed and submitted with the DMR form for each outfall sampled)

A. PERMITTEE'S NAME:	OUTFALL/DISCHARGE NO.:
FACILITY/LOCATION:	
B. SAMPLED STORM EVENT	
Provide the date of storm event:	Provide the duration (in hours) of storm event:
Estimate rainfall measurements (in inches) of the storm which generated the sample runoff:	Estimate the duration between the storm event sampled and the end of the previous measurement (greater than 0.1 inch rainfall) storm event:
Drainage area and volume of runoff (1) Paved area _____ square feet x 0.9 (estimated runoff coefficient) x rainfall _____ inches x 0.6234 = _____ gallons (2) Unpaved area _____ square feet x 0.5 (estimated runoff coefficient) x rainfall _____ inches x 0.6234 = _____ gallons Total area ____________________ square feet	Total volume of discharge ____________________ gallons
C. GRAB SAMPLE METHODOLOGY	
If a grab sample during the first 30 minutes of the discharge was impracticable, and the sample was instead taken during the first hour of the discharge, describe the circumstances:	
D. SAMPLE WAIVER	
If samples could not be collected due to adverse climatic conditions, describe why samples could not be collected. Attach available documentation of the event.	
If monitoring data submitted is being used to represent other substantially identical outfalls, summarize on a drainage area and volume of runoff under item B. above for each outfall.	

State + Local

DEBEVOISE & LIBERMAN
700 SHOREHAM BUILDING
806 15TH STREET, N.W.
WASHINGTON, D.C. 20005
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DONALD B. MYERS
NICHOLAS S. REYNOLDS
PATRICIA CONNELL SHAKOW

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PAUL T. NOWAK, JR.
DONALD K. DANKNER
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MATTHEW B. VAN HOOK
KENNETH G. HURWITZ
J. DANIEL BERRY*

THOMAS M. DEBEVOISE
COUNSEL

*ADMITTED IN MD. ONLY

December 5, 1977

The Honorable Thomas M. Burke
Environmental Hearing Board
Blackstone Building
First Floor Annex
112 Market Street
Harrisburg, Pennsylvania 17101

Re: Metropolitan Edison Company v. Commonwealth of Pennsylvania, Department of Environmental Resources Docket No. 77-076-B

Dear Mr. Burke:

Enclosed please find a "Request to Withdraw Appeal" in the above-captioned matter. Attached as an Exhibit to the request is a copy of the revised Section 401 Certification reflecting the agreement reached between the parties and which resolves the outstanding issues which are the subject of the above appeal.

Very truly yours,

John P Proctor

John P. Proctor
Attorney for
Metropolitan Edison Company

JPP/ssg
cc: w/Encl.
Eugene E. Dice, Esq.

COMMONWEALTH OF PENNSYLVANIA
Before The
ENVIRONMENTAL HEARING BOARD

METROPOLITAN EDISON COMPANY v. DEPARTMENT OF ENVIRONMENTAL RESOURCES	))))))	EHB Docket #77-076-B

REQUEST TO WITHDRAW APPEAL

AND NOW COMES John P. Proctor, and Debevoise & Liberman, attorneys for Metropolitan Edison Company in the above-captioned docket, and states and requests as set forth hereafter:

1. Attached hereto is a revised Section 401 Certification executed by Frederick A. Marrocco, Chief, Planning Section, Harrisburg Regional Office, on behalf of the Department of Environmental Resources, reflecting the agreement reached between the parties with respect to Metropolitan Edison Company's Three Mile Island Nuclear Generating Station which is the subject of the instant appeal.

2. On the basis of the document referenced in paragraph 1 above and attached hereto, Metropolitan Edison Company requests that its appeal in the above-captioned docket number be marked as withdrawn.

Respectfully submitted,

John P. Proctor

John P. Proctor

63.0016.0001.0005
63.0009.0000

Copies to
3 cc GJT
1 cc RMK
~~1 cc L3~~
1 cc JGH
~~1 cc G.P.Miller~~
1cc chrono
Orig. - file

Room 1002 Health & Welfare Building
Harrisburg, Pennsylvania 17120
(717) 787-9665
November 9, 1977

Mr. Bruce P. Smith
Permits Branch
U.S. Environmental Protection Agency
Sixth and Walnut Streets
Philadelphia, Pennsylvania 19106

EPA Application PA0009920
Metropolitan Edison Company
Three Mile Island Nuclear Station
Londonderry Township
Dauphin County

Dear Mr. Smith:

The Commonwealth of Pennsylvania hereby certifies to the following and thus invalidates all past certifications:

1. The Amendments Nos. 1 and 2 issued 12/29/76 and 5/20/77 respectively for the National Pollutant Discharge Elimination System Permit for subject discharger were forwarded to the Commonwealth of Pennsylvania pursuant to the provisions of Section 401 of the Federal Water Pollution Control Act Amendments of 1972.

2. The effluent limitations and other limitations, and monitoring requirements as proposed in the tentative permit amendments submitted for our review:

   a. Assure that the applicant will comply with applicable effluent limitations under Section 301 or 302, standards of performance under Section 306, or prohibition, effluent standards, or pre-treatment standards under Section 307 of the FWPCA Amendments of 1972 where they are presently applicable;

   b. Shall become a condition of a Federal NPDES permit pursuant to Section 402 of the FWPCA Amendments.

3. This certification is subject to the following conditions:

   a. That the Permittee complies with Pennsylvania's Clean Streams Law.

   b. That the Permittee complies with Industrial Waste Permits 2270204 and 2272202, and Sewerage Permit 2275419 issued by the Department of Environmental Resources.

NPDES PA0009920 -2- November 9, 1977
Metropolitan Edison Company

c. The following effluent limitations should be imposed:

1. Discharge 101 – Effluent of sewage treatment facilities

Total phosphorus shall not exceed 2 mg/l on an average basis, nor 4 mg/l at any time.

2. Discharge 001 – Combined Mechanical Draft Cooling Tower Blowdown.

a. The permittees shall at all times maintain in good working order and operate the Mechanical Draft Cooling Towers (MDCT's) as efficiently as possible so as to minimize temperature differential between ambient river temperature and the temperature of the discharge; provided, however, the MDCT's may be shut down when in the judgment of the responsible TMINS personnel a combination of atmospheric conditions and river temperature may exist which causes the waste water to be heated as it passes through the MDCT's or ice formation is observed to occur within the MDCT's.

b. The temperature of the discharge shall never exceed a maximum of 87° F, except when the ambient river temperature exceeds 87° F, in which case, the discharge temperature shall not exceed the ambient river temperature; the temperature of the discharge shall not change by more than 5° F during any one hour period.

Ambient river temperature is the temperature of the river upstream of the heated waste discharge. The ambient temperature sampling point should be unaffected by any sources of waste heat. The temperature of the intake water will be considered as ambient river temperature so long as the intake water is unaffected by TMI's or any other nearby heated water discharge.

c. The following temperature limitations shall never be exceeded:

1. During the period November 1 through April 30, the temperature of the discharge shall not exceed 12° F above ambient river temperature.

2. During the period May 1 through October 31, the temperature of the discharge shall not exceed 7° F above ambient river temperature.

NPDES PA0009920 -3- November 9, 1977
Metropolitan Edison Company

3. During plant cooldown operations the temperature of the discharge shall not exceed 12° F above ambient river temperature.

d. At no time shall the discharge exceed the rate of 150 million gallons per day.

e. The Chief of the Operations Section of the Harrisburg Regional Office of the Bureau of Water Quality Management shall be advised by telephone within 24 hours when the MDCT's are shut down for reasons other than those specified in condition 2(a) above and again when tower operation is resumed; shall be notified within 24 hours when the discharge limitations specified in paragraph 2(c) above are exceeded and again when the discharge is in compliance with such limitations; and shall be notified, at least thirty (30) days in advance, whenever possible of all scheduled plant cooldown operations.

f. Within two years after both nuclear reactor units are in commercial operation, the Metropolitan-Edison Company will collect and submit to the Department of Environmental Resources stream data which accurately defines the thermal plume or zone of impact from the TMINS heated waste discharge. As a minimum, thermal plume mapping data collected to meet the Nuclear Regulatory Commission's requirements shall be submitted to the Pennsylvania Department of Environmental Resources.

g. That the Permittee submit to the Pennsylvania Department of Environmental Resources within ninety (90) days of issuance of Amendment No. 1 to the NPDES permit, an application for a new Pennsylvania Water Quality Management permit for the facilities associated with the thermal component of discharge 001.

4. We certify that the final effluent limitations contained herein and in the attached NPDES permit, to the extent that they are not inconsistent with the limitations herein, are those efflnent limitations which are required to achieve the federally approved water quality criteria for the receiving stream. We also certify that the compliance schedule therein is reasonable. We do not certify that the applicant for an NPDES permit is now in compliance with our effluent limitations or permit requirements established pursuant to the Clean Streams Law, Act of June 22, 1937, P.L. 1987, as amended, 35 P.S. 691.1 or that such source is discharging in compliance with the terms or conditions of a state permit. Nor do we certify that by attaining the interim standards contained in the NPDES permit that such source will be in compliance with the aforementioned Clean Streams Law and the Rules

NPDES PA0009920 -4- November 9, 1977
Metropolitan Edison Company

and Regulations thereunder. By certifying the final effluent standards and the schedule for compliance to be contained in the NPDES permit, we do not waive our right to prosecute either civilly or criminally all past, present and future violations of our Clean Streams Law and the Rules and Regulations thereunder. Nor do we waive our right to modify final effluent requirements as is necessary to comply with Pennsylvania Law.

5. This certification by the Department may be appealed to the Environmental Hearing Board, First Floor Annex, Blackstone Building, 112 Market Street, Harrisburg, PA (717) 787-3483, by any aggrieved person pursuant to the Act of December 3, 1970, P.L. 834, 71 Pa. Stat. Anno. §510-1 et seq. and the Administrative Agency Law, the Act of June 13, 1945, P.L. 1388, as amended 71 Pa. Stat. Anno. §1710.1 et seq. Appeals must be filed with the Environmental Hearing Board within thirty (30) days of service of this certification unless the appropriate statute provides a different time period. Copies of the appeal form and the Department's regulations governing practice and procedure before the Board may be obtained from the Board.

Very truly yours,

Frederick A. Marrocco

Frederick A. Marrocco, Chief
Planning Section
Harrisburg Regional Office

FAM:kew

cc: Metropolitan Edison Company

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COMMONWEALTH OF PENNSYLVANIA

P. O. BOX 2351
HARRISBURG 17105

DEPARTMENT OF ENVIRONMENTAL RESOURCES

August 23, 1971

Mr. John G. Miller
Vice President and Chief Engineer
Metropolitan Edison Company
P. O. Box 542
Reading, Pennsylvania 19603

Dear Mr. Miller:

This is in response to your letters of August 31, 1970 and December 21, 1970 requesting certification of reasonable assurance that the Three Mile Island Nuclear Station Units 1 and 2 will not violate applicable water quality standards. We understand that the certification is requested by Metropolitan Edison Company on its own behalf and on behalf of the Jersey Central Power & Light Company and Pennsylvania Electric Company as co-owners and tenants in common.

The following information is provided in accordance with the format included in 18 CFR, Part 615.2, as published in the May 8, 1971 Federal Register.

(a) The applicant is Metropolitan Edison Company, Reading, Pennsylvania, 19603, on its own behalf and on behalf of Jersey Central Power & Light Company and Pennsylvania Electric Company as tenants in common.

(b) The facility is a nuclear powered electric generating station which will result in the production, treatment and discharge of heated waters, water treatment wastes and radioactive wastes. Details on the operation

ATTACHMENT E

Mr. John G. Miller - 2 - August 23, 1971

of the facility, including the characteristics of raw and treated wastes and ~~the locations of the~~ discharges, are contained in Application No. 22-70-2-04 submitted by the Metropolitan Edison Company. The information in said Application has been examined by the Department of Environmental Resources and the information therein is sufficient to permit the undersigned to make the statement in subparagraph (c) below.

(c) There is reasonable assurance that the proposed activity will be conducted in a manner that will not violate applicable water quality standards.

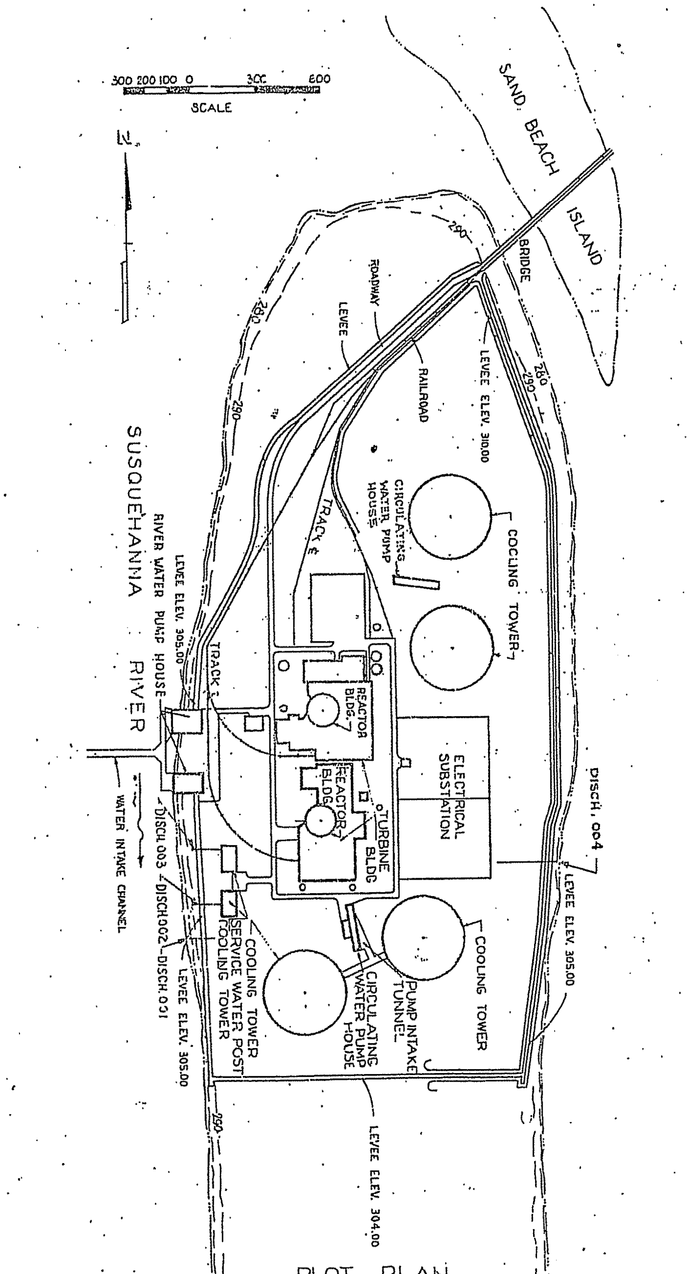
(d) Permit No. 22-70-2-04 issued to the Metropolitan Edison Company contains the conditions applicable to the discharge of wastes from the Three Mile Island Nuclear Station, Units 1 and 2.

Very truly yours,

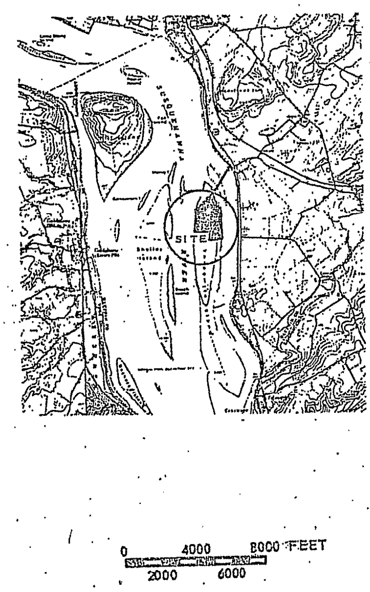
Donald A. Lazarchik

Donald A. Lazarchik
Acting Director
Division of Industrial Wastes

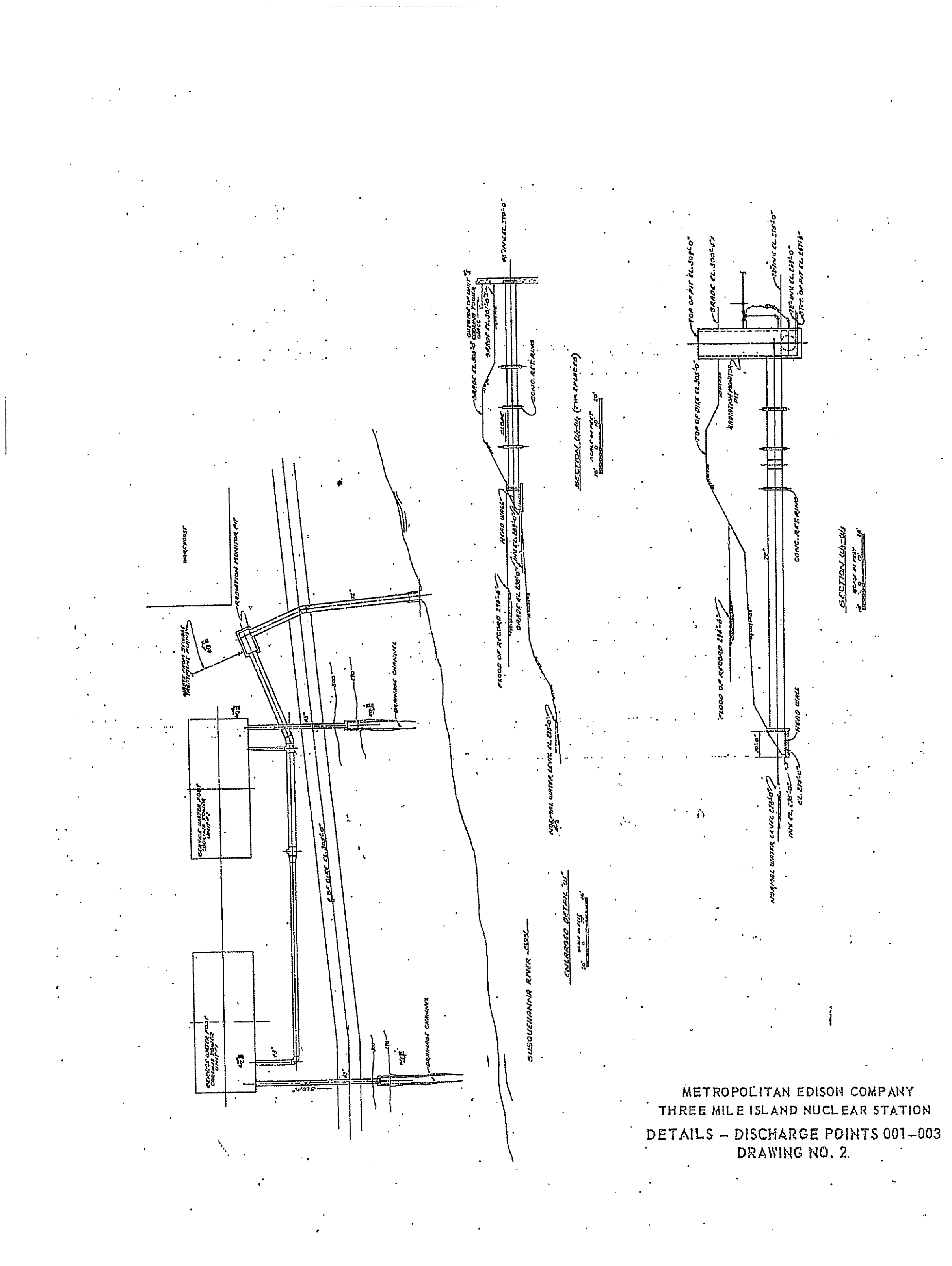
ATTACHMENT E



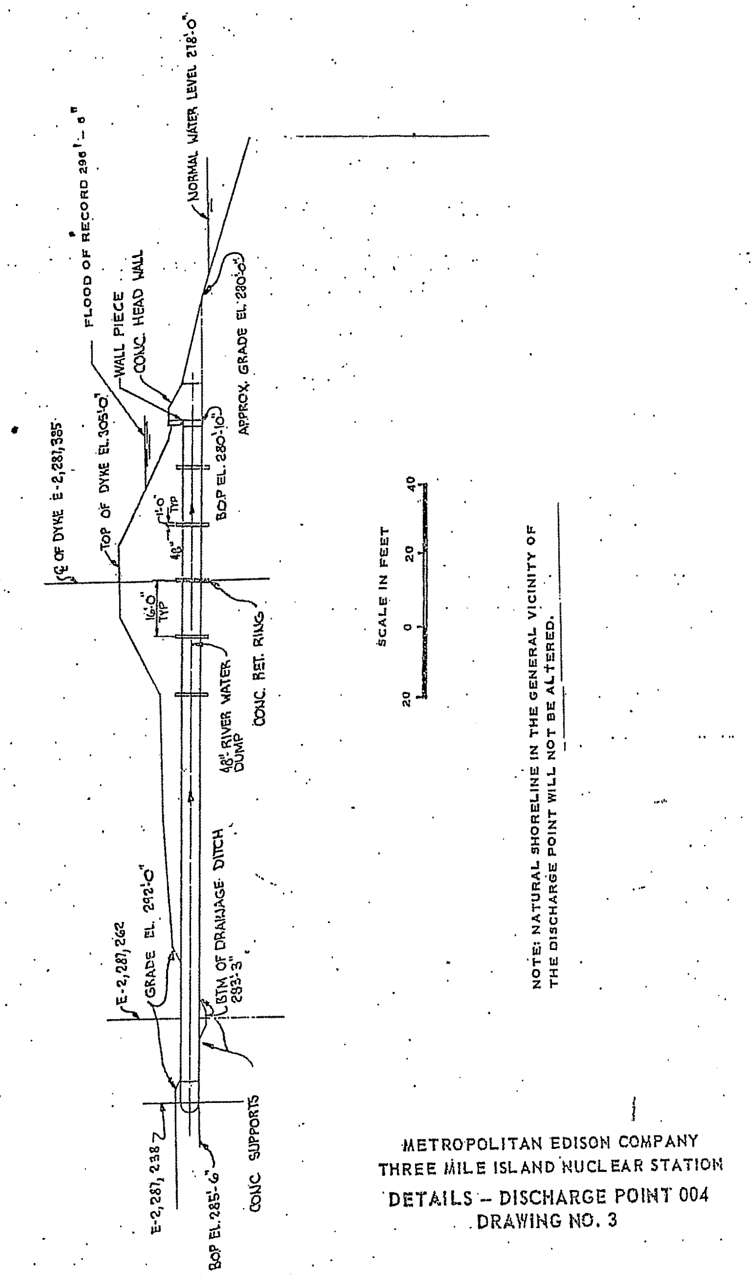
PLOT PLAN



METROPOLITAN EDISON COMPANY
THREE MILE ISLAND NUCLEAR STATION
DISCHARGE LOCATIONS
DRAWING NO. 1



METROPOLITAN EDISON COMPANY
THREE MILE ISLAND NUCLEAR STATION
DETAILS – DISCHARGE POINTS 001–003
DRAWING NO. 2


FLOOD OF RECORD 298'-8"
NORMAL WATER LEVEL 278'-0"
WALL PIECE
CONC. HEAD WALL
APPROX. GRADE EL. 280'-0"
℄ OF DYKE E-2,281,385
TOP OF DYKE EL. 305'-0"
BOP EL. 280'-10"
11'-0" TYP
48"
16'-0" TYP
CONC. RET. RING
48" RIVER WATER DUMP
E-2,281,262
GRADE EL. 292'-0"
BTM OF DRAINAGE DITCH 293'-3"
E-2,281,238
BOP EL. 285'-6"
CONC. SUPPORTS
SCALE IN FEET
20 0 20 40
NOTE: NATURAL SHORELINE IN THE GENERAL VICINITY OF THE DISCHARGE POINT WILL NOT BE ALTERED.
METROPOLITAN EDISON COMPANY
THREE MILE ISLAND NUCLEAR STATION
DETAILS – DISCHARGE POINT 004
DRAWING NO. 3

Appendix C

Special Status Species Correspondence

Three Mile Island Nuclear Station Unit 1 Environmental Report

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AmerGen
An Exelon Company

Michael P. Gallagher, PE
Vice President
License Renewal Projects

Telephone 610.765.5958
www.exeloncorp.com
michaelp.gallagher@exeloncorp.com

AmerGen
200 Exelon Way
KSA/2-E
Kennett Square, PA 19348

May 22, 2007

Ms. Chris Firestone, Native Plant Program Manager
Pennsylvania Department of Conservation and Natural Resources
Bureau of Forestry (Plant Program)
Forest Advisory Services
P O Box 8552
Harrisburg, PA 17105-1673

SUBJECT: Three Mile Island Nuclear Station Unit 1 License Renewal. Request for information on state-listed threatened and endangered species and important habitats (plants).

Dear Ms. Firestone:

AmerGen is preparing an application for the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for Three Mile Island Nuclear Station Unit 1 (TMI-1). The current operating license for TMI-1 will expire in 2014. The renewal term would be for an additional 20 years beyond the original license expiration date. As part of the license renewal process, the NRC requires license applicants to "assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10 CFR 51.53). The NRC will also request an informal consultation with your office at a later date under Section 7 of the Endangered Species Act. By contacting you early in the application process, we hope to identify any issues that we need to address or any information that we should provide to your office to expedite the NRC consultation.

TMI-1 is located on Three Mile Island, in the Susquehanna River, in the Londonderry Township of Dauphin County, Pennsylvania. AmerGen began operations of TMI-1 after its purchase of the facility in 1999. The transmission lines associated with the facility are owned and operated by First Energy Corporation. Four transmission lines connect the station to the regional grid, and are thus relevant to license renewal. The *Final Environmental Statement* for operation prepared in 1972 by the U.S. Atomic Energy Commission identified three 230-kilovolt (kV) transmission lines that were built to connect Unit 1 to the electric grid. Two of these 230-kV lines span northeast approximately 1.4 miles in the same corridor connecting the plant with the substation at Middletown Junction. The third 230-kV line extends for 4.1 miles to the western side of the Susquehanna River connecting with the Jackson Substation near Cly. Subsequent to the publication of the *Final Environmental Statement*, a fourth 230-kV line was also constructed that extends 0.7 miles southeast to the TMI-1 500-kV substation. All of the transmission lines are within 150-foot wide corridors

May 22, 2007
Page 2 of 2

and are primarily in agricultural or pasture lands that continue to be cultivated. Included is a map of the transmission line system layered over the USGS topographic maps surrounding the TMI-1 facility (see Figure 1). Pennsylvania counties crossed by the transmission lines include Lancaster, Dauphin, and York. AmerGen is not aware of any state-listed plant species at TMI or along the TMI-associated transmission lines, with the exception of the American holly (*Ilex opaca*), which was identified on TMI as part of Exelon's commitment to the environment under the Wildlife Habitat Council program.

A review of the Pennsylvania Natural Heritage Program web site for state-listed endangered or threatened species indicates that numerous state-listed plant species have been recorded in the counties crossed by the transmission lines; however, a large percentage of these plants have been recorded in Lancaster County and TMI-1 transmission lines only cross a very small section of Lancaster County in the extreme western corner (see Figure 1). First Energy maintains the transmission lines and ensures adherence to regulatory requirements regarding sensitive areas that could contain threatened or endangered species as well as state-listed species and works closely with your department to ensure protection of these sensitive areas.

AmerGen is committed to the conservation of significant natural habitats and protected species, and expects that operation of TMI-1, including maintenance of the identified transmission lines, through the license renewal period (an additional 20 years) would not adversely affect any listed species. AmerGen has no plans to alter current operations over the license renewal period. Any maintenance activities necessary to support license renewal would be limited to previously disturbed areas.

In addition, AmerGen plans to replace the existing steam generators with newer models in the fall of 2009. These replacement activities would occur within the existing Unit 1 containment structure. A 6,000 square foot dedicated storage facility would be built within the existing industrial footprint of the site to house the old steam generators. No additional land disturbance is anticipated in support of license renewal.

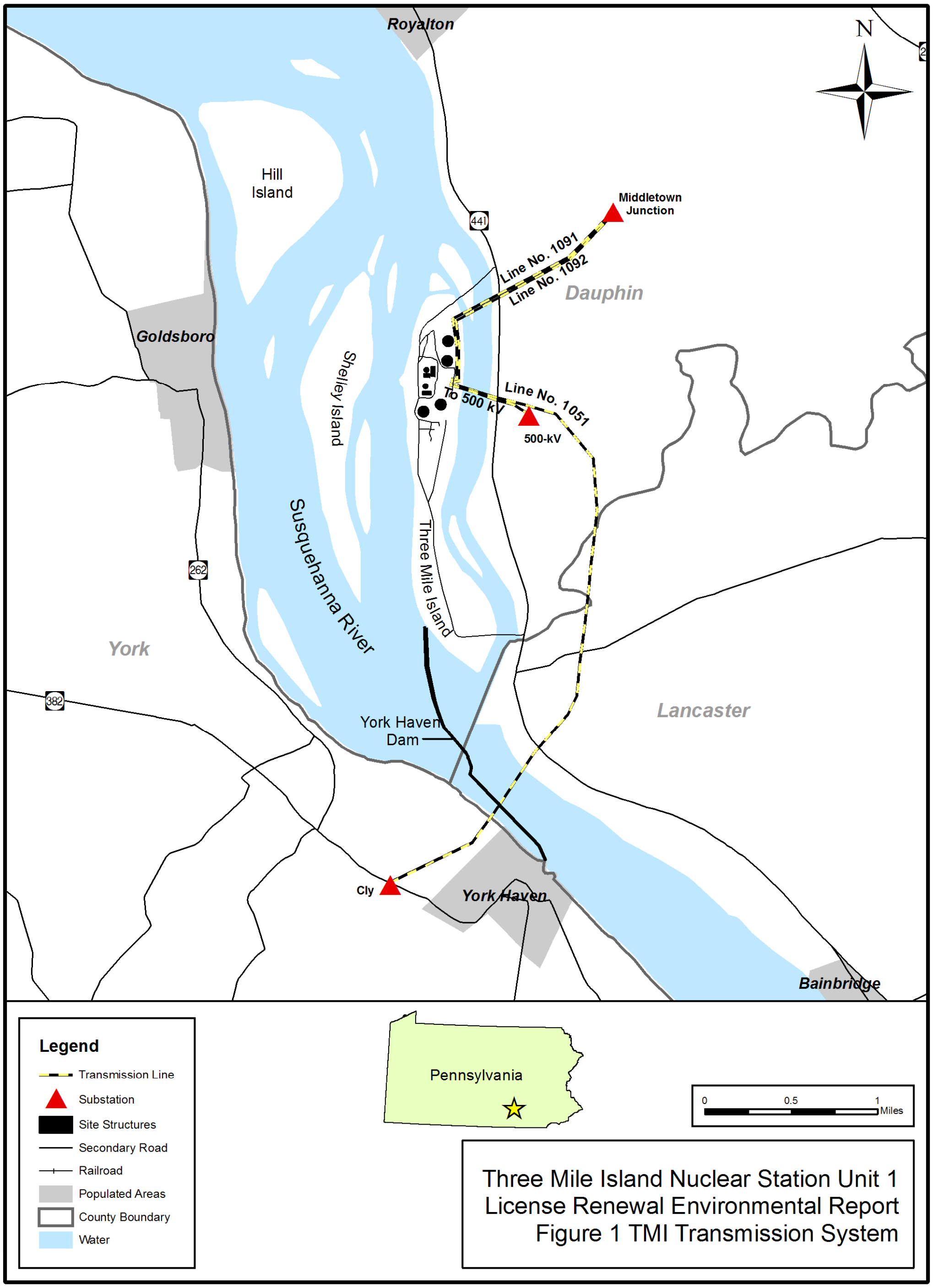
Please call Fred Polaski (610) 765-5935 if you have any questions or require any additional information. After your review, we would appreciate receiving your input by August 17, 2007, detailing any concerns you may have about any listed species or critical habitat in the area, or confirming AmerGen's conclusion that operation of TMI-1 over the license renewal term would have no effect on any threatened or endangered species. This will enable us to meet our application preparation schedule. AmerGen will include a copy of this letter and your response in the Environmental Report that will be submitted to the NRC as part of the TMI-1 license renewal application.

Sincerely,
Michael P. Gallagher

Michael P. Gallagher

Enclosures: Figure 1, TMI-1 Transmission System Map

Figure 1 - TMI-1, Transmission System Map
Page 1 of 1



Three Mile Island Nuclear Station Unit 1
License Renewal Environmental Report
Figure 1 TMI Transmission System

DCNR Pennsylvania Department of Conservation and Natural Resources

Bureau of Forestry June 25, 2007

Michael P. Gallagher
AmerGen
200 Exelon Way
KSA/2-E
Kennett Square, PA 19348

Pennsylvania Natural Diversity Inventory Review, PNDI Number **19248**
Three Mile Island Unit 1 License Renewal Species of Special Concern 1-mile radius
Dauphin & Lancaster Counties

Dear Mr. Gallagher,

This responds to your request about a Pennsylvania Natural Diversity Inventory (PNDI) ER Tool "Potential Impact" or a species of special concern impact review. We screened this project for potential impacts to species and resources of special concern under the Department of Conservation and Natural Resources' responsibility, which includes plants, natural communities, terrestrial invertebrates and geologic features only.

PNDI records indicate that species and communities of special concern under DCNR's jurisdiction are known to occur in the vicinity of the above-mentioned project. **Please see the attached list for species found in the project area. If any earth disturbance is planned or more detailed project information becomes available, please submit this project to our office for further review of potential impacts to the attached species list.**

This response represents the most up-to-date summary of the PNDI data files and is good for one (1) year from the date of this letter. An absence of recorded information does not necessarily imply actual conditions on-site. A field survey of any site may reveal previously unreported populations. Should project plans change or additional information on listed or proposed species become available, this determination may be reconsidered.

This finding applies to impacts to plants, natural communities, terrestrial invertebrates and geologic features only. To complete your review of state and federally-listed species of special concern, please be sure the U.S. Fish and Wildlife Service, the PA Game Commission and the Fish and Boat Commission has been contacted regarding this project either directly or by performing a search with the online PNDI ER Tool found at www.naturalheritage.state.pa.us.

Rebecca H. Bowen

______________________Rebecca H. Bowen, Environmental Review Specialist
DCNR/BOF/PNDI, PO Box 8552, Harrisburg, PA 17105 ~ Ph: 717-772-0258 ~ F: 717-772-0271 ~ c-rbowen@state.pa.us

Stewardship Partnership Service

DCNR Pennsylvania Department of Conservation and Natural Resources

Bureau of Forestry

June 25, 2007

Pennsylvania Natural Diversity Inventory Review, PNDI Number 19248
Three Mile Island Unit 1 License Renewal Species of Special Concern 1-mile radius
Dauphin & Lancaster Counties

Plant Species of Special Concern

Scientific Name	Common Name	Current Status	Proposed Status	Habitat	Flowering time
Boltonia asteroides	Aster-like Boltonia	PA Endangered	PA Endangered	rocky shores and exposed rocky river beds	flowers July-Oct
Carex shortiana	Sedge	Not Protected	PA Rare	calcareous wet meadows and swamps and rich woods	
Eleocharis compressa	Flat-stemmed Spike-rush	PA Endangered	PA Endangered	wet, sandy ground and river banks	
Ellisia nyctelea	Ellisia	PA Threatened	PA Threatened	damp, shady banks and rich alluvial woods	flowers in May

Butterfly Species of Special Concern

Scientific Name	Common Name	Global Rank	State Rank	Habitat	Larval Host
Lycaena hyllus	Bronze Copper	Globally Secure	Currently unrankable due to lack of information or due to substantially conflicting information about status or trends.	Low wet meadows / marshes, especially in river flood plains. Very large, floppy-flying copper.	Water dock (*Rumex orbiculatus*) and curled dock (*Rumex crispus*)

Geologic Features of Special Concern

Erosional Remnant made up of a series of large potholes in diabase in the bed of the Susquehanna from the Triassic Age is known to exist where the transmission lines cross the river towards York Haven.

Communities of Special Concern

There is also a Riverside Outcrop Community in the vicinity. This community is characterized by semi-permanently or seasonally flooded vegetation of the riverbed, banks and islands. Please find more information on this community type attached.

Stewardship Partnership Service

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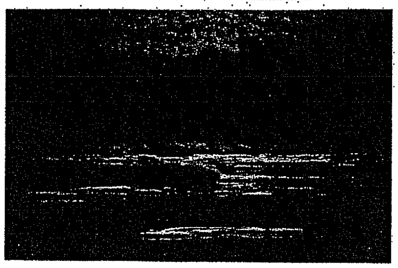
Community Complexes continued. . .

From: Fike, 1999. Terrestrial + Palustrine Plant Communities of PA.



River bed - bank - flood plain complex. Susquehanna River, Dauphin County. Photograph by Jean Fike.

RIVER BED - BANK - FLOODPLAIN COMPLEX

Community types that characterize this complex*:

Sycamore - (river birch) - box elder floodplain forest
Silver maple floodplain forest
Red maple - elm - willow floodplain swamp
River birch - sycamore floodplain scrub
Black willow scrub/shrub wetland
Riverside ice scour community
Big bluestem - Indian grass river grassland
Water-willow - smartweed riverbed community

(***Note:** Examples of this complex will not usually contain all of the community types listed.)

Description:
This complex describes persistent emergent vegetation growing in or along rivers. It includes semi-permanently/seasonally flooded vegetation of the riverbed, banks and islands as well as temporarily flooded and saturated floodplain communities. This landscape is organized by severity and frequency of flooding, ice scour, direction of flow, and differences in substrate. Community types that are inundated for much of the growing season in most years are dominated by herbaceous vegetation (e.g. *Apocynum cannabinum, Justicia americana, Eleocharis* spp., *Cyperus* spp., *Polygonum* spp., *Bidens* spp.). Areas with less extensive periods of inundation, which are scoured by river ice in some years, are dominated by woody vegetation (e.g. *Betula nigra, Salix nigra, Platanus occidentalis*), which is maintained in an early successional stage by ice scour and flooding. Areas that are not subject to ice scour and are periodically inundated but remain dry for the majority of the year, support forest vegetation with a mixture of upland and wetland species. Floodplain sites where floodwaters are retained on site for longer periods of time or where additional hydrologic sources are present may support almost entirely wetland vegetation. Differences in disturbance regime, substrate, and hydrologic regime produces the great structural, community, and species diversity associated with this complex.

The community type with the longest typical period of inundation is the "Water-willow - smartweed riverbed community." This community type occurs on alluvium, mud or on riverbed rock where soil accumulates in crevices. It remains inundated for most of the year, but may become exposed during dry periods. In areas subject to flooding of lesser frequency and duration but still subject to ice scour, a variety of woody and herbaceous community types occur. On sand and gravel bars, and occasionally on rock outcrops with sand and silt accumulating in cracks in the rock, a tall grassland community, with or without scattered woody plants, the "Big bluestem - Indian grass river grassland" may be found. The "Riverside ice scour community" occurs on rock outcrops, and is characterized by a mixture of herbaceous and woody plants. The frequency and severity of ice scour and flooding in these two communities maintain their open aspect.

Along the riverbanks and on larger islands, where the disturbance regime is somewhat less severe, two woody community types—the "River birch - sycamore floodplain scrub" and the "Black willow scrub/shrub wetland" frequently occur. These two communities exist on a continuum with the "Big bluestem - Indian grass river grassland." In areas where disturbance is intermediate, the vegetation may be intermediate between types. Likewise, depending on flood and scour severity in recent years, woody plants may become established on, or be removed from a given site. This is a dynamic system, driven primarily by river levels.

In areas subject to still less prolonged and less frequent flooding, and not generally subject to ice scour, floodplain forests usually occur. The "Silver maple floodplain forest" and the "Sycamore - (river birch) - box elder floodplain forest" are dry throughout most of the year, but receive at least intermittent flooding. The "Red maple - elm - willow floodplain swamp" may be flooded with a frequency similar to that of the other two floodplain forest types, but it typically occurs in depressions, old oxbows, or behind natural levees. The landscape position of this community type prevents floodwaters from draining rapidly, and water is retained on the site for prolonged periods. These wetlands may also receive groundwater enrichment and/or surface water from adjacent uplands.

More information is needed to describe in greater detail the hydrology, landscape position and successional dynamics of the community types in this complex.

Range: Entire state, associated with major river systems.

Crosswalk: This complex is equivalent to a combination of Smith's (1991) "Floodplain Swamp," "River Gravel Community," and "Riverside Outcrop / Cliff Community" types.

Selected references: Cowardin et al. 1979, PNDI Field forms, Smith 1991.

72

AmerGen
An Exelon Company

Michael P. Gallagher, PE
Vice President
License Renewal Projects

Telephone 610.765.5958
www.exeloncorp.com
michaelp.gallagher@exeloncorp.com

AmerGen
200 Exelon Way
KSA/2-E
Kennett Square, PA 19348

May 22, 2007

Mr. Christopher Urban
Chief of Natural Diversity Section
Pennsylvania Fish and Boat Commission
450 Robinson Lane
Bellefonte, PA 16823-9620

SUBJECT: Three Mile Island Nuclear Station Unit 1 License Renewal. Request for information on state-listed threatened and endangered species and important habitats (fish, reptiles amphibians, and invertebrates).

Dear Mr. Urban:

AmerGen is preparing an application for the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for Three Mile Island Nuclear Station Unit 1 (TMI-1). The current operating license for TMI-1 will expire in 2014. The renewal term would be for an additional 20 years beyond the original license expiration date. As part of the license renewal process, the NRC requires license applicants to "assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10 CFR 51.53). The NRC will also request an informal consultation with your office at a later date under Section 7 of the Endangered Species Act. By contacting you early in the application process, we hope to identify any issues that we need to address or any information that we should provide to your office to expedite the NRC consultation.

TMI-1 is located on Three Mile Island, in the Susquehanna River, in the Londonderry Township of Dauphin County, Pennsylvania. AmerGen began operations of TMI-1 after its purchase of the facility in 1999. The transmission lines associated with the facility are owned and operated by First Energy Corporation. Four transmission lines connect the station to the regional grid, and are thus relevant to license renewal. The *Final Environmental Statement* for operation prepared in 1972 by the U.S. Atomic Energy Commission identified three 230-kilovolt (kV) transmission lines that were built to connect Unit 1 to the electric grid. Two of these 230-kV lines span northeast approximately 1.4 miles in the same corridor connecting the plant with the substation at Middletown Junction. The third 230-kV line extends for 4.1 miles to the western side of the Susquehanna River connecting with the Jackson Substation near Cly. Subsequent to the publication of the *Final Environmental Statement*, a fourth 230-kV line was also constructed that extends 0.7 miles southeast to the TMI-1 500-kV substation. All of the transmission lines are within 150-foot wide corridors

May 22, 2007
Page 2 of 2

and are primarily in agricultural or pasture lands that continue to be cultivated. Included is a map of the transmission line system layered over the USGS topographic maps surrounding the TMI-1 facility (see Figure 1). Pennsylvania counties crossed by the transmission lines include Lancaster, Dauphin, and York. Based on our direct observations, a review of TMI-1 records, and a review of the Pennsylvania Natural Heritage Program web site for state-listed endangered or threatened species, AmerGen believes that a complete list of state-listed threatened and endangered species has been compiled. This species list includes: three reptiles (Bog turtle, *Clemmys muhlenbergii*, Rough green snake, *Opheodrys aestivus*, and the Redbelly turtle, *Pseudemys rubriventris*); one fish (Black bullhead, *Ameiurus melas*) and one invertebrate (Dwarf wedgemussel, *Alasmidonta heterodon*), that could occur in the counties crossed by the transmission lines.

AmerGen is committed to the conservation of significant natural habitats and protected species, and expects that operation of TMI-1, including maintenance of the identified transmission lines, through the license renewal period (an additional 20 years) would not adversely affect any listed species. AmerGen has no plans to alter current operations over the license renewal period. Any maintenance activities necessary to support license renewal would be limited to previously disturbed areas.

In addition, AmerGen plans to replace the existing steam generators with newer models in the fall of 2009. These replacement activities would occur within the existing Unit 1 containment structure. A 6,000 square foot dedicated storage facility would be built within the existing industrial footprint of the site to house the old steam generators. No additional land disturbance is anticipated in support of license renewal.

Please call Fred Polaski (610) 765-5935 if you have any questions or require any additional information. After your review, we would appreciate receiving your input by August 17, 2007, detailing any concerns you may have about any listed species or critical habitat in the area, or confirming AmerGen's conclusion that operation of TMI-1 over the license renewal term would have no effect on any threatened or endangered species. This will enable us to meet our application preparation schedule. AmerGen will include a copy of this letter and your response in the Environmental Report that will be submitted to the NRC as part of the TMI-1 license renewal application.

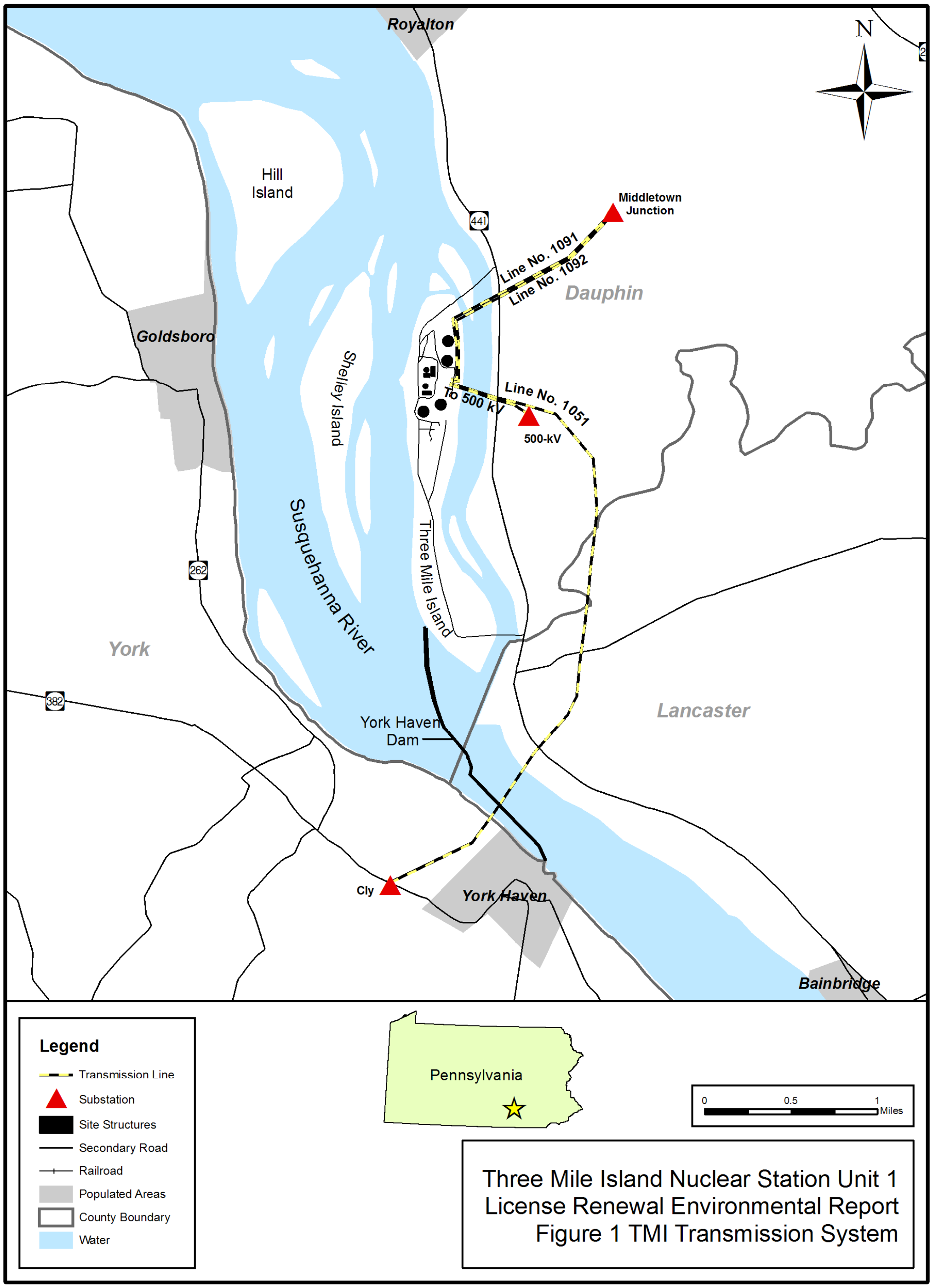
Sincerely,

Michael P. Gallagher

Michael P. Gallagher

Enclosures: Figure 1, TMI-1 Transmission System Map

Figure 1 - TMI-1, Transmission System Map
Page 1 of 1



Three Mile Island Nuclear Station Unit 1
License Renewal Environmental Report
Figure 1 TMI Transmission System

PENNSYLVANIA FISH & BOAT COMMISSION
established 1866

Pennsylvania Fish & Boat Commission

Division of Environmental Services
Natural Diversity Section
450 Robinson Lane
Bellefonte, PA 16823-9620
(814) 359-5237 Fax: (814) 359-5175

June 7, 2007

mP 6.11.07

IN REPLY REFER TO
SIR # 25706

MICHAEL GALLAGHER
AMERGEN
200 EXELON WAY
KSA/2-E
KENNETT SQUARE, PA 19348

RE: Species Impact Review (SIR) - Rare, Candidate, Threatened and Endangered Species
THREE MILE ISLAND NUCLEAR STATION UNIT 1
LONDONDERRY Township/Borough, DAUPHIN County, Pennsylvania

This responds to your inquiry about a Pennsylvania Natural Diversity Inventory (PNDI) Internet Database search "potential conflict" or a threatened and endangered species impact review. These projects are screened for potential conflicts with rare, candidate, threatened or endangered species under Pennsylvania Fish & Boat Commission jurisdiction (fish, reptiles, amphibians, aquatic invertebrates only) using the Pennsylvania Natural Diversity Inventory (PNDI) database and our own files. These species of special concern are listed under the Endangered Species Act of 1973, the Wild Resource Conservation Act, and the Pennsylvania Fish & Boat Code (Chapter 75), or the Wildlife Code. The absence of recorded information from our files does not necessarily imply actual conditions on site. Future field investigations could alter this determination. The information contained in our files is routinely updated. A Species Impact Review is valid for one year only.

_X_ *NO ADVERSE IMPACTS EXPECTED FROM THE PROPOSED PROJECT*

___ Except for occasional transient species, rare, candidate, threatened or endangered species under our jurisdiction are not known to exist in the vicinity of the project area. Therefore, no biological assessment or further consultation regarding rare species is needed with the Commission. Should project plans change, or if additional information on listed or proposed species becomes available, this determination may be reconsidered.

_X_ An element occurrence of a rare, candidate, threatened, or endangered species under our jurisdiction is known from the vicinity of the proposed project. However, given the nature of the proposed project, the immediate location, or the current status of the nearby element occurrence(s), no adverse impacts are expected to the species of special concern.

If you have any questions regarding this review, please contact the biologist indicated below:

___	Jeff Schmid	814-359-5236	___	Tina Walther	814-359-5186
_X_	Nevin Welte	814-359-5234	___	Bob Morgan	814-359-5129

I am enclosing a copy of our "SIR Request Form", which is to be used for all future species impact review requests. Please make copies of the attached form and use with all future project reviews. Thank you in advance for your cooperation and attention to this important matter of species conservation and habitat protection.

SIGNATURE: Christopher A. Urban DATE: June 7, 2007
Christopher A. Urban
Chief, Natural Diversity Section

Our Mission: www.fish.state.pa.us

To provide fishing and boating opportunities through the protection and management of aquatic resources.

PFBC-DES-NDS-1 (5/2/03)

COMMONWEALTH OF PENNSYLVANIA
FISH AND BOAT COMMISSION
NATURAL DIVERSITY SECTION
SPECIES IMPACT REVIEW (SIR) REQUEST FORM

A. This form provides the site information necessary to perform a computer database search for species of special concern listed under the Endangered Species Act of 1973, the Wild Resource Conservation Act, the Pennsylvania Fish and Boat Code or the Wildlife Code.

B. Use only ***one form*** for each proposed project or location. Complete the information below and **mail** form to:

Natural Diversity Section
Division of Environmental Services
PA Fish and Boat Commission
450 Robinson Lane
Bellefonte, PA 16823
Fax: (814) 359-5175

C. This form, a cover letter including a project narrative, and accompanying maps should be sent to the above address for environmental reviews that ***only*** concern ***reptiles, amphibians, fishes and aquatic invertebrates.*** Reviews for other natural resources must be submitted to other appropriate agencies.

D. The absence of recorded information from our databases and files does not necessarily imply actual conditions on site. Future field investigations could alter this determination. The information contained in our files is routinely updated. A review is valid for one year.

E. ***Please send us only one (1) copy of your request*** – either by fax or by mail – not both. Mail is preferred to improve legibility of maps. Facsimile submission will not improve our response turn-around time.

F. ***Allow 30 days for completion of the review from the date of PFBC receipt.*** Large projects and workload may extend this review timeframe.

G. ***In any future correspondence with us following your receipt of the SIR response, please refer to the assigned SIR number at the top left of our cover letter.***

H. **FORMS THAT ARE NOT COMPLETED IN FULL WILL NOT BE REVIEWED.**

PLEASE PRINT OR TYPE: If available, provide the potential conflict **PNDI Search Number:**______________
PFBC response should be sent to:
Company/Agency:______________________________ Form Preparer:______________________
Address:____
_______________________________________ Phone (8:00 AM to 4:00 PM):__________________
Project Description:____
____

Indicate if the project is: Transportation ☐ or Non-transportation ☐ (check one)
Will the proposed project encroach directly or indirectly (e.g., runoff) upon wetlands or waterways? Circle one for each:
Wetlands: Yes No Unknown Waterways: Yes No Unknown
County:_________________________ Township/Municipality:_________________________
Name of the United States Geological Survey (U.S.G.S.) 7.5 Minute Quadrangle Map where project is located:
_______________________________________ Project size (in acres):__________________
Attach an 8.5" by 11" photocopy (**DO NOT REDUCE**) of the section of the U.S.G.S. Quadrangle Map which identifies the project location. On this map, indicate the location of the project center (if linear, depict both ends) and outline the approximate boundaries of the project area.
Specify latitude/longitude of the project center. **Latitude:** ______° /______'/______" N
Indicate latitude/longitude in degrees-minutes-seconds format only. **Longitude:** ______° /______'/______" W

Three steps are needed to convert from decimal degrees to degrees-minutes-seconds: (1) Degrees will be the whole number. (2) To get minutes, multiply the decimal degree portion by 60. (3) Multiply the decimal minute portion by 60 to get seconds.
Example: (Latitude) 40.93748 = **40°**; 0.93748 x 60 = 56.2488'= **56'**; 0.2488 x 60 = 14.928 = **15"** = **40°56'15" N**
(Longitude) 75.94740 = **75°**; 0.94740 x 60 = 56.844' = **56'**; 0.844 x 60 = 50.64 = **51"** = **75°56'51" W**

FOR PFBC USE ONLY

SIR#	Quad Name	Data Source	Search Result-Potential Species Conflict	Action

AmerGen
An Exelon Company

Michael P. Gallagher, PE
Vice President
License Renewal Projects

Telephone 610.765.5958
www.exeloncorp.com
michaelp.gallagher@exeloncorp.com

AmerGen
200 Exelon Way
KSA/2-E
Kennett Square, PA 19348

May 22, 2007

Mr. James Leigey
Wildlife Impact Review Coordinator
Pennsylvania Game Commission
2001 Elmerton Avenue
Harrisburg, PA 17110-9797

SUBJECT: Three Mile Island Nuclear Station Unit 1 License Renewal. Request for information on state-listed threatened and endangered species and important habitats (birds and mammals).

Dear Mr. Leigey:

AmerGen is preparing an application for the U. S. Nuclear Regulatory Commission (NRC) to renew the operating license for Three Mile Island Nuclear Station Unit 1 (TMI-1). The current operating license for TMI-1 will expire in 2014. The renewal term would be for an additional 20 years beyond the original license expiration date. As part of the license renewal process, the NRC requires license applicants to "assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10 CFR 51.53). The NRC will also request an informal consultation with your office at a later date under Section 7 of the Endangered Species Act. By contacting you early in the application process, we hope to identify any issues that we need to address or any information that we should provide to your office to expedite the NRC consultation.

TMI-1 is located on Three Mile Island, in the Susquehanna River, in the Londonderry Township of Dauphin County, Pennsylvania. AmerGen began operations of TMI-1 after its purchase of the facility in 1999. The transmission lines associated with the facility are owned and operated by First Energy Corporation. Four transmission lines connect the station to the regional grid, and are thus relevant to license renewal. The Final Environmental Statement for operation prepared in 1972 by the U.S. Atomic Energy Commission identified three 230-kilovolt (kV) transmission lines that were built to connect Unit 1 to the electric grid. Two of these 230-kV lines span northeast approximately 1.4 miles in the same corridor connecting the plant with the substation at Middletown Junction. The third 230-kV line extends for 4.1 miles to the western side of the Susquehanna River connecting with the Jackson Substation near Cly. Subsequent to the publication of the Final Environmental Statement, a fourth 230-kV line was also constructed that extends 0.7 miles southeast to the TMI-1 500-kV substation. All of the transmission lines are within 150-foot wide corridors and are primarily in agricultural or pasture lands that continue to be cultivated. Included is a map of the transmission line system layered over the USGS topographic maps surrounding

May 22, 2007
Page 2 of 2

the TMI-1 facility (see Figure 1). Pennsylvania counties crossed by the transmission lines include Lancaster, Dauphin, and York. With the exception of the peregrine falcon (*Falco peregrinus*), osprey (*Pandion haliaetus*), bald eagle (*Haliaeetus leucocephalus*), AmerGen is not aware of any other state-listed species at TMI-1 or along the TMI-1-associated transmission lines. Peregrine falcons and osprey nests are known to occur on the TMI-1 property, and AmerGen cooperates with the Pennsylvania Department of Environmental Protection, Pennsylvania Game Commission, and other agencies to document and monitor these nests. Bald eagles have become relatively common along the Susquehanna River and are occasionally observed flying, foraging, or perching in the vicinity of TMI-1, but no eagle nest are known at TMI-1 or the associated transmission line corridors. A review of the Pennsylvania Natural Heritage Program web site for state-listed endangered or threatened species indicates that two mammals and ten birds have been recorded in the counties crossed by the transmission lines. In addition to the birds previously mentioned, these species include the least shrew (*Cryptotis parva*), Allegheny woodrat (*Neotoma magister*), upland sandpiper (*Bartramia longicauda*), American bittern (*Botaurus lentiginosus*), great egret (*Casmerodius alba*), sedge wren (*Cistothorus platensis*), yellow-crowned night heron (*Nyctanassa violacea*), black-crowned night heron (*Nycticorax nycticorax*), and king rail (*Rallus elegans*).

AmerGen is committed to the conservation of significant natural habitats and protected species, and expects that operation of TMI-1, including maintenance of the identified transmission lines, through the license renewal period (an additional 20 years) would not adversely affect any listed species. AmerGen has no plans to alter current operations over the license renewal period. Any maintenance activities necessary to support license renewal would be limited to previously disturbed areas.

In addition, AmerGen plans to replace the existing steam generators with newer models in the fall of 2009. These replacement activities would occur within the existing Unit 1 containment structure. A 6,000 square foot dedicated storage facility would be built within the existing industrial footprint of the site to house the old steam generators. No additional land disturbance is anticipated in support of license renewal.

Please call Fred Polaski (610) 765-5935 if you have any questions or require any additional information. After your review, we would appreciate receiving your input by August 17, 2007, detailing any concerns you may have about any listed species or critical habitat in the area, or confirming AmerGen's conclusion that operation of TMI-1 over the license renewal term would have no effect on any threatened or endangered species. This will enable us to meet our application preparation schedule. AmerGen will include a copy of this letter and your response in the Environmental Report that will be submitted to the NRC as part of the TMI-1 license renewal application.

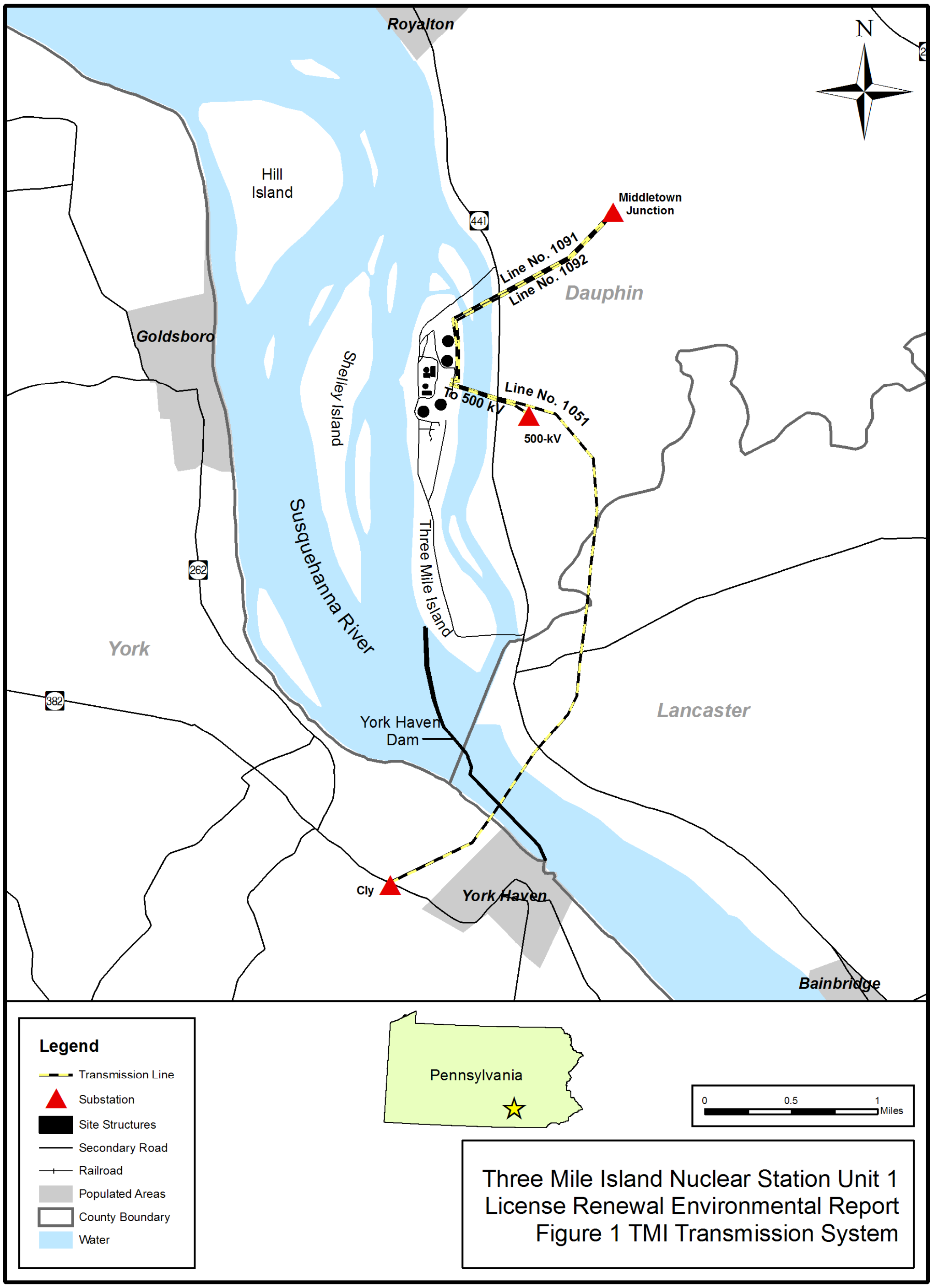
Sincerely,

Michael P. Gallagher

Michael P. Gallagher

Enclosures: Figure 1, TMI-1 Transmission System Map

Figure 1 - TMI-1, Transmission System Map
Page 1 of 1



COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA GAME COMMISSION
2001 ELMERTON AVENUE, HARRISBURG, PA 17110-9797

June 29, 2007

Mr. Michael P. Gallagher
AmerGen
200 Exelon Way
Kennett Square, PA 19348

In re: PNDI Database Review
Three Mile Nuclear Station Unit 1 License Renewal
Dauphin, Lancaster and York Counties, PA

Dear Mr. Gallagher:

This is in response to your letter dated May 22, 2007 regarding the potential impact of your proposed project on special concern species of birds or mammals recognized by the Pennsylvania Game Commission.

Our office review has determined that your proposed Three Mile Nuclear Station Unit 1 License Renewal should not cause any adverse impacts to any special concern species of birds or mammals. This determination may be reconsidered if project plans change or extend beyond the present study area, or if additional information becomes available on state-listed species.

If you have any questions, please contact me at (717) 783-5957. Please be advised that this determination is only valid for one year from the date of this letter.

Very truly yours,

James R. Leigey

James R. Leigey
Wildlife Impact Review Coordinator
Division of Environmental
Planning and Habitat Protection
Bureau of Wildlife Habitat Management

Cc: File

ADMINISTRATIVE BUREAUS:
PERSONNEL: 717-787-7836 ADMINISTRATION: 717-787-5670 AUTOMOTIVE AND PROCUREMENT DIVISION: 717-787-6594
LICENSE DIVISION: 717-787-2084 WILDLIFE MANAGEMENT: 717-787-5529 INFORMATION & EDUCATION: 717-787-6286 LAW ENFORCEMENT: 717-787-5740
LAND MANAGEMENT: 717-787-6818 REAL ESTATE DIVISION: 717-787-6568 AUTOMATED TECHNOLOGY SYSTEMS: 717-787-4076 FAX: 717-772-2411
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AmerGen
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Kennett Square, PA 19348

May 22, 2007

Mr. David Densmore
U.S. Fish and Wildlife Service
Pennsylvania Field Office
315 South Allen Street
Suite 322
State College, PA 16801

SUBJECT: Three Mile Island Nuclear Station Unit 1 License Renewal. Request for information on federally threatened and endangered species.

Dear Mr. Densmore:

AmerGen is preparing an application for the U.S. Nuclear Regulatory Commission (NRC) to renew the operating license for the Three Mile Island Nuclear Station Unit 1 (TMI-1). The current operating license for TMI-1 will expire in 2014. The renewal term would be for an additional 20 years beyond the original license expiration date. As part of the license renewal process, the NRC requires license applicants to "assess the impact of the proposed action on threatened or endangered species in accordance the Endangered Species Act" (10 CFR 51.53). The NRC will also request an informal consultation with your office at a later date under Section 7 of the Endangered Species Act. By contacting you early in the application process, we hope to identify any issues that we need to address or any information that we should provide to your office to expedite the NRC consultation.

TMI-1 is located on Three Mile Island, in the Susquehanna River, in the Londonderry Township of Dauphin County, Pennsylvania. AmerGen began operations of TMI-1 after its purchase of the facility in 1999. The transmission lines associated with the facility are owned and operated by First Energy Corporation. Four transmission lines connect the station to the regional grid, and are thus relevant to license renewal. The *Final Environmental Statement* for operation prepared in 1972 by the U.S. Atomic Energy Commission, identified three 230-kilovolt (kV) transmission lines that were built to connect Unit 1 to the electric grid. Two of these 230-kV lines span northeast approximately 1.4 miles in the same corridor connecting the plant with the substation at Middletown Junction. The third 230-kV line extends for 4.1 miles to the western side of the Susquehanna River connecting with the Jackson Substation near Cly. Subsequent to the publication of the *Final Environmental Statement*, a fourth 230-kV line was also constructed that extends 0.7 miles southeast to the TMI-1 500-kV substation. All of the transmission lines are within 150-foot wide corridors and are primarily in agricultural or pasture lands that continue to be cultivated. Included is a map of the transmission line system layered over the USGS topographic maps surrounding the TMI-1 facility (see Figure 1).

Pennsylvania counties crossed by the transmission lines include Lancaster, Dauphin, and York. Based on our direct observations, a review of TMI-1 records, and a review of the U.S. Fish and Wildlife Service web site for federally listed endangered or threatened species, AmerGen believes that the bald eagle (*Haliaeetus leucocephalus*) is the only federally listed species known to occur in the vicinity of the TMI-1 site. Bald eagles are occasionally seen flying, foraging, or perching along the Susquehanna River. No eagle nests are known to occur on Three Mile Island, but a nest has been recorded approximately 20 miles south of TMI-1 near the Holtwood Dam. The bog turtle (*Clemmys muhlenbergii*), dwarf wedgemussel (*Alasmidonta heterodon*), and Northeastern bulrush (*Scirpus ancistrochaetus*) have been recorded in the three counties associated with the TMI-1 transmission lines, but are not known to occur in the relatively short length of 5.5 miles of transmission line corridors.

AmerGen is committed to the conservation of significant natural habitats and protected species, and expects that operation of TMI-1, including maintenance of the identified transmission lines, through the license renewal period (an additional 20 years) would not adversely affect any listed species. AmerGen has no plans to alter current operations over the license renewal period. Any maintenance activities necessary to support license renewal would be limited to previously disturbed areas.

In addition, AmerGen plans to replace the existing steam generators with newer models in the fall of 2009. These replacement activities would occur within the existing Unit 1 containment structure. A 6,000 square foot dedicated storage facility would be built within the existing industrial footprint of the site to house the old steam generators. No additional land disturbance is anticipated in support of license renewal.

Please call Fred Polaski (610) 765-5935 if you have any questions or require any additional information. After your review, we would appreciate receiving your input by August 17, 2007, detailing any concerns you may have about any listed species or critical habitat in the area, or confirmation of AmerGen's conclusion that operation of TMI-1 over the license renewal term would have no effect on any threatened or endangered species. This will enable us to meet our application preparation schedule. AmerGen will include a copy of this letter and your response in the Environmental Report that will be submitted to the NRC as part of the Three Mile Island Unit 1 license renewal application.

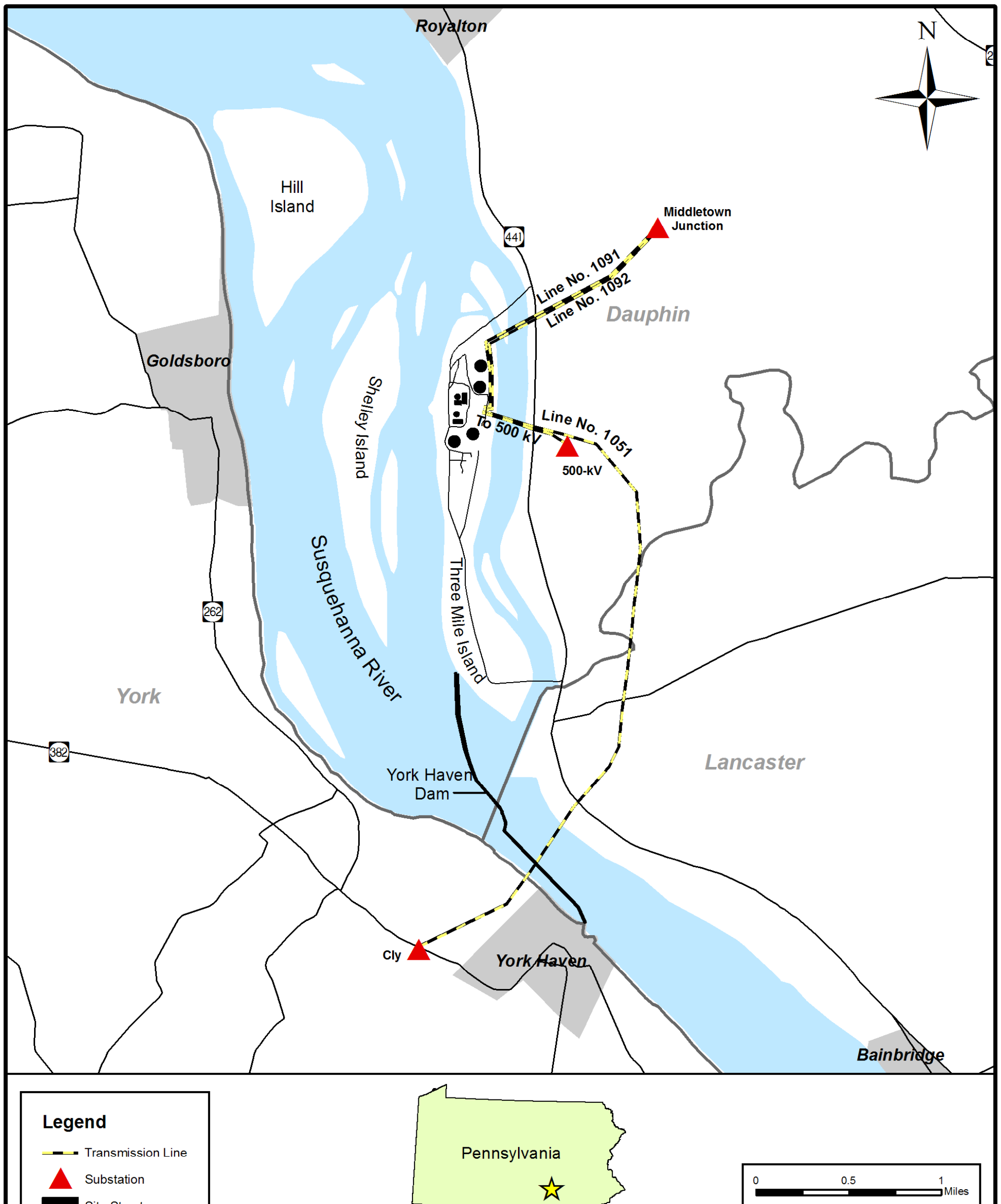
Sincerely,

Michael P. Gallagher

Michael P. Gallagher

Enclosures: Figure 1, TMI-1 Transmission System Map

Figure 1 - TMI-1, Transmission System Map
Page 1 of 1



Three Mile Island Nuclear Station Unit 1
License Renewal Environmental Report
Figure 1 TMI Transmission System

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Pennsylvania Field Office
315 South Allen Street, Suite 322
State College, Pennsylvania 16801-4850

June 7, 2007

MPA
6.11.07

Michael Gallagher
AmerGen
200 Exelon Way
KSA/2-E
Kennett Square, PA 19348

RE: USFWS Project #2007-1764

Dear Mr. Gallagher:

This responds to your letter of May 22, 2007, requesting information about federally listed and proposed endangered and threatened species within the area affected by the Three Mile Island Nuclear Station Unit 1 License Renewal, located in Lancaster, Dauphin and York Counties, Pennsylvania. The following comments are provided pursuant to the Endangered Species Act of 1973 (87 Stat. 884, as amended; 16 U.S.C. 1531 *et seq.*) to ensure the protection of endangered and threatened species.

A nest of the federally listed, threshold bald eagle (*Haliaeetus leucocephalus*) is located on the west side of the Susquehanna River to the northwest of the proposed project. Based on the nature and scale of project activities, and the distance of these activities from the nest, we do not anticipate that bald eagles will be adversely affected.

The Fish and Wildlife Service proposed to remove the bald eagle from the federal *List of Endangered and Threatened Wildlife* on July 6, 1999 (*Federal Register*, Vol. 64, No. 128), but final action on that proposal has not been taken. Therefore, the bald eagle continues to be listed under the Endangered Species Act. Any changes in the regulatory status of the bald eagle can be monitored by accessing our web site at http://www.fws.gov/migratorybirds/baldeagle.htm.

If the bald eagle is delisted, it will no longer receive protection under the Endangered Species Act, but it will continue to be protected by the Bald and Golden Eagle Protection Act (Eagle Act) and the Migratory Bird Treaty Act (MBTA). Both acts protect bald eagles by prohibiting killing, selling or otherwise harming eagles, their nests or eggs. The Eagle Act also protects eagles from disturbance.

On June 4, 2007, the Service released several important documents related to the protection of bald eagles under the Eagle Act, including 1) a final rule establishing a regulatory definition of "disturb"; 2) a final environmental assessment of the "disturb" regulation; 3) National Bald Eagle Management Guidelines; and 4) a proposed rule to establish a permit for the take of bald and golden eagles. The proposed rule would establish regulations for issuing permits to take bald and golden eagles where the take is associated with, and not the purpose of, otherwise lawful activities. A second permit type would provide for permits to take bald and golden eagle nests for safety emergencies (of humans or eagles). All of these documents can be found at the web site referenced above.

Based on our review of the proposed project, it is our determination under the Endangered Species Act that this project is not likely to adversely affect bald eagles. It is also our determination under the Eagle Act that this project will not disturb bald eagles. Because no take or disturbance is anticipated, none is authorized. If project plans change, please contact the Service to determine whether or not the project modifications will result in effects to bald eagles that may necessitate an Eagle Act permit or Endangered Species Act authorization.

To avoid potential delays in reviewing your project, please use the above-referenced USFWS project tracking number in any future correspondence regarding this project.

Please contact Pam Shellenberger of my staff at 814-234-4090 if you have any questions or require further assistance.

Sincerely,

David Densmore
Supervisor

AmerGen
An Exelon Company

Michael P. Gallagher, PE
Vice President
License Renewal Projects

Telephone 610.765.5958
www.exeloncorp.com
michaelp.gallagher@exeloncorp.com

AmerGen
200 Exelon Way
KSA/2-E
Kennett Square, PA 19348

May 22, 2007

Dept. of Environmental Protection
ATTN: Rachel Diamond, Regional Director
Southcentral Regional Office
909 Elmerton Avenue
Harrisburg, PA 17110

SUBJECT: Three Mile Island Nuclear Station Unit 1 License Renewal. Request for Information on Thermophilic Microorganisms.

Dear Mr. Aunkst:

AmerGen, is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating license for Three Mile Island Nuclear Station Unit 1 (TMI-1). The current operating license for TMI-1 will expire in 2014. Renewing the licenses would provide for an additional 20 years of operation beyond the original license expiration date. The NRC requires license applicants to provide "...an assessment of the impact of the proposed action {license renewal} on public health from thermophilic organisms in the affected water" (10 CFR 51.53). Organisms of concern include the enteric pathogens Salmonella and Shigella, the Pseudomonas aeruginosa bacterium, thermophilic Actinomycetes ("fungi"), the many species of Legionella bacteria, and pathogenic strains of the free-living Naegleria amoeba.

As part of the license renewal process, AmerGen is consulting with your office to determine whether there is any concern about the potential occurrence of these organisms in the Susquehanna River at the TMI-1 location. By contacting you early in the application process, we hope to identify any issues that we need to address or any information that we should provide to your office to expedite the NRC consultation.

AmerGen began operations of TMI-1 after its purchase of the facility in 1999. The facility is located on Three Mile Island, in the Susquehanna River in the Londonderry Township in Dauphin County, adjacent to Lancaster and York Counties, Pennsylvania (see Figure 1). TMI-1 uses two natural draft cooling towers to dissipate waste heat from the station's circulating water system. Thermal modeling conducted by the NRC for the operation of TMI-1 indicated that the station's discharge would have a modest impact on downstream river temperatures (0 to 2.0°F, during summer months). The station's National Pollutant Discharge Elimination System (NPDES) permit requires continuous temperature monitoring of the circulating cooling water systems effluent before discharge into the Susquehanna River. Recent temperature data from the stations NPDES Discharge Monitoring Reports for 2004, 2005, and 2006 indicate that the 24-hr average maximum temperature was 100.4°F.

May 22, 2007
Page 2 of 2

Water temperatures of 100°F are well below the optimal temperature range (122°F-140°F) for growth and reproduction of thermophilic microorganisms.

Fecal coliform bacteria are regarded as indicators of other pathogenic microorganisms, and are the organisms normally monitored by state health agencies. The NPDES permit for TMI-1 requires monitoring of fecal coliforms in the station's sewage treatment plant effluent. Samples are collected once per quarter for fecal coliform analysis and other parameters. The TMI-1 NPDES permit calls for "effective disinfection" to control disease-producing organisms during the swimming season (May 1 through September 30) and imposes a limit of 200 fecal coliform colonies (geometric average value) per 100 ml sample during this period. The NPDES permit also stipulates that no more than 10 percent of samples tested may contain 1,000 colonies.

Given the thermal characteristics of the Susquehanna River at the TMI-1 thermal discharge and disinfection of the station's sewage treatment plant effluent, AmerGen does not expect station operations to stimulate growth or reproduction of thermophilic microorganisms. Under certain circumstances, these organisms might be present in limited numbers in the station's discharge, but would not be expected in concentrations high enough to pose a threat to recreational users of the Susquehanna River.

We would appreciate your relating any concerns you may have about these organisms and potential public health effects over the license renewal term by August 17, 2007, or your confirmation of AmerGen's conclusion that operation of TMI-1 over the license renewal term would not stimulate growth of thermophilic pathogens. This will enable us to meet our application preparation schedule. AmerGen will include a copy of this letter and your response in the Environmental Report that will be submitted to the NRC as part of the TMI-1 license renewal application. Please call Fred Polaski (610) 765-5935 if you have any questions or require any additional information.

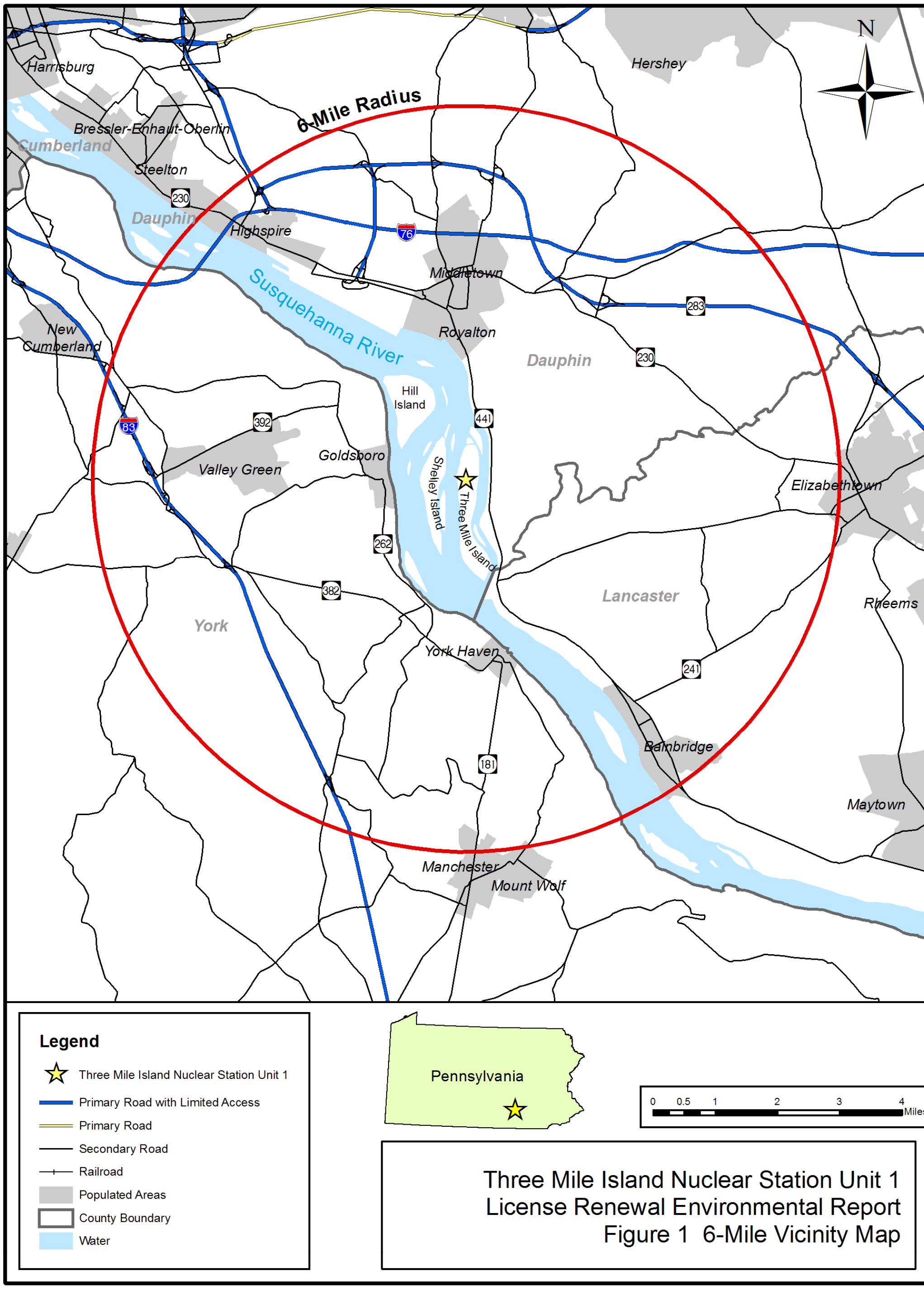
Sincerely,

Michael P. Gallagher

Michael P. Gallagher

Enclosure: Figure 1, 6-Mile Vicinity Map

Figure 1, TMI-1 6 Mile Vicinity Map
Page 1 of 1



Three Mile Island Nuclear Station Unit 1
License Renewal Environmental Report
Figure 1 6-Mile Vicinity Map

Pennsylvania Department of Environmental Protection

909 Elmerton Avenue
Harrisburg, PA 17110-8200
June 1, 2007

Southcentral Regional Office

717-705-4707
FAX - 717-705-4760

MPG 6.7.07

Michael P. Gallagher, P.E.
AmerGen
200 Exelon Way, KSA/2-E
Kennett Square, PA 19348

Re: Thermophilic Organisms
Three Mile Island Nuclear Station Unit 1
Londonderry Township, Dauphin County

Dear Mr. Gallagher:

We appreciate that AmerGen has contacted the Department with the information request concerning thermophilic organisms. We agree with AmerGen's conclusion that the discharge of cooling water from the operation of Three Mile Island Nuclear Station 1 over the license renewal term would not stimulate growth of thermophilic pathogens.

Please call me at 717-705-4795 if you have any questions or require additional information.

Sincerely,

Lee A. McDonnell, P.E.
Program Manager
Water Management Program

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Appendix D

State Historic Preservation Officer Correspondence

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Douglas C. McLearen, Pennsylvania Historical and Museum Commission to Michael P. Gallagher (AmerGen)	D-8

AmerGen
An Exelon Company

Michael P. Gallagher, PE
Vice President
License Renewal Projects

Telephone 610.765.5958
www.exeloncorp.com
michaelp.gallagher@exeloncorp.com

AmerGen
200 Exelon Way
KSA/2-E
Kennett Square, PA 19348

May 22, 2007

Jean Cutler, Deputy State Historic Preservation Officer
Pennsylvania Historical and Museum Commission
Bureau for Historic Preservation
Commonwealth Keystone Building, Second Floor
400 North Street
Harrisburg, PA 17120-0093

SUBJECT: Three Mile Island Nuclear Station Unit 1 License Renewal, Request for Information on historic and archaeological resources.

Dear Ms. Cutler:

AmerGen Energy Company, LLC (AmerGen) is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating license for Three Mile Island Nuclear Station, Unit 1 (TMI-1). The current operating license expires in 2014. The renewal term would be for an additional 20 years beyond the original license expiration date. As part of the license renewal process, NRC requires license applicants to "assess whether any historic or archaeological properties will be affected by the proposed project." NRC may also request an informal consultation with your office at a later date under Section 106 of the National Historic Preservation Act of 1966, as amended (16 USC 470), and Federal Advisory Council on Historic Preservation regulations (36 CFR 800). By contacting you early in the application process, we hope to identify any issues that need to be addressed or any information your office may need to expedite the NRC consultation.

AmerGen does not expect TMI-1 operations through the license renewal term (an additional 20 years) to adversely affect cultural resources in the area. Renewal of the TMI-1 operating license does not involve any changes or additions to the plant or transmission line structures. In addition to normal operations, AmerGen plans to replace the existing steam generators with newer models in the fall of 2009. These replacement activities would occur within the existing Unit 1 containment structure. A 6,000 square foot dedicated storage facility would be built within the existing industrial footprint of the site to house the old steam generators. This storage facility will be separately permitted, and will be located at a location that has previously been disturbed. For this project and any other potential earthworks projects, AmerGen's corporate procedures will ensure the protection of cultural resources.

Three Mile Island Nuclear Station Unit 1 is located in Londonderry Township in Dauphin County, Pennsylvania, on the northern end of Three Mile Island near the eastern shore of the Susquehanna River. Four transmission lines connect the station to the regional grid, and are thus relevant to license renewal (see Figure 1, TMI-1 Transmission System).

They include:

- Line No. 1091 – TMI-1 Plant to Middletown Junction – This 230-kV line operated by First Energy Corporation extends north for 1.4 miles in a 150-foot wide corridor to the Middletown Junction Substation near Middletown.
- Line No. 1092 – TMI-1 Plant to Middletown Junction – This 230-kV line operated by First Energy Corporation extends north for 1.4 miles in a 150-foot wide corridor to the Middletown Junction Substation near Middletown.
- Line No. 1051 – TMI-1 Plant to Jackson Substation – This 230-kV line operated by First Energy Corporation extends southwest for 4.1 miles in a 150-foot wide corridor to the Jackson Substation near Cly, west of the Susquehanna River.
- Line from TMI-1 Plant to the 500-kV Substation – This 230-kV line shares the first four towers with the TMI-1 Plant to Jackson Substation line. The line extends southwest for 0.7 miles and connects to the 500-kV Substation.

In total, the transmission lines of interest are contained in approximately 5.5 miles of corridor that occupy approximately 130 acres. The TMI-1 Plant to Middletown Junction lines have adjacent corridors. The corridors pass through land that is primarily agricultural. The areas are mostly remote, with low population densities. Corridors that pass through pastures generally continue to be used as pastures. Each of the lines crosses State Highway 441 after leaving the switchyard. The TMI-1 Plant to Jackson Substation line also crosses several smaller roads.

Using the National Register Information System (NRIS) on-line database, we have compiled a list of sites on the National Register of Historic Places within a six-mile radius of the TMI-1 property. Table 1 (see attached) details those sites. We will provide this information to the NRC to aid in its evaluation of the license application.

Additionally, we will notify the NRC of cultural resources investigations of the TMI-1 site that have been performed. In 1967, TMI-1's applicants funded an archaeological survey and subsequent excavation of artifacts from the island prior to construction. The survey and excavation was conducted by the Pennsylvania Historical and Museum Commission (PHMC 1977). More than 1,000 artifacts were found and, from these artifacts, it was deduced that the site had period components ranging from 4,000 B.C. to 1,000+ A.D.

In April, 1987, a paper was presented at the Mid Atlantic Archaeological Conference Annual Meeting in Lancaster, Pennsylvania by two archaeologists detailing work they'd performed in relation to Three Mile Island (Mangold and Grace 1987). The archaeologists wanted to more clearly define the cultural occupations of the island by 1) inspecting extant private collections of those who've collected artifacts from Three Mile Island, 2) reviewing previous archaeological investigations, and 3) performing limited testing on the island. Their investigation led to the conclusion that cultures from the prehistoric Early Archaic through the historic Susquehannock Indians used the island and that much of the cultural data, stratigraphy, and features indicating human activity remain to be investigated.

In 1988, the Curator of Archaeology from the State Museum of Pennsylvania performed an investigation of a burial site discovered on the southern tip of the island by a TMI-1

May 21, 2007
Page 3 of 4

employee. The Curator concluded that the human burial was not the product of a recent homicide, but the remains of a 19th century island resident. The remains were collected and later reburied in a location near their original burial site. Associated cultural materials (i.e., clothing buttons, coffin nails, etc.) were collected and donated to the State Museum of Pennsylvania for perpetual curation (Burke 2006).

In 1999, the PHMC held a public history symposium and erected a "historical marker" on State Highway 441, south of the TMI-1 Visitor Center sign, commemorating the 20th anniversary of the TMI-1 Unit 2 accident. The symposium was a cooperative effort of the Pennsylvania Department of Environmental Protection, the Pennsylvania Historical Museum Commission, Pennsylvania State University - Harrisburg, the NRC, GPU Nuclear Incorporated, Three Mile Island Alert, Middletown Borough, and Londonderry Township (PHMC 1999).

Please call Fred Polaski (610) 765-5935, if you have any questions or require any additional information. After your review, we would appreciate receiving your input by August 17, 2007, detailing any concerns you may have about cultural resources in the area or confirming AmerGen's conclusion that operation of TMI-1 over the license renewal term would have no effect on cultural resources. This will enable us to meet our application preparation schedule. AmerGen will include a copy of this letter and your response in the Environmental Report that will be submitted to the NRC as part of the TMI-1 license renewal application.

Sincerely,

Michael P. Gallagher

May 21, 2007
Page 4 of 4

References:

PHMC (Pennsylvania Historical and Museum Commission). 1977. "Early and Middle Woodland Campsites on Three Mile Island, Dauphin County, Pennyslvania." Pennsylvania Historical and Museum Commission, William Penn Memorial Museum. Harrisburg, Pennsylvania. January.

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Attachments: Table 1, Figure 1, TMI-1 Transmission System Map.

Attachment 1 – Table 1
Page 1 of 2

Table 1 Sites Listed in the National Register of Historic Places and Department of Interior sites that fall within a 6-mile Radius of TMI

Site Name	Location
National Register of Historic Places Sites	
Byers-Muma House	1402 Trout Run Road, East Donegal Lancaster County
Donegal Presbyterian Church Complex	Donegal Springs Road, East Donegal Lancaster County
Kreider Shoe Manufacturing Company	155 South Poplar Street, Elizabethtown Lancaster County
B'Nai Jacob Synagogue	Nissley and Water Streets, Middletown Dauphin County
Simon Cameron House and Bank	28 and 30 East Main Street, Middletown Dauphin County
Henniger Farm Covered Bridge	Northeast of Elizabethville Dauphin County
Highspire High School	221 Penn Street, Highspire Dauphin County
Charles and Joseph Raymond Houses	37 and 38 North Union Street, Middletown Dauphin County
Henry Smith Farm	950 Swatara Creek Road, Middletown Dauphin County
St. Peter's Kierch	31 West High Street, Middletown Dauphin County
Star Barn Complex	Nissley Drive at PA 283, Lower Swatara Dauphin County
Swatara Ferry House	400 Swatara Street, Middletown Dauphin County
Michael and Magdealena Bixler Farmstead	400 Mundis Race Road, East Manchester York County
Codorus Forge and Furnace Historic District	Junction of River Farm and Furnace Roads, Hellam Township, Saginaw York County
Goldsboro Historic District	Roughly bounded by North, Third, Fraser, and Railroad Streets, Borough of Goldsboro York County
Hammersly-Strominger House	Northeast of Lewisberry on PA 177, Lewisberry York County
Kise Mill Bridge	LR 66003 over Bennett Run, Woodside York County
Kise Mill Bridge Historic District	Address Restricted, York Haven York County

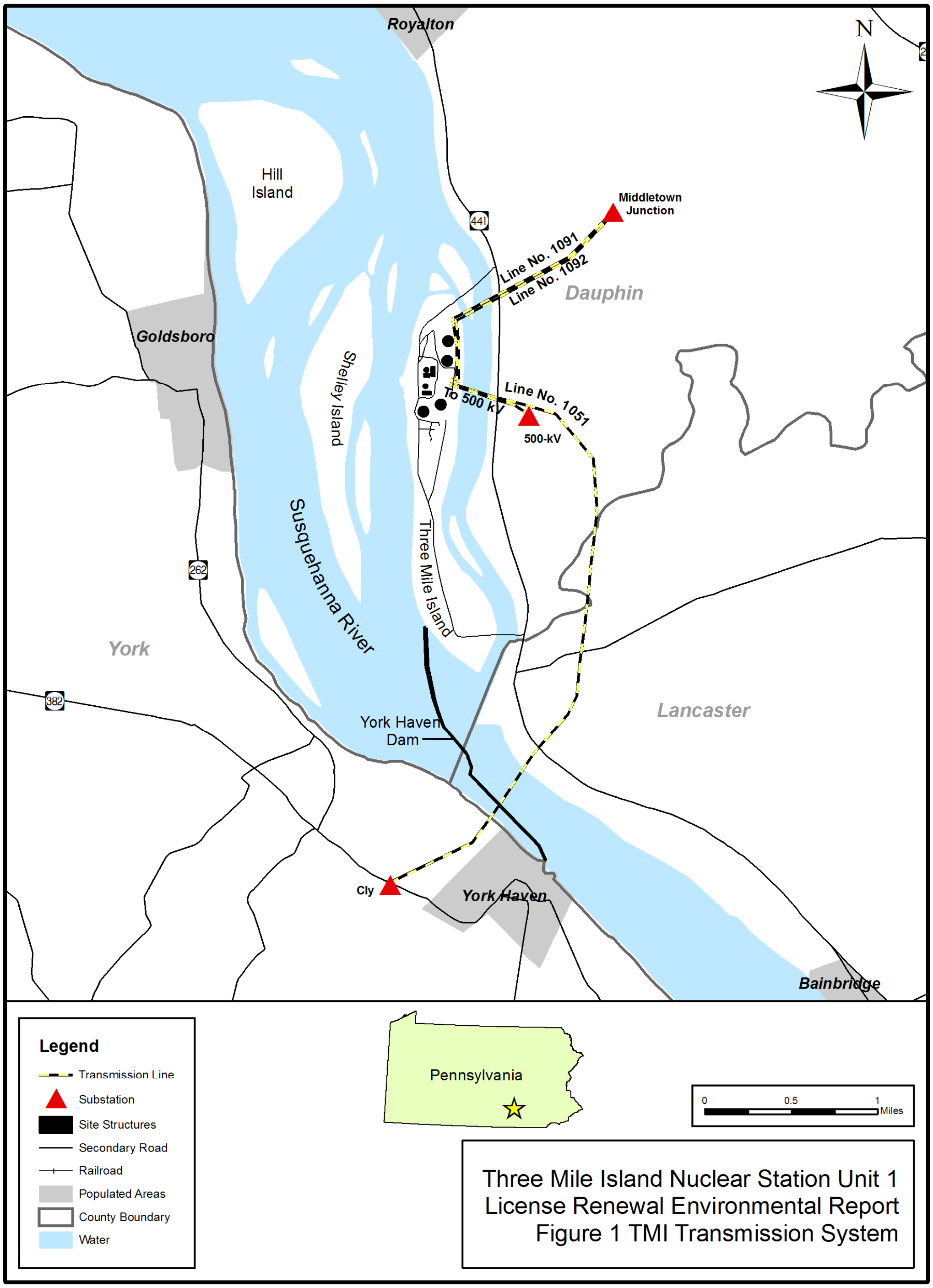
Attachment 1 – Table 1
Page 2 of 2

Table 1 Sites Listed in the National Register of Historic Places and Department of Interior sites that fall within a 6-mile Radius of TMI (continued)

Site Name	Location
Sinking Springs Farms	Roughly bounded by Church Road, Sinking Springs Lane, North George Street, Locust Lane, Susquehanna Trail, and PA 238, Manchester York County
Sites Eligible for Listing	
Haldeman Mansion	Township Road 839, Bainbridge Township Lancaster County
Goldsboro Historic District	Borough of Goldsboro, York County
Lewisberry Historic District	Roughly bounded by Lewis Street, City Unavailable York County
Newberrytown Historic District	Village of Newberrytown York County

Source: USDOI 2006.

Figure 1 - TMI-1, Transmission System Map
Page 1 of 1



Commonwealth of Pennsylvania
Pennsylvania Historical and Museum Commission
Bureau for Historic Preservation
Commonwealth Keystone Building, 2nd Floor
400 North Street
Harrisburg, PA 17120-0093
www.phmc.state.pa.us

June 4, 2007 MPG 6.7.07

Michael P. Gallagher
AmerGen
200 Exelon Way
KSA/2-E
Kennett Square, PA 19348

TO EXPEDITE REVIEW USE
BHP REFERENCE NUMBER

Re: File No. ER 07-1737-043-A
NRC: Three Mile Island Nuclear
Station Unit 1 License Renewal
Londonderry Twp., Dauphin Co.

Dear Mr. Gallagher:

The Bureau for Historic Preservation (the State Historic Preservation Office) has reviewed the above named project in accordance with Section 106 of the National Historic Preservation Act of 1966, as amended in 1980 and 1992, and the regulations (36 CFR Part 800) of the Advisory Council on Historic Preservation. These requirements include consideration of the project's potential effect upon both historic and archaeological resources.

There may be historic buildings, structures, and/or archaeological resources located in the project area. In our opinion the activities described in your proposal should have no effect on these resources. Should you become aware, from any source, that unidentified historic buildings, structures, and or archaeological resources are located at the project site, or that the project activities will have an effect on these properties, the Bureau for Historic Preservation should immediately be contacted.

If you need further information regarding archaeological survey please contact Doug McLearen at (717) 772-0924. If you need further information concerning historic structures please consult Susan Zacher at (717) 783-9920.

Sincerely,

Douglas C. McLearen, Chief
Division of Archaeology &
Protection

DCM/tmw

Appendix E

SAMA ANALYSIS

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Acronyms Used in Attachment E

AC	alternating current
ADV	atmospheric dump valve
AFW	auxiliary feedwater
ATWS	anticipated transient without scram
BWR	boiling water reactor
BWST	borated water storage tank
CCF	common cause failure
CDF	core damage frequency
CET	containment event tree
CFS	cavity flooding system
CR	control room
CRD	control rod drive
CS	containment spray
CST	condensate storage tank
DA	data analysis
DC	direct current
DCH	direct containment heating
DG	diesel generator
DHCCW	decay heat closed cooling water
DPD	dollar per dollar
ECCS	emergency core cooling system
EDG	emergency diesel generator
EFW	emergency feedwater
EOP	emergency operating procedures
EPRI	electric power research institute
EPZ	emergency planning zone
FIVE	fire induced vulnerability evaluation
FP	fire protection
FPS	fire protection system
F-V	Fussell-Vesely
GIS	geographic information system
gpm	gallons per minute
HEP	human error probability
HPCI	high pressure coolant injection
HPI	high pressure injection
HPME	high pressure melt ejection
HPSI	high pressure safety injection
HRA	human reliability analysis
HVAC	heating ventilation and air-conditioning system
IA	Instrument air
ICS	instrumentation and control system
IE	initiating event
IPE	individual plant examination
IPEEE	individual plant examination – external events
ISLOCA	interfacing system LOCA
JHEP	joint human error probability
LERF	large early release frequency
LLNL	Lawrence Livermore National Labs
LOCA	loss-of-coolant accident

Acronyms Used in Attachment E

LOOP	loss of off-site power
LPR	low pressure recirc
LPSI	low pressure safety injection
MAAP	modular accident analysis program
MACCS2	melcor accident consequences code system, version 2
MACR	maximum averted cost-risk
MCC	motor control center
MCR	main control room
MET	meteorological
MSIV	main steam isolation valve
msl	mean sea level
MTC	moderator-temperature co-efficient
NPSH	net positive suction head
NRC	U.S. nuclear regulatory commission
NSCCW	Nuclear Services Closed Cooling Water
NSRW	Nuclear Service River Water
OECR	off-site economic cost risk
OSP	off-site power
OTSG	once through steam generator
PDS	plant damage state
PORV	pressure operated relief valve
PRA	probabilistic risk analysis
PSA	probabilistic safety assessment
PTS	pressurized thermal shock
PWR	pressurized water reactor
RBNC	reactor building normal cooling
RCIC	reactor core isolation cooling
RCP	reactor coolant pump
RCS	reactor coolant system
RDR	real discount rate
RHR	residual heat removal
RHRSW	residual heat removal service water
RPV	reactor pressure vessel
RRW	risk reduction worth
RSP	remote shutdown panel
SAMA	severe accident mitigation alternative
SBO	station blackout
SDP	significance determination process
SGTR	steam generator tube rupture
SPRA	seismic PRA
SRV	safety relief valve
SSC	systems structures & components
SSES	Susquehanna Steam Electric Station
SSHR	secondary side heat removal
SSRW	secondary service river water
ST	structural response
SW	service water
TD EFW	turbine driven EFW
TMI	Three Mile Island

Appendix E
Severe Accident Mitigation Alternatives

The severe accident mitigation alternatives (SAMA) analysis discussed in Section 4.20 of the Environmental Report is presented below.

E.1 METHODOLOGY

The methodology selected for this analysis involves identifying SAMA candidates that have the highest potential for reducing plant risk below the currently acceptably-low levels and determining whether or not the implementation of those candidates is beneficial on a cost-risk reduction basis. The metrics chosen to represent plant risk include the core damage frequency (CDF), the dose-risk, and the off-site economic cost-risk. These values provide a measure of both the likelihood and consequences of a core damage event. The SAMA process consists of the following steps:

- TMI-1 Probabilistic Risk Assessment (PRA) Model – Use the TMI-1 Internal Events PRA model as the basis for the analysis (Section E.2). Incorporate external events contributions as described in Sections E.4.6 and E.6.

- Level 3 PRA Analysis – Use TMI-1 Level 1 (CDF) and Level 2 (Containment Response) Internal Events PRA output and site-specific meteorology, demographic, land use, and emergency response data as input in performing a Level 3 (offsite consequences) PRA using the MELCOR Accident Consequences Code System Version 2 (MACCS2) (Section E.3).

- Baseline Risk Monetization – Use U.S. Nuclear Regulatory Commission (NRC) regulatory analysis techniques to calculate the monetary value of taking no further action to reduce the consequences of potential severe accidents for TMI-1. This becomes the maximum averted cost-risk (MACR) that is possible (Section E.4).

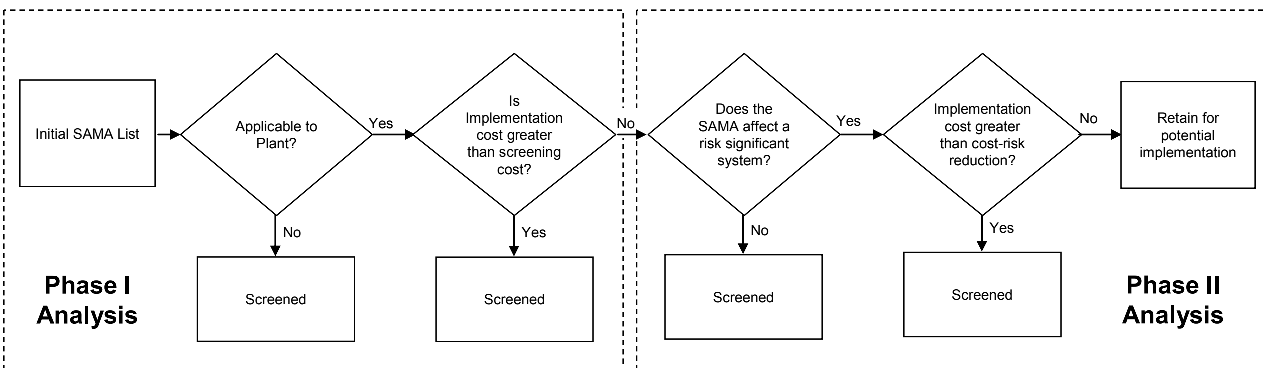
- Phase I SAMA Analysis – Identify potential SAMA candidates based on the TMI-1 PRA, Individual Plant Examination – External Events (IPEEE), and documentation from the industry and NRC. Screen out Phase I SAMA candidates that are not applicable to the TMI-1 design or are of low benefit in pressurized water reactors (PWRs) such as TMI-1, candidates that have already been implemented at TMI-1 or whose benefits have been achieved at TMI-1 using other means, and candidates whose estimated cost exceeds the possible MACR (Section E.5).

- Phase II SAMA Analysis – Calculate the risk reduction attributable to each remaining SAMA candidate and compare to a more detailed cost analysis to identify the net cost-benefit. PRA insights are also used to screen SAMA candidates in this phase (Section E.6).

- Uncertainty Analysis – Evaluate how changes in the SAMA analysis assumptions might affect the cost-benefit evaluation (Section E.7).

- Conclusions – Summarize results and identify conclusions (Section E.8).

The steps outlined above are described in more detail in the subsections of this appendix. The graphic below summarizes the high-level steps of the SAMA process.



E.2 THREE MILE ISLAND PRA MODEL

This section provides a summary of the Three Mile Island (TMI) PRA model used to support the SAMA analysis and the changes that have been made to the model since the individual plant examination (IPE). The external events models are not specifically discussed in this section.

E.2.1 LEVEL 1 TMI PRA MODELS

The TMI 2004 Revision 2 Level 1 PRA model (Exelon 2007a), the most recent model, calculated a Core Damage Frequency (CDF) of 2.37E-5/yr and a value for Large Early Release Frequency (LERF) of 3.02E-06/yr. Table E.2-1 summarizes the historical values for previous TMI models and their calculated values for CDF and LERF.

E.2.2 HISTORY OF THE TMI PRA MODELS

E.2.2.1 RISKMAN PRA MODELS

The TMI-1 Level I PRA was updated in late 1989 and 1990 to revise the internal events portion of the Level I PRA that was initially completed in 1987. The updates were undertaken to reflect changes in plant design and procedures made since 1987 and to fulfill the requirements of NRC Generic Letter 88-20, "Individual Plant Examinations". In conformance with those requirements the major objectives of the PRA update were to:

1. Further develop an appreciation of severe accident behavior.
2. Build on the understanding of the most likely severe accident sequences that could occur at TMI-1.
3. Improve the quantitative understanding of the overall probabilities of core damage.

The updates were conducted in a manner that maximized the use of in-house personnel. Plant and Support PRA analysts and engineers and operators who were familiar with the details of the design, controls, procedures, and system configurations were directly involved in the analysis as well as the technical review.

Various consultants have assisted the TMI-1 PRA staff in the update by providing expertise in the plant model revisions and in various special analyses. An additional objective of the study was to build on existing in-house PRA expertise and to develop tools for ongoing risk management activities after the completion of the PRA update.

The IPE submittal (December 1992 model) was based on the plant as it was configured in 1991. The RISKMAN models of 2000, 2001, and 2003 were based on the plant as it was configured in 1998. The 2001 model, which was known as L2RV2, was the one primarily used for configuration risk management purposes. Although the 2003 RISKMAN model (ABSA) (ABS 2003) was not officially used for configuration risk management purposes, it provided the basis for later PRA models that were converted to CAFTA. The list below shows the major plant and procedure changes made since 1987 that were significant to these RISKMAN PRA models. Most of these changes were made as a result of insights gained from the original 1987 PRA model.

1. Addition of an alternate AC source (TMI Unit 2 diesel generator) with the ability to tie into either division of 1E power.
2. Installation of improved reactor coolant pump seals that reduce the likelihood of seal failure under loss of injection and cooling conditions.
3. Modification of the power supplies to the ICS that eliminates loss of 120V AC bus ATA power as an initiating event.
4. Addition of an air compressor, air dryer and filters that improves the reliability of the instrument air system.
5. Change to procedure for loss of air that directs the operator to manually open RCP seal return valve (MU-V-20). This assures continuation of RCP seal injection during loss of air scenarios.
6. Modification of the power supplies to the "B" HPI pump and its associated lube oil pumps that assures they both are supplied from the same source of power. This reduces the chances of pump failure if power is lost.
7. Relocation of the control switches for HPI pump min-recirc valves (MU-V-36 and 37) from the back panels to the control room console. This reduces the likelihood of operator failure to re-establish min-recirc after throttling HPI and thus reduces the likelihood of pump damage and consequent loss of RCP seal injection.
8. Changes to procedures for loss of river water events that direct the operator to alternate make-up pumps to utilize the heat capacity of the DHCC system as a heat sink for pump cooling, and if necessary to cross-connect firewater to the DHCC heat exchangers. This reduces the likelihood that a loss of river water intake event would lead to loss of RCP seal injection.
9. A change to torque switch settings for DHR isolation valves (DH-V-4A & B) that improves the ability of the valves to be closed against a high differential pressure. This reduces the likelihood of an interfacing system LOCA (ISLOCA) through these valves.
10. Addition of a diverse scram system to reduce the likelihood of an ATWS.

11. Modification of the balance of plant power supply distribution to minimize the chances of trip due to loss of DC train A.

12. Replacement of the analog turbine control system with a digital control system.

For a closeout summary of the recommendations of the 1987 PRA, which includes most of these changes, see GPUN letter to NRC of February 22, 1990 (H.D. Hukill to NRC, #C311-90-2012).

Two independent reviews of the December 1992 update were conducted: one by an independent in-house group consisting of managers of key organizations, and one by an external consultant. The purpose of the independent in-house review was to ensure the accuracy of the documentation and to validate the PRA process and its results. The external consultant review was conducted to ensure that proper PRA techniques were employed and that key issues were addressed. The results of these reviews were provided in Appendix D of Reference (GPU 1992).

E.2.2.2 CAFTA PRA MODELS

As mentioned above, the ABSA 2003 RISKMAN model provided the basis for a conversion to a Level 1 CAFTA software model in 2004. The ABSA model addressed significant findings from the TMI PRA Peer Certification (“A” and “B” F&Os). The CAFTA conversion improved the details in several system models, accident sequence event trees, and updated the initiating event and component failure/unavailability rates. Changes made to the PRA were done to support procedural requirements for a periodic update to support risk informed applications and configuration risk management. The 2004 Revision 0 model was never officially implemented, with the 2004 Revision 1 model being the official model of record since June 2005 (Exelon 2005b). The 2004 Revision 1 upgrade was performed to correct errors discovered subsequent to the conversion to CAFTA (the 2004 Rev. 0 model) and enhance the model for use in configuration risk management.

Key changes made to the TMI PRA since the RISKMAN TMIL2RV2 model of 2001 are listed below. Changes made to the model for the interim 2003 update (TMIABSA) are so designated:

1. [TMIABSA] Incorporated updated values for initiating event frequencies, component failure rates, unavailability, and common cause factors.

2. [TMIABSA] Updated the Level 2 model assumptions to reflect progress in industry research and understanding from the last several years.

3. [TMIABSA] Updated entire HRA using EPRI HRA Calculator.

4. [TMIABSA] Re-evaluated success criteria and operator action timing using results from updated thermal-hydraulic (MAAP) analyses.

5. [TMIABSA] Refined the screening analysis previously used for internal flooding

6. Converted the Model from a RISKMAN linked event tree model to a CAFTA single top event fault tree model. During this conversion each event tree was modified.

7. Enhanced the following system models:

    Main Feedwater and Main Steam as they relate to OTSG isolation for SGTR and secondary line breaks.

    4KV/480V AC power was updated to include individual fault trees for 480V buses and MCCs.

    Updated common cause data to NUREG/CR-5497.

    Added logic to evaluate system availability following offsite power recovery.

8. Performed a detailed operator action dependency analysis. Developed Joint Human Error Probability (JHEP) basic events and added them to the PRA model as appropriate.

9. Performed numerous minor updates and enhancements to the model, which included changes to basic event names and probabilities, nodal logic for most event trees, and the logic for several top events and systems. These changes are all described in Attachment C of Reference (Exelon 2005b).

The 2004 Revision 2 model, upon which this SAMA analysis is based, superseded the Revision 1 model in 2007. Key changes and modifications included revision of common cause failure events and their probabilities using the data provided in (NRC 1998b). A summary listing of the changes and improvements made since the 2004 Revision 1 model is listed below:

1. New basic events were added to the PRA model for common cause failures of the batteries, inverters, battery chargers, pressurizer safety valves, and steam generator atmospheric dump valves.

2. New maintenance unavailability events were added to include maintenance on various components not previously modeled. Various old maintenance unavailability basic event names were replaced with new names to adopt a more consistent naming scheme. The time period for the maintenance unavailability data was the same as that used for the Revision 1 model (1998 to 2001).

3. Revision of fault tree logic for the makeup pumps in support of the high pressure injection and reactor coolant pump (RCP) seal injection functions.

4. Uncertainty data was added to the TMI database files, which identified error factors and the distribution type (lognormal) for type code assignments and unique basic events, such as maintenance unavailabilities, common cause events, and human event probability (HEP) actions.

5. Addition of new HEPs for controlling emergency feedwater, cooldown of the reactor coolant system (RCS), and steam generator isolation.

6. New HEP dependencies were identified and JHEP events created to account for the addition of new HEPs within the PRA model for the electrical DC and Nuclear Service River Water (NSRW) systems.

7. The loss of offsite power (LOOP) initiating event frequency was revised to be 4.48E-2 per year based on a generic prior distribution with a Bayesian update using data from 1997 to 2003.

8. Since low pressure recirculation (LPR) was considered a viable option given the success of cooling down the RCS, the event tree for Very Small LOCAs was modified to include a low pressure recirculation node.

9. New logic was added to account for makeup pump lube oil pump run failures and power supply dependencies, since failure of both lube oil pumps will fail their respective makeup pump.

10. New logic was added to the Decay Heat River Water system fault trees to account for the fact that the decay heat river pumps are running about 50% of the time (25% for each train), and thus would not need to start.

11. Improvements were made to the logic for the NSRW system that credits use of the Secondary Service River Water (SSRW) system to recover failures of NSRW, e.g., failure of the NSRW pumps. Also, adjustments were made to take credit for recovery of certain loss of NSRW initiators (%LNR); since it was found that a 73% contribution toward initiating event %LNR was recoverable by use of the NSRW-SSRW cross-tie.

12. Inverters 1E and 1F in the 120V AC vital electrical system were credited with the ability to provide a backup power supply for the normally in-service inverters.

Section E.2.4 summarizes the peer reviews performed on the TMI-1 PRA models.

E.2.2.3 TMI LEVEL 2 MODEL

The Level 2 model used for the SAMA analysis is linked to the core damage sequences from the CAFTA 2004 Revision 2 Level 1 model described above. The methodology for the Containment Event Tree (CET) solution, the CET quantification, and source term development were based on the TMI IPE Level 2 analysis of 1993, which was originally based on the Oconee PRA Level 2 analysis. Oconee and TMI-1 designs were compared to identify any significant differences in plant characteristics. Then, the Oconee CET model and its quantification were modified to reflect these differences, as well as develop a plant specific model for TMI-1. TMI-1 specific analyses using the MAAP code were performed to further enhance the Oconee model and verify its applicability to TMI-1. The TMI CAFTA Level 2 model of 2007 and CET used for this SAMA analysis are fully described in the TMI-PRA-001 (Exelon 2007b).

E.2.2.3.1 Level 1 to Level 2 Interface

In order to determine the consequences of a reactor accident, the sequences identified as leading to core damage must be analyzed in terms of various phenomena that can occur in-plant (i.e., inside the reactor vessel and containment). This involves carrying the sequences through the Containment Event Tree (CET) and determining the radionuclide releases for the various pathways through the CETs. To make this process more manageable, core damage sequences with similar characteristics are grouped into Plant Damage States (PDSs). This grouping procedure was developed through an iterative process resulting in a method that allowed core damage sequences to be grouped according to the status of plant systems at the onset of core damage (Duke 1990).

PDSs are a combination of three separate binning characteristics:

1. Core melt bin - describes the status of the primary (reactor coolant) system and related systems during core damage.
2. Containment safeguards state - describes the status of containment related systems.
3. Containment isolation state - determines whether or not containment is isolated.

The description of the binning process is discussed in terms of assigning sequences to core melt bins and use of a “bridge” tree to categorize containment safeguards/isolation states; however, these are concepts that are applied in the nodal logic of the CET rather than complete, stand alone event trees or decision trees. For example, each CET sequence includes all core damage cutsets in the “initiating event” of the sequence, but for each node, specific core melt binning logic is used to quantify the node. For the “BYPASS” CET node, one of the inputs is a gate containing Core Melt Bin 19 events (CM-019), which are ISLOCA events. Gate CM-019 was manually created based on the Plant Damage State rules and used for the “BYPASS” evaluation because it satisfied the requirements for “containment bypass” cases.

Similarly, the containment safeguards/isolation state bridge tree was used to manually develop logic gates for use in the CET nodes. An example of how the bridge tree logic is used is the evaluation of the “Fission Product Scrubbing is Effective” node. One potential means of scrubbing is the “plateout” mechanism, which is possible for releases that occur in the lower section of the auxiliary building. These include safeguard/isolation states G through R of the bridge tree. Logic representing these safeguard/isolation states was developed and included in the CET logic to allow only those sequence including isolation failures to pass through "plateout" logic for the "Fission Product Scrubbing is Effective" node.

Section E.2.2.3.1.1 provides further details related to the development of the PDS definitions for TMI-1.

E.2.2.3.1.1 DEVELOPMENT OF PLANT DAMAGE STATES

The plant damage states consider both the characteristics of the core material released to the environment and the mechanism by which the release is made from the containment. The content of the release is determined by the multiple factors, including the way in which core debris interacts with the containment and on the operation of mitigating systems, such as containment spray. The containment failure mode determines other factors such as the size and timing of the release. These issues are described in more detail in the following subsections.

E.2.2.3.1.1.1 SEQUENCE CHARACTERISTICS THAT AFFECT CONSEQUENCE ANALYSIS

Source Term Magnitude and Isotopic Content

The magnitude and isotopic content of the source term are affected by:

- The mechanisms by which radionuclides are released from the fuel,
- Retention of radionuclides in the primary system,
- The performance of active radionuclide removal systems such as the containment sprays,
- The mechanisms by which radionuclides are naturally removed from the containment atmosphere, and
- The mode of containment failure.

The mechanisms by which radionuclides are released from the fuel depend on the progression of the accident. For example, if energetic attack of the concrete basemat by the core debris occurs, this can release large amounts of tellurium, a significant contributor to early fatalities. If a continuous supply of water contacts the core debris, a coolable debris bed can be formed and the tellurium release can be prevented or terminated (FAI 1987). Thus, it is necessary to know what plant conditions cause water to be present in the reactor cavity and at what times.

Retention of fission products in the primary system can also be affected by system response. For example, core melt sequences following a large LOCA would result in significantly less primary inventory retention than would station blackout core melt sequences. Additionally, such factors as secondary side heat removal (SSHR) also affect the likelihood of revaporization of deposited radionuclides later in an accident. Revaporization of deposited radionuclides near the time of containment failure can significantly increase the release to the environment from a late containment overpressurization.

Active radionuclide removal is accomplished by the containment sprays (NRC 1982). Containment sprays affect the magnitude of the source term by removing radionuclides from the atmosphere. Sprays affect the isotopic content of the source term because they are much more efficient in removing particulates than other forms of radionuclides. Therefore, it is necessary to know if and when containment sprays are operating.

Natural removal processes also affect the magnitude of the source term. The effectiveness of gravitational settling and plateout on walls is dependent to a certain extent on the thermal-hydraulic conditions of the containment atmosphere. More importantly, it depends on the residence time of radionuclides in a given volume and thus on the type and time of containment failure.

Containment Failure

The energy and duration of the radionuclide release and the warning time for evacuation are influenced by the type and time of containment failure. A structural (large breach) failure due to overpressurization will have a high energy of release as the containment rapidly depressurizes to atmospheric pressure from its failure pressure. The duration of release will be short due to the rapidity of the depressurization. Containment leakage due to an isolation failure would be more gradual. The duration of the release would be longer, and the energy associated with that release would be lower than for the puff release from overpressurization-induced failure. If containment integrity is maintained and the only releases are associated with design leakage, the energy of release is negligible and its duration is very long. Thus, the energy and duration of release depends on the type, or mode, of containment failure.

Warning time for evacuation is the time between the loss of long-term cooling capability and the release of radioactivity to the environment. An early core melt followed by an early containment failure (prior to 5 hours) does not allow much warning time (approximately 0-2 hours), whereas a late overpressurization may be gradual and predictable, allowing a significant amount of time for evacuation. The timing of containment failure can thus have an effect on warning time.

Containment overpressurization can result from large combustible gas burns, steam spikes, direct containment heating (DCH), and a gradual buildup of steam and/or non-condensables. Since TMI-1's containment is constructed on limestone concrete, core-concrete interaction results in significant non-condensable gas (e.g., CO and CO2) production. Carbon monoxide is a combustible gas. The computer code MAAP, which was used to model containment behavior following postulated core melt events, allows for carbon monoxide to burn in the same fashion as hydrogen for combustible gas burns in containment.

Combustible gas burns are influenced by the concentrations of oxygen and steam within the containment. The timing and severity of a combustible gas burn can also depend on the rate at which hydrogen is released to the containment from the Reactor Coolant System (RCS). In general, the larger the leak path (break size), the faster the hydrogen is released and the smaller the amount that is retained in the RCS until reactor vessel failure. The leakage path also affects the rate of hydrogen production in the core by controlling the release rate of steam. The amount of steam available for the oxidation reaction affects the rate at which hydrogen is formed. The Containment Air Cooling Units (CACUs) also affect the combustible gas phenomenon within the containment. The CACUs are responsible for removing heat from the containment atmosphere and they also circulate the air within the containment, thus developing uniform concentrations of atmospheric constituents. The CACUs reduce the steam concentration, thus providing more suitable conditions for combustible gases to burn. However, the operation of the CACUs will also lower the containment base pressure and help to mitigate the effects of a combustible gas burn.

DCH is another phenomenon that can lead to containment overpressurization. This phenomenon is important for sequences in which a core melt is initiated while the RCS is at a high pressure. It has been hypothesized that the corium (molten core material) can be ejected, under high pressure, from the reactor vessel and be dispersed into the containment atmosphere as finely fragmented particles. Airborne particulate debris could then rapidly release chemical (oxidation of metallic constituents) and thermal energy directly to the containment atmosphere.

Although the CACUs are not sufficient to stop DCH from occurring, their operation would be expected to lower the containment base pressure and thus help to mitigate the effects of DCH.

The containment sprays can also help mitigate the effect of combustible gas burns and DCH by reducing the static containment pressure.

It has been stated that the warning time for evacuation is defined as the time between loss of long-term cooling capability and the release of radionuclides to the environment. The time from shutdown to the loss of long-term cooling capability impacts the warning time given that the core decay heat load, and therefore the time to core melt, is a function of time. Even though recommended evacuation times are much longer than two hours, studies of past evacuations have shown that two hours is more than sufficient time to evacuate the majority of the population participating in the evacuation plan (PRC 1981). The SAMA evaluation uses site specific analysis to evaluate the impact of evacuation of offsite consequence, as described in Section E.3.6.

E.2.2.3.1.1.2 CORE MELT BINS

The core melt bin is the first of three characteristics that define the PDS. The core melt bin definition describes the status of the RCS and associated systems at the onset of core damage. Table E.2-2 lists the 19 core melt bins used in the TMI-1 PRA and provides a brief definition of each. This section describes the derivation of the core melt bin definitions, in terms of the RCS leakage rate, loss of primary system makeup capability, and the condition of SSHR. Tables E.2.3 through E.2.13 document how each of the core damage sequences are assigned to the core melt bins.

E.2.2.3.1.1.2.1 Reactor Coolant System Leakage Rate

The RCS leakage rate is important in binning core damage sequences because it affects primary system pressure, timing of core damage, fission product retention in the primary system, and hydrogen release rate. There are four distinct leakage rate categories:

- Small LOCA,
- Medium LOCA,
- Large LOCA, and

- Cycling relief valve.

Also, there are two special leakage categories:

- Steam generator tube rupture (SGTR),
- Interfacing systems LOCA.

The small LOCA leakage rate is small enough that SSHR is effective in delaying core damage. Also, for small LOCAs, the primary system pressure will remain high during core damage (expected pressures are in the 1000 psia range) and may lead to a high-pressure melt ejection (HPME) when the reactor vessel fails. For TMI-1, a core melt sequence can be grouped as a small LOCA if it has one of the following break size characteristics:

- 0.007 ft2 to 0.1 ft2 breaks (DE&S 1992)
- Stuck open pressurizer PORV
- Stuck open SRV
- Reactor coolant pump (RCP) seal LOCA
- Steam generator tube ruptures that have an intact secondary system

The medium LOCA leakage rate is a primary system failure that is small enough that the primary pressure will be relatively low (expected pressures are in the 300 to 400 psia range) so that the risk of a HPME accident is significantly reduced. For TMI-1, the medium LOCA size is from 0.1 ft2 to 0.5 ft2 breaks (DE&S 1992).

The large LOCA leakage rate is large enough that the primary system pressure will be very low (expected pressure is less than 200 psia) so that there is little risk of a HPME. For TMI-1, breaks of this size are equal to or larger than 0.5 ft2.

For those primary system ruptures involving pressurized thermal shock (PTS), a rapid cooling transient stress on the reactor vessel while at relatively high pressure, it was assumed that for this condition to occur, some type of primary injection must have been successful in order to achieve the requisite low temperatures at pressure. It was further assumed that the PTS condition would lead to a rupture of a size equivalent to a large LOCA. Therefore, those core damage sequences identified by PTS were categorized as large LOCA with successful injection but failure of early recirculation, i.e., core melt bin 2.

A stuck open or cycling pressurizer relief or safety valve sequence would result in the primary system pressure remaining high (around the PORV set point) such that, if core melt occurred, the risk of a HPME would be high. In general, non-LOCA core melt sequences, such as transient and loss of offsite power (LOOP) sequences, were grouped with the cycling relief valve core melt category.

The leakage category SGTR represents those steam generator tube rupture sequences where there is also a failure of the secondary system. This would result in a direct path for fission product release to the environment with little or no possibility of retention. The scrubbing and retention that is provided by SGTRs with intact steam generators are sufficient to group these with the intact containment plant damage states. For event sequences involving an intact primary system, i.e., no LOCA, and only a tube rupture within a single generator (with failure of the secondary system), core melt bin 16 (Table E.2-2) was chosen to represent this particular scenario.

The interfacing systems LOCA leakage category contains core melt sequences resulting from a rupture in a low-pressure system connected to the primary system. These sequences result in fission product releases that bypass the Reactor Building, but there is still the possibility of some retention in the buildings outside containment.

E.2.2.3.1.1.2.2 Loss of Primary System Makeup Capability

For core damage to occur, multiple failure of mitigation systems must occur. The timing and mode of failure of the primary system makeup capability can affect the characteristics of the PDS. For example, for sequences involving a loss of primary coolant, the timing of core damage is significantly affected by the time at which the safety injection systems fail. Also, the status of safety systems helps to determine whether or not the reactor cavity can be flooded, which impacts the post-core damage analysis. Core damage sequences are grouped into one of the following groups:

- Injection failure – sequences in which injection systems fail initially and do not inject the Borated Waste Storage Tank (BWST) contents into containment.

- Recirculation switchover failure – sequences in which injection systems fail when the BWST contents have been injected into containment and switchover to sump recirculation is attempted.

- Recirculation run failure - sequences in which injection systems switchover to sump recirculation following successful injection, but then fail later due to a run failure of the injection or support systems.

A simplification was made with regard to start and run failures associated with recirculation of water from the containment sump. The dominant early recirculation failures (start failures) were associated with either failure of human actions (including dependent actions) involving operator switchover to sump recirculation prior to emptying the BWST or common cause failure mechanisms, such as valves DH-V-6A, and -6B, or DH-7A, and -7B failing to open, or the DHR pumps both failing to start. All other failures were assumed to be non-dominant start failures or are those that are truly designated as run failures, e.g., heat exchangers plugging, valves failing to remain open, etc.

E.2.2.3.1.1.2.3 Condition of Secondary Side Heat Removal

The status of the SSHR System at the onset of core damage is also an important characteristic of the core damage sequence. SSHR can affect the time of core damage, the primary system pressure, the fission product retention in the primary, and operator actions that might affect core damage progression. There are two categories for the SSHR status:

- SSHR is available.
- SSHR is unavailable.

E.2.2.3.1.1.2.4 Anticipated Transients Without SCRAM

1. For Anticipated Transients without Scram (ATWS) scenarios, the reactor fails to trip in conjunction with another initiating event that prompted the trip signal. Failure to trip the reactor when a valid trip signal occurs results in excessive thermal energy increasing reactor coolant system (RCS) pressure and temperature. The assumptions given below were imposed in order to associate the various ATWS scenarios with the appropriate, or at least conservative, core melt definition from Table E.2-2. Also, since the ATWS event tree (Exelon 2005a) did not address availability of high-pressure injection for certain sequences that lead directly to core damage, failure of early injection was assumed.

2. Core moderator temperature coefficient (MTC) provides a natural feedback control mechanism in which core power is reduced as the moderator (reactor coolant) temperature increases. It is a function of the time in cycle for a given core. For

conditions where there is an unsatisfactory moderator temperature coefficient (e.g., early in a cycle), excessively high RCS pressures may result due to insufficient negative feedback. Although the precise impact on the RCS in such a scenario depends on many other factors and could be benign, this scenario was assumed to result in a large LOCA without the ability to use high-pressure injection (core melt bin 1).

3. For both pressurizer safety valves and PORV unavailability, a large LOCA scenario without high-pressure injection (core melt bin 1) was assumed.

4. For loss of feedwater and inadequate secondary side pressure relief, the core melt bin with cycling primary relief valve without injection (core melt bin 12) was assumed.

5. For those scenarios with explicit failure of high-pressure injection, core melt bin 12 was assumed. SSHR, even if successful, was assumed inadequate for RCS heat removal.

6. For those scenarios involving failure of high-pressure recirculation, core melt bin 14 was assumed (late recirculation failure) instead of bin 13, since it is not clear that this sequence would actually lead to core damage.

E.2.2.3.1.1.3 CONTAINMENT SAFEGUARDS STATES

The containment safeguards state is the second of three characteristics that define the PDS. The containment safeguards state describes the status at the onset of core damage for systems that provide a containment protective function. These systems include the reactor building spray system, and the containment air cooling units (CACUs), which are part of the reactor building emergency cooling system. These systems affect many decisions in the CET and, as a result, they affect accident progression. For example, the containment sprays affect fission product scrubbing, the flooding of the reactor cavity, and the time to reach core damage.

E.2.2.3.1.1.4 CONTAINMENT ISOLATION STATES

The third and final PDS characteristic is the status of containment isolation. Containment isolation is critical to preventing fission product release to the environment. Scoping studies with the MAAP computer code have indicated that there are two categories of containment isolation failure. Small isolation failures allow fission product releases much greater than those for an isolated containment with design leakage. However, the small isolation failures are less severe than early containment failures because they significantly reduce the release rate of fission products. Large isolation failures provide little or no delay in the fission product releases and are essentially the same as early containment failures. For TMI-1, the three containment isolation states are:

1. Isolated - containment is properly isolated.

2. Small isolation failure - containment failure prior to core damage with hole size less than or equal to six inches. A small isolation failure precludes late overpressurization of containment, but does not preclude early overpressurization of containment.

3. Large isolation failure - containment failure prior to core damage with hole sizes larger than six inches. Large isolation failures preclude both early and late overpressurization of containment.

E.2.2.3.1.1.5 PLANT DAMAGE STATE DEFINITION

The PDSs are developed by combining the core melt bins, the containment safeguards states, and the containment isolation states. The PDS definition contains sufficient information about the sequences grouped into it that they may be treated as one. This information is critical input information for solving the CET. The PDS, rather than the individual sequences, determine the branch point frequencies in the CET.

Table E.2-2 lists and describes the 19 core melt bins and Table E.2-14 lists and describes the 18 combinations of containment safeguards states and containment isolation states. PDSs are described by a two-designator variable as follows:

XY

Where: X = core melt bin

Y = containment safeguards and isolation states

The containment safeguards and isolation states were determined by the use of an event tree termed the “bridge” tree, since it bridges the gap between core melt scenarios, plant damage states, and the containment event tree for quantification of release categories. As discussed in Section 2.2.3.1, these PDSs manifest themselves in the model as local portions of CET nodal logic representing the applications of the binning concepts described above. There are no PDS flags associated with the cutsets as is common in other Level 2 model applications.

E.2.2.3.2 Containment Event Tree Purpose

The purpose of the Containment Event Tree (CET) is to quantify containment failure modes and radionuclide releases. Any phenomena that have a significant effect on the radionuclide release fractions or the timing, energy, and duration of the release are included in the tree as a top (header) event. The core damage sequences were categorized into Plant Damage States (PDSs), as determined in Section 2.2.3.1. These core damage sequences are treated as initiating events for the CET. The paths that the PDSs can take through the event tree depend on how they affect the various events modeled. Because the path taken at each top event is based on probabilities and system fault tree evaluations, each PDS will appear at more than one CET end point with varying frequency. Thus, each end point can have more than one PDS state contributing to its total frequency.

E.2.2.3.2.1 CONTAINMENT EVENT TREE DESCRIPTION

Containment event trees, in some cases, have become so complex that the CETs can not be easily represented and are difficult to understand by anyone other than a consequence analyst. The approach used for the TMI-1 analysis relies on converting the large and complex CET into a combination of a small event tree and large decision trees.

In developing the TMI-1 small CET, the only questions included are those that have an effect on the release timing, energy, location, or fission product fractions. When completed, each CET end state represented a separate release category. The CET release category results are presented in Section 2.2.3.3.

After the containment event tree was developed, decision trees using both success and failure logic were developed to determine the probability of the appropriate top event (node) in the CET. This approach was used to avoid the use of NOT gates for sequence success logic, which tended to make the model more complicated and difficult to quantify.

The CET developed for TMI-1 consists of 11 nodal top events that were modeled via the use of Boolean logic, for both success and failure of each branch. The following section defines and describes the CET top events and their associated decision trees. The top events are summarized in Table E.2-15. The logic for each of the CET nodes is cumbersome and complex, so it is not included in this discussion.

To make use of the CET, the important characteristics of the plant's containment must be identified. Three of the more important features that must be considered are the containment ultimate strength capacity, the concrete type, and the reactor cavity arrangement.

The ultimate capacity of containment provides the basis for establishing containment failure probability and failure modes given various accident progression scenarios. TMI-1, is a Babcock & Wilcox PWR with vertical straight-tube (once-through) steam generators that produce superheated steam at constant pressure. The reactor and the nuclear steam supply system are contained within a Reactor Building that is a post-tensioned reinforced-concrete cylinder and dome. The interior of the surface of the building is lined with a one-quarter inch thick welded steel plate to ensure a high degree of leak tightness.

Generally, TMI-1 can be placed into the category of PWR large dry containments, because of their high mean failure pressure, overall containment volume, and open lower containment configuration.

The type of concrete affects the type and properties of gases released during concrete attack. TMI-1's concrete contains a limestone aggregate, which can result in significant non-condensable gas production during concrete ablation.

The reactor cavity geometry affects how (or if) water can reach the cavity during a core damage sequence. The cavity arrangement is important when considering the following phenomena:

- Ex-vessel debris bed coolability
- Potential for direct containment heating
- Ex-vessel steam generation
- Ex-vessel hydrogen or combustible gas production
- Ex-vessel fission product release
- Hydrogen or combustible gas recombination
- Long-term containment overpressurization
- Basemat melt-through
- Potential for debris-liner contact
- Sources of water and pathways to the lower reactor cavity

E.2.2.3.2.2 CONTAINMENT EVENT TREE TOP EVENTS

In this section, the CET top events are defined and described. The CET top events are summarized in Table E.2-15.

CET Top Events	Description
A: Containment Bypass	**Does the release of radionuclides take place within the containment?** Success for this event means that containment is available as a barrier to fission product release. Failure means containment is not available as a barrier to fission product release. The types of accidents that bypass the containment are steam generator tube ruptures (as an initiating event or an induced event) and interfacing-systems LOCA. This top event is further developed using a decision tree model.
B: Containment Isolation	**Does the containment isolate such that: 1) a leakage rate sufficient to cause a substantial increase in radionuclide release to the environment does not occur, and 2) containment pressure response is not significantly affected?** Success for this event means that containment isolation performs its function so that containment becomes a barrier against flow of radionuclides to the environment. Failure means containment integrity is lost and a path is available for radionuclides to reach the environment. This event is concerned with the time at the beginning of the accident sequence (i.e., when isolation occurs) before radionuclides are released to the containment atmosphere.
C: Isolation Failure Size	**Is the isolation failure equivalent to a small hole size in containment?** Success for this event means that the isolation failure is small, i.e., system top event SMALL-ISO. For the TMI-1 analysis, a small isolation failure is defined as a six-inch equivalent diameter hole. Isolation failures of this type allow some time for holdup inside containment where natural removal mechanisms (e.g., plateout) will reduce radionuclide concentrations. Failure of this event implies that the isolation failure is not small, i.e., system top event LARGE-ISO, and allows little or no holdup in containment. Both small and large isolation failures preclude late overpressurization. All other containment overpressure sequences (hydrogen burns, direct containment heating, etc.) are prevented only by large isolation failures.
D: Auxiliary Building Release	**Does the fission product release pass through the Auxiliary Building?** Success for this event means that the fission product release will pass through the Auxiliary Building. This release path is the result of an interfacing-system LOCA or an isolation failure to the Auxiliary Building. Failure for this event means that the fission product release does not pass through the Auxiliary Building. A release path that bypasses the Auxiliary Building is a pathway directly to the environment. This top event is applicable only if containment is not isolated or is bypassed. Determination of success or failure depends on the type of isolation failure, where the fission products are released, and the PDS. For example, a SGTR would be a failure, while most interfacing systems LOCAs would be a success.
E: Early Containment Failure	**Does the containment remain intact until long after reactor vessel failure (i.e., a time period which allow sufficient time for fission product settling)?** Success for this event means that containment remains intact long after reactor vessel failure. Failure for this event means that containment has failed prior to or within the time required for fission product settling and decay of short-lived isotopes. This time period is typically defined as five hours after reactor vessel failure.
F: Late Containment Failure	**Does the containment remain intact throughout the entire core melt sequence?** Event success means that the containment remains intact throughout the entire core melt sequence. Releases to the environment after this point, if any, are due to normal containment leakage or basemat melt-through. Failure of this event means that containment fails late in the core melt sequence due to an overpressurization event.

CET Top Events	Description
G: Benign Containment Failure	**Is late containment failure benign?** Success for this event means that a late overpressurization results in a benign containment failure, i.e., leak-before-break. This failure mode is described as a series of small cracks that develop in the containment structure such that further pressurization does not occur. Failure of this event means that a late overpressurization results in a catastrophic containment failure, which would cause containment to depressurize rapidly. This is strictly a function of the containment type, and is quantified identically for all PDSs.
H: Ex-Vessel Release Of Fission Products	**Is a coolable debris bed established outside the reactor vessel so that significant ex-vessel fission product releases do not occur?** Success for this event means that a coolable debris bed is established in the reactor cavity or the containment, preventing an ex-vessel release. Failure means that a coolable debris bed is not established, allowing the corium to attack the concrete (producing non-condensable gases) and resulting in an ex-vessel release. The ex-vessel release involves a significant amount of tellurium and other fission products.
I: Containment Basemat Failure	**Is a coolable debris bed established in the reactor cavity to prevent containment failure from basemat melt-through?** Success for this event means that the debris bed in the cavity is cooled, and concrete ablation is stopped. Failure means that the debris bed is not cooled and ablates concrete until the basemat is failed.
J: Revaporization Release	**Is a revaporization release of volatile fission products at or near the time of containment failure prevented?** Success for this event means that large amounts of volatile fission products have not revaporized and are not available for release when containment overpressurizes. Failure means that volatile fission products that were deposited in the RCS have revaporized and are available to be released in large amounts when containment fails. Revaporization is only considered for late catastrophic containment failures. Early containment failures release fission products at or shortly after reactor vessel failure resulting in high release fractions. The effects of revaporization, if any, would not be seen for this failure mode. Late containment failures, however, provide time for radionuclide removal from the atmosphere by various methods. As a result, release fractions at containment failure are lower so that revaporization of fission products will have a larger impact. Revaporization is not considered for benign failures of containment since the pressure remains high due to the slow depressurization of containment. Since the pressure remains high in containment, revaporization is unlikely to occur.
K: Fission Product Scrubbing	**Are fission product removal mechanisms available to reduce the amount of radionuclides released to the environment?** Success for this event means that the fission products are scrubbed by some method prior to release to the environment. These mechanisms include: - Containment scrubbing (e.g., sprays) - Auxiliary Building scrubbing (e.g., plateout) - Steam Generator scrubbing (e.g., water pool release) Failure for this event means the fission products are not scrubbed prior to release to the environment by any method.

E.2.2.3.3 Release Categories and Source Terms

The endpoint of the CET contains two major pieces of information, which are the release frequency and the release category designation. The parameters that define a release category and are important in the analysis of offsite consequences are:

1. Time of release
2. Duration of release
3. Energy of release
4. Warning time for evacuation
5. Isotopic fractions released to the environment

Each CET end point is capable of describing a unique sequence with potentially unique release characteristics. For TMI-1, 39 release categories were identified in the CET with most endpoints having a unique release category designation. A numbering scheme is used to separate major categories:

- 1 = Containment Bypass with Auxiliary Building Bypass
- 2 = Interfacing-Systems LOCA
- 3 = Large Isolation Failures
- 4 = Small Isolation Failures
- 5 = Early Containment Failure
- 6 = Late Containment Failure (Catastrophic)
- 7 = Late Containment Failure (Benign)
- 8 = Basemat Melt-Through
- 9 = No Containment Failure

Different sequences within these major categories were given a designation such as 1.01, 1.02, 2.01, etc. in order to distinguish between specific details of the containment response. The 39 TMI-1 release categories are summarized in Table E.2-16.

The MAAP thermal hydraulics code was used to analyze the plant specific containment responses for each of the CET sequences. The 39 TMI-1 release categories were then reviewed in order to determine how they could be grouped for the assignment of source terms. It is possible to develop source terms for every release category in the CET, but in many cases, the results are so similar that maintaining unique source terms for every release category does not provide any measurable benefit. As a result, release categories with similar traits were grouped together and a single source term was used to represent the entire group to streamline the Level 3 analysis. For TMI-1, nine major source term groups identified above were found to be an adequate structure for segregating the source terms. The table below correlates the major source term groups to the source term designators and provides basic descriptions of the representative sequence established for each source term group:

Representative Sequence Descriptions for Source Term Groups

Release Category Group	Source Term Designator	General Description of Contributing Sequences
1: Containment Bypass w/ Aux Bldg Bypass	SGTR	This event is initiated with a double ended failure of a steam generator tube with the SG safety valve failed open. All injection is assumed unavailable. Emergency feedwater is available.
2: ISLOCA	ISLOCA	This event is initiated with a small break outside of containment followed by failure of injection. Emergency feedwater is available.
3: Large Isolation Failure	ISO-LG	This scenario is represented by a loss of main feedwater followed by a failure of all injection. A large containment isolation failure is assumed to occur at time zero. Emergency feedwater operates successfully for a period of 6 hours. At 15 minutes into the event, 42 gpm seal leakage is assumed per loop. Core damage occurs at 9.4 hours into the event followed by failure of the hot leg due to creep rupture 36 minutes later. Vessel breach occurs at 16 hrs.
4: Small Isolation Failure	ISO-SM	This scenario is represented by a loss of main feedwater followed by a failure of all injection. A small containment isolation failure is assumed to occur at time zero. Emergency feedwater is assumed unavailable. At 15 minutes into the event, 42 gpm seal leakage is assumed per loop. Core damage occurs at 50 minutes into the event followed by failure of the hot leg due to creep rupture 36 minutes later. Vessel breach occurs at 6 hrs.
5: Early Containment Failure	EARLY	This scenario is represented by a Station Blackout. Emergency feedwater operates successfully for a period of 6 hours. At 15 minutes into the event, 42 gpm seal leakage is assumed per loop. Core damage occurs at 9 hours into the event. Vessel breach occurs at 11.7 hrs. It is assumed that containment failure occurs at the time of vessel breach.

Representative Sequence Descriptions for Source Term Groups

Release Category Group	Source Term Designator	General Description of Contributing Sequences
6: Late Containment Failure (catastrophic)	LATE-LG	This scenario is represented by a loss of main feedwater followed by a failure of all injection. Emergency feedwater operates successfully. At 15 minutes into the event, 42 gpm seal leakage is assumed per loop. Core damage occurs at 26 hours into the event followed by failure of the hot leg due to creep rupture 40 minutes later. Vessel breach occurs at 34.8 hrs. The containment fails due to overpressure at 70 hours into the event with an assumed large failure area, resulting a rapid depressurization of containment.
7: Late Containment Failure (benign)	LATE-SM	This scenario is represented by a Station Blackout. Emergency feedwater operates successfully for a period of 6 hours. At 15 minutes into the event, 42 gpm seal leakage is assumed per loop. Core damage occurs at 9 hours into the event followed by failure of the hot leg due to creep rupture 50 minutes later. Vessel breach occurs at 16.5 hrs. Containment sprays are assumed to be recovered at 24 hours into the event. The core debris remains covered with water, however, without heat removal, the containment fails due to overpressure at 52 hours into the event. The breach area is assumed to be represented by a leak-before-break and results in a very slow containment depressurization.
8: Basemat Melt-Through	BMMT	This scenario is represented by a loss of main feedwater followed by a failure of all injection. Emergency feedwater operates successfully. At 15 minutes into the event, 42 gpm seal leakage is assumed per loop. Core damage occurs at 26 hours into the event followed by failure of the hot leg due to creep rupture 40 minutes later. Vessel breach occurs at 34.7 hrs. All of the core debris is forced to remain in the reactor cavity in order to accelerate the amount of core concrete attack. When concrete erosion has exceeded 6 feet, containment failure is assumed to occur with a representative failure area equal to 1 ft2.
9: No Containment Failure	INTACT	This scenario is represented by a loss of main feedwater followed by a failure of all injection. Emergency feedwater operates successfully. At 15 minutes into the event, 42 gpm seal leakage is assumed per loop. Core damage occurs at 26 hours into the event followed by failure of the hot leg due to creep rupture 40 minutes later. Vessel breach occurs at 34.6 hrs. Successful operation of containment sprays and fan coolers prevents containment overpressure failure long term.

Table E.2-17 provides additional accident progression information for the representative sequences described above, including the time to core damage, time to containment failure, and notable release fractions.

In some cases, there were competing contributors to a release category group with measurable differences in some of the release fractions (e.g., scrubbed vs. unscrubbed releases). The representative source term for the release category is typically chosen based on the largest frequency, but when the consequences of a source term with a smaller frequency are more severe, the more severe source term is used if it is believed that the group would otherwise be underrepresented.

The source terms that are used as input to the TMI-1 Level 3 model are a combination of radionuclide release fractions, the timing of the radionuclide release relative to the declaration of a general emergency, and the frequencies at which the releases occur. This combination of information is used in conjunction with other TMI-1 site characteristics in the Level 3 model to evaluate the consequences of a core damage event. Table E.2-18 provides a summary of the TMI-1 source term information, which includes the following:

- MAAP case identifier (for reference),
- Airborne release for each of the fission product groups provided my MAAP,
- Start time of the airborne release (measured from the time of accident initiation),
- End time of the airborne release (measured from the time of accident initiation).

Note that the individual release category frequencies are provided in Table E.2-16.

E.2.2.4 TMI MODEL RESULTS

Figure E.2-1 is a pie-chart showing the initiating event contribution to internal events CDF from the quantification of the TMI PRA 2004 Revision 2 model at a truncation limit of 1E-11. Table E.2-19 presents the ranked list of initiating events by their contribution to CDF. As can be seen in the table, about a third of the total CDF comes from loss of offsite power events. About one-half of CDF is due to a combination of transients and very small break (<1.0" diameter) and small break LOCAs (1"-4.3" in diameter). The next largest single contributor is loss of nuclear services river water, which accounts for about 16% of CDF. It is interesting to note that the large LOCA initiator, which represents the design basis accident for TMI-1, accounts for less than 1% of the total CDF. Figure E.2-2 is a bar chart displaying the system importance rankings (basically by Fussell-Vesely). Onsite emergency electrical power and offsite power sources dominate the contributions to CDF.

The TMI PRA includes a Level 2 model from which each of the release category frequencies can be calculated. The Release Category results are based on the TMI 2004 Revision 2 model, which was completed in 2007. Table E.2-20 presents the top initiating events for each of the release categories.

With regard to Large Early Release frequencies (LERF), the TMI LERF is estimated at 3.0E-6/year (12.7% of CDF). These results are slightly higher when compared to other PWRs with large dry containments that generally fall in the range from 3% to 10% of CDF. The contributions to LERF consist of the following release categories:

RC1-02	RC3-03	RC4-04
RC2-01	RC3-04	RC4-05
RC2-02	RC3-05	RC4-06
RC2-03	RC3-06	RC4-07
RC2-04	RC4-01	RC4-08
RC3-01	RC4-02	RC5-01
RC3-02	RC4-03	RC5-02

E.2.3 EXTERNAL FLOODING MODEL

The External Flooding model developed for the IPEEE was a simplified, Level 1 PRA evaluation. While there are words in the IPEEE that indicate it is a Level 2 analysis, the depth of any containment performance analysis that was carried out was not robust enough to support the SAMA analysis. In order to provide a means of evaluating the external flooding based SAMAs, it was necessary to develop representative source terms and release frequencies for the most important flooding contributors. This process is described in Sections E.2.3.1 and E.2.3.2.

E.2.3.1 CORE DAMAGE SEQUENCE IDENTIFICATION

The core damage sequences developed for the external flooding model include three major groups:

- Floods with elevations greater than 310 feet mean sea level (msl)
- Floods with elevations between 305 and 310 feet msl,
- Floods with elevations less than 305 feet msl.

Of these groups, the floods above 310 feet and those below 305 feet are each represented by a single core damage sequence. The floods between 305 and 310 feet are represented by six sequences that were quantified using an event tree developed specifically for the IPEEE external flooding evaluation. The descriptions and frequencies of these sequences are summarized in Table E.2-21.

E.2.3.2 LEVEL 2 BINNING OF EXTERNAL FLOODING SCENARIOS

In order to provide the input required for the Level 3 analysis of the external flooding scenarios, it was necessary to use the information in the IPEEE to estimate the plant response after core damage. Two separate processes were required to address the different flood scenarios. For the 305' to 310' msl floods and the floods greater than 310' msl, the flooding sequences were analyzed and direct correlations between the core damage sequences and the source terms were developed. For floods below 305' msl, the containment performance characteristics for LOOP events were used to determine the releases given the similarity in the events.

E.2.3.2.1 Source Term Correlation for External Flood Sequences Over 305' msl

In order to determine the quantitative distribution of the flooding sequences among the TMI-1 source terms, it was necessary to make assumptions about the reactor status based on the information available in the IPEEE, determine which sequences should be binned to specific source terms, and then calculate the conditional probabilities of the relevant CET sequences.

For cases where the transition to cold shutdown was not completed before accident initiation, a specific set of valves corresponding to a small pathway would be left open and a conditional probability of 1.0 was assigned to the "Iso Sm" source term (small isolation failure). These sequences are all from the IPEEE 305' to 310' msl flood cases and include:

- Sequence "B"
- Sequence "D"
- Sequence "E"
- Sequence "F"

The remaining sequences are evolutions in which the plant is successfully transitioned to cold shutdown before the onset of accident conditions. These sequences include:

- Floods >310’ msl
- 305’ to 310’ msl flood sequences “A”
- 305’ to 310’ msl flood sequences “C”

In these cases, there are a number of ways in which the containment could fail and the Level 2 CET was used to estimate the conditional failure probabilities assuming that containment isolation was initially successful. The conditional probabilities for theses sequences were calculated by quantifying specific nodal events in the CET that were chosen because they helped establish source term bins. Table E.2-22 summarizes the binning characteristics of each of these nodes:

A simplified version of the TMI-1 CET (see Figure E.2-3) has been developed using only these nodes to graphically depict the binning process and to document the fractional division of the relevant external flooding sequences among the source terms. Additional details related to the CET development and uses are provided in the TMI-1 Containment Event Tree Analysis Notebook (Exelon 2007b).

E.2.3.2.2 Source Term Correlation for External Flood Sequences Below 305’ msl

External floods below 305’ msl do not have an impact on TMI-1 other than any LOOP event that may accompany the flood conditions, which is an insight that was used to estimate the containment performance and release characteristics for these events. The PRA model was quantified with all initiating events other than LOOP set to zero in order to simulate the conditions expected to exist for external floods below 305’ msl. The resulting release category frequencies were used to define the generic fractional distribution of these flood events among the 39 release categories.

Review of the release category frequencies demonstrated that 95% of the risk is associated with only 8 of the release categories. In order to simplify external flooding calculations, only these 8 release categories are used in the external flooding quantifications. The 5.3 percent contribution from the non-used release categories has been accounted for by adding 5.31E-02 to the total for RC5-01, the “Early” release bin, which is conservative for the purposes of the SAMA analysis. The following table summarizes the RC fractions used in the quantifications:

RC name	Probability	Fraction of total	Correction to account for non-used RCs	Revised RC fractions
1-02	1.59E-06	6.71E-02	0	6.71E-02
4-04	3.16E-07	1.33E-02	0	1.33E-02
5-01	7.39E-07	3.12E-02	5.31E-02	8.43E-02
7-03	7.45E-07	3.15E-02	0	3.15E-02
7-04	2.89E-07	1.22E-02	0	1.22E-02
8-01	3.19E-06	1.35E-01	0	1.35E-01
9-01	1.32E-05	5.57E-01	0	5.57E-01
9-03	2.36E-06	9.96E-02	0	9.96E-02
Totals		9.47E-01	5.31E-02	1.00E+00

The source terms for these release categories are provided in Section E.2.2.3.3.

E.2.3.2.3 External Flooding Binning Summary

The desired product of the External Flooding binning process is a set of frequencies that are correlated to the TMI-1 source terms so that they can be used with the Level 3 model results to quantify the consequences of External Flooding accidents. The consequence results are then used in the cost benefit analysis, as described in Section E.4. Table E.2-23 summarizes the source term specific frequencies for each of the TMI-1 External Flooding sequences.

E.2.4 TMI-1 PEER REVIEW SUMMARY

The TMI-1 internal events PRA received a formal industry PRA Peer Review in August 2000. The final report was issued in March, 2001. "It was the general assessment of the peer review team that the Three Mile Island PRA can be effectively used to support applications involving risk significant determinations supported by deterministic analysis, once the technical issues and recommendations for enhancements that are noted in the element summaries and Fact and Observation Sheets are addressed to an appropriate level of quality."

Table E.2-24 contains the grades of the individual PRA Elements recorded by the Peer Review Team.

All 'A' and 'B' F&Os are closed with exception of one 'B' level observation. F&O SY-21 relates to the need for independent technical and system engineer reviews of system notebooks. Most of the system notebooks have not been systematically reviewed by the system engineers.

The Peer Review Report also credits items of strength in the TMI PRA. Some of the strengths were:

- Treatment of dependencies in sequence and system models. There was excellent treatment and documentation of system functional dependencies and physical dependencies evidenced by system dependency matrices.

- Room heatup tests to support model. To resolve some earlier uncertainties regarding the impact of loss of room cooling to the electrical switchgear rooms and other areas, TMI conducted test to verify the success criteria for associated HVAC systems.

- Excellent ISLOCA treatment. The treatment of interfacing system LOCA sequences, including the systematic review of candidate pathways, quantification of initiating event frequencies, evaluation of response of low pressure systems to overpressure, and treatment of containment isolation interfaces, was state of the art and well conducted.

E.3 LEVEL 3 PRA ANALYSIS

This section addresses the critical input parameters and analysis of the Level 3 portion of the probabilistic risk assessment. In addition, Section E.7.3 summarizes a series of sensitivity evaluations to potentially critical parameters.

E.3.1 ANALYSIS

The MACCS2 code (NRC 1998a) is used to perform the Level 3 probabilistic risk assessment (PRA) for the Three Mile Island Nuclear Generating Plant. Three Mile Island site specific parameters are used for population distribution and economic parameters. Plant-specific release data included the time-dependent nuclide distribution of releases and release frequencies. The behavior of the population during a release (evacuation parameters) is based on plant and site-specific set points. Other input parameters given with the MACCS2 “Sample Problem A”, formed the basis for the present analysis. These data are used in combination with site-specific meteorology to simulate the probability distribution of impact risks (both exposures and economic effects) to the surrounding 50-mile radius population as a result of the release accident sequences at Three Mile Island.

E.3.2 POPULATION

The population surrounding the Three Mile Island site is estimated for the year 2034.

Population projections within 50 miles of Three Mile Island are determined using SECPOP2000, (NRC 2003) utilizing a geographic information system (GIS). U.S Census block-group level population data is allocated to each sector based on the area fraction of the census block-groups in that sector. U.S. Census data from 1990 and 2000 are used to determine a ten year population growth factor for each of the 50-mile radius rings. The population growth factor for each ring is applied uniformly to all sectors in the ring to calculate the year 2034 population distribution.

The distribution is given in terms of population at distances to 1, 2, 3, 4, 5, 10, 20, 30, 40 and 50 miles from the plant and in the direction of each of the 16 compass points (i.e., N, NNE, NE……NNW).

The total year 2034 population for the 160 sectors (10 distances × 16 directions) in the region is estimated as 3,609,252. The ten year population growth factor (in parenthesis) and distribution of the population is given for the 10-mile radius from Three Mile Island and for the 50-mile radius from Three Mile Island in Tables E.3-1 and E.3-2, respectively.

E.3.3 ECONOMY

MACCS2 requires certain economic data (fraction of land devoted to farming, annual farm sales, fraction of farm sales resulting from dairy production, and property value of farm and non-farm land) for each of the 160 sectors. These values are calculated using the SECPOP2000 code (NRC 2003). SECPOP2000 utilizes economic data from the U.S. Department of Agriculture, "1997 Census of Agriculture" (USDA 1998) and from other 1998 and 1999 data sources. Economic values for up to 97 economic zones are calculated and allocated to each of the 160 sectors.

In addition, generic economic data that are applied to the region as a whole are revised from the MACCS2 sample problem input when better information is available. These revised parameters include per diem living expenses (applied to owners of interdicted properties and relocated populations), relocation costs (for owners of interdicted properties), and value of farm and non-farm wealth. These values are updated to the year 2006 value using the Consumer Price Index ratio.

Three Mile Island MACCS2 economic parameters include the following:

Three Mile Island MACCS2 Economic Parameters

Variable	Description	Three Mile Island Value
DPRATE(1)	Property depreciation rate (per yr)	0.2
DSRATE(1)	Investment rate of return (per yr)	0.12
EVACST(2)	Daily cost for a person who has been evacuated ($/person-day)	48.72
POPCST(2)	Population relocation cost ($/person)	9022.00
RELCST(2)	Daily cost for a person who is relocated ($/person-day)	48.72
CDFRM0(2)	Cost of farm decontamination for various levels of decontamination ($/hectare)	1015.00 2256.00
CDNFRM(2)	Cost of non-farm decontamination per resident person for various levels of decontamination ($/person)	5413.00 14435.00
DLBCST(2)	Average cost of decontamination labor ($/man-year)	63155.00

Three Mile Island MACCS2 Economic Parameters

Variable	Description	Three Mile Island Value
VALWF0[3]	Value of farm wealth ($/hectare)	3311.00
VALWNF[3]	Value of non-farm wealth ($/person)	110473.00

(1) DPRATE and DSRATE are based on NUREG/CR-4551 value (NRC 1990).
(2) These parameters for Three Mile Island use the NUREG/CR-4551 value (NRC 1990), updated top the 2006 CPI value.
(3) VALWF0 and VALWNF are based on SECPOP2000 values for Three Mile Island, updated to the 2006 CPI value.

E.3.4 FOOD AND AGRICULTURE

Food ingestion is modeled using the COMIDA2 methodology consistent with Sample Problem A. The COMIDA2 model utilizes national based food production parameters derived from the annual food consumption of an average individual such that site specific food production values are not utilized. The fraction of population dose due to food ingestion is typically small compared to other population dose sources. For Three Mile Island, approximately five percent of the total population dose is due to food ingestion.

E.3.5 NUCLIDE RELEASE

MACCS2 requires input for 60 radionuclides. The core inventory at the time of the accident is based on a plant specific ORIGEN2.1 calculation for a 24 month refueling cycle (obtained from C-1101-900-E-220-178, Rev. 0, 2002). Table E.3-3 provides the MACCS2 Three Mile Island core inventory.

Three Mile Island nuclide release categories are related to the MACCS categories as shown in Table E.3-4. All releases are modeled as occurring at 51.6 meters (top of the Reactor Building). The thermal content of each of the releases are assumed to be 1.0E+07 watts based on values provided in Sample Problem A and NUREG/CR-4551 (NRC 1990). The release associated with each source term is modeled as two or three individual plume segments to capture nuclide release changes as a function of time.

Two nuclide release sensitivity cases were performed to determine the effect of release height and thermal content assumptions. One sensitivity case modeled the releases occurring at ground level (0.0 meters). The second sensitivity case modeled the thermal content of each release to be the same as ambient (i.e., buoyant plume rise is not modeled). The results are discussed in Section E.7.3.

E.3.6 EVACUATION

Reactor scram signal begins each evaluated accident sequence. A General Emergency is declared when plant conditions degrade to the point where it is judged that there is a credible risk to the public. Therefore, the timing of the General Emergency declaration is sequence specific and ranges from 48 minutes to 26 hours for the release sequences evaluated.

The MACCS2 User's Guide input parameters of 95 percent of the population within 10 miles of the plant [Emergency Planning Zone (EPZ)] evacuating and 5 percent not evacuating are employed. These values have been used in similar studies (e.g., Hatch, Calvert Cliffs, (SNOC 2000) and (BGE 1998)) and are conservative relative to the NUREG-1150 study, which assumed evacuation of 99.5 percent of the population within the EPZ. The evacuees are assumed to begin evacuating 90 minutes after a General Emergency has been declared and are evacuated at an average radial speed of 1.18 miles per hour (0.53 m/sec). This speed is the time weighted value accounting for season, day of the week, time of day, weather conditions, and special events. The evacuation time weighted average of 600 minutes is for the full 0-10 mile EPZ, an assumed 15 minute notification time, 15 minutes for evacuation preparation, and 60 minutes average departure time. (ETI 2003)

One evacuation sensitivity case is performed to determine the impact of evacuation assumptions. The sensitivity case reduced the evacuation speed by a factor of two (0.26 m/sec). The results are discussed in Section E.7.3.

E.3.7 METEOROLOGY

Annual Three Mile Island meteorology data from year 1998 is used in MACCS2 for the base case results. The year 1998 meteorological data set is utilized for the Three Mile Island base case MACCS2 analysis based on the fact that the year 1998 provided the most complete data set, the highest population dose risk and offsite economic cost risk, and is judged to be the most conservative.

Year 1998, 1999, and 2000 meteorology data for the Three Mile Island site contains wind speed, wind direction, and stability data. Site specific precipitation data was not included. The 1998 Three Mile Island meteorological data set contained 39 total hours of missing data, representing 0.45% of the hourly readings. The 1999 and 2000 Three Mile Island meteorological data sets contained 54 and 23 total hours of missing data, respectively, representing 0.62% and 0.26% of the hourly readings. Of the three data sets used the 1998 data set is the only data set that did not include any gaps of missing data of more than two hours. Therefore, it is judged the year 1998 provided the most complete data set.

The year 1998 meteorological data set contained several one or two hour gaps of missing data (39 hours, 0.45%). Traditionally, up to 10% of missing data is considered acceptable. All of the missing gaps consisted of two hours or less and interpolation was used to fill in the missing meteorological data. It is noted that MACCS2 results used in the SAMA analysis are the statistical mean of 384 weather sequences (each sequence contains 120 hours of data) chosen at random from pre-sorted weather bins. Due to the large number of samples analyzed, the adjustment of any particular weather sequence has negligible impact on the mean results.

Three Mile Island MACCS2 analysis evaluated three meteorological data sets (Calendar years 1998, 1999, and 2000) to ensure that the meteorological data set used in the analysis is adequate. The use of the most conservative data set (year 1998) accounts for any weather sequences that may have been misrepresented by substitute data. Based on the multiple years analyzed, minimum data gaps in the year 1998 meteorological data, and the sampling methodology used, the reported mean results are judged acceptable and appropriate for use in averted cost risk calculations.

Meteorological data is prepared for MACCS2 input as follows:

1. Wind speed, wind direction, and atmospheric stability data is provided from the site. Precipitation data from the Middletown/Harrisburg Airport is utilized.

2. If a brief period (i.e., < 6 hr.) of missing data exists, interpolation is used between hours.

3. For larger data voids (i.e., > 6 hr.), data from the previous or following day is utilized to fill data gaps (for the same time of day).

4. Atmospheric mixing heights are specified for morning and afternoon. These values were taken from the document *Mixing Heights, Windspeeds, and Potential for Urban Air Pollution throughout the Contiguous United States* (EPA 1972).

   This source defined morning as being the four-hour period from 0200 to 0600 Local Standard Time and afternoon as being the four-hour period from 1200 to 1600 Local Standard Time.

   The Code Manual for MACCS2: Volume 1 (from Appendix A, pages A-1 and A-2) states the following:

"The first of these two values corresponds to the morning mixing height and the second to the afternoon height. In the current implementation, the larger of these two values and the value of the boundary weather mixing height is used by the code."
"In its present form, that atmospheric model implemented in MACCS2 does not allow a change in the mixing layer to occur during transport of the plume. Mixing layer height is assumed to be constant and therefore only a single value is used by the code."

For the Three Mile Island MACCS2 analyses, these conditions mean that, only the afternoon mixing height is used since it is larger than the morning mixing height. Note that the boundary weather mixing height, wind speed and stability category are only used when there is no meteorological data. These fixed boundary weather values are ignored by the code when an hourly meteorological data file is supplied by the user, as was the case in the MACCS2 runs for Three Mile Island.

As noted above, site meteorological data for years 1999 and 2000 are also evaluated as sensitivity cases to ensure year 1998 data is an appropriate data set. The results are discussed in Section E.7.3.

E.3.8 MACCS2 RESULTS

Tables E.3-5 shows the mean off-site doses and economic impacts to the region within 50 miles of Three Mile Island for each of nine source term groups evaluated using MACCS2. These impacts are multiplied by the annual frequency for each release category and then summed to obtain the dose-risk and offsite economic cost-risk (OECR) for the TMI-1 internal events initiators. Table E.3-6 provides the results for the non-zero release categories.

Table E.3-7 summarizes the base case results for the sequence specific external flooding contributions based on the source term frequencies identified in Section E.2.3.2.3 and the source term specific dose and cost results identified in Table E.3-5.

E.4 BASELINE RISK MONETIZATION

This section explains how Exelon calculated the monetized value of the status quo (i.e., accident consequences without SAMA implementation). Exelon also used this analysis to establish the maximum benefit that could be achieved if all on-line risk were eliminated.

E.4.1 OFF-SITE EXPOSURE COST-RISK

The baseline annual off-site exposure risk was converted to dollars using NRC's conversion factor of $2,000 per person-rem, and discounted to present value using NRC standard formula (NRC 1997a):

$W_{pha} = C \times Z_{pha}$

Where:

W_{pha} = monetary value of public health risk after discounting

C = $[1-\exp(-rt_f)]/r$

t_f = years remaining until end of facility life = 20 years

r = real discount rate (RDR) (as fraction) = 0.03 per year

Z_{pha} = monetary value of public health (accident) risk per year before discounting ($ per year)

The Level 3 analysis showed an annual off-site population dose risk of 32.61 person-rem. The calculated value for C using 20 years and a 3 percent discount rate is approximately 15.04. Therefore, calculating the discounted monetary equivalent of accident dose-risk involves multiplying the dose (person-rem per year) by $2,000 and by the C value (15.04). The calculated off-site exposure cost-risk is estimated to be $980,884.

E.4.2 OFF-SITE ECONOMIC COST-RISK

The Level 3 analysis showed an annual off-site economic cost-risk of $112,259. Calculated values for off-site economic cost-risks caused by severe accidents over the license renewal period must be discounted to present value as well. This is performed in the same manner as for public health risks and uses the same C value. The resulting value is $1,688,328.

E.4.3 ON-SITE EXPOSURE COST-RISK

Occupational health was evaluated using NRC methodology that involves separately evaluating immediate and long-term doses (NRC 1997a).

For immediate dose, NRC recommends using the following equation:

Equation 1:

$$W_{IO} = R\{(FD_{IO})_S - (FD_{IO})_A\}\{[1 - \exp(-rt_f)]/r\}$$

Where:

W_{IO} = monetary value of accident risk avoided due to immediate doses, after discounting

R = monetary equivalent of unit dose ($2,000 per person-rem)

F = accident frequency (2.37E-05 events per year)

D_{IO} = immediate occupational dose [3,300 person-rem per accident (NRC estimate)]

$_S$ = subscript denoting status quo (current conditions)

$_A$ = subscript denoting after implementation of proposed action

r = RDR (0.03 per year)

t_f = years remaining until end of facility life (20 years).

Assuming F_A is zero, the best estimate of the immediate dose cost is:

$$W_{IO} = R\,(FD_{IO})_S\{[1 - \exp(-rt_f)]/r\}$$

$$= 2{,}000 * 2.37\text{E-}05 * 3{,}300 * \{[1 - \exp(-0.03 * 20)]/0.03\}$$

$$= \$2{,}352$$

For long-term dose, NRC recommends using the following equation:

Equation 2:

W_{LTO} = $R\{(FD_{LTO})_S - (FD_{LTO})_A\} \{[1 - \exp(-rt_f)]/r\}\{[1 - \exp(-rm)]/(rm)\}$

Where:

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

D_{LTO} = long-term dose [20,000 person-rem per accident (NRC estimate)]

m = years over which long-term doses accrue (as long as 10 years)

Using values defined for immediate dose and assuming F_A is zero, the best estimate of the cost associated with long-term dose is:

W_{LTO} = $R (FD_{LTO})_S \{[1 - \exp(-rt_f)]/r\} \{[1 - \exp(-rm)]/(rm)\}$

= $2,000*2.37E-05 *20,000*\{ [1 - \exp(-0.03*20)]/0.03\} \{[1 -\exp(-0.03*10)]/(0.03*10)\}$

= $12,318

The total occupational exposure is then calculated by combining Equations 1 and 2 above. The total accident related on-site (occupational) exposure cost-risk (W_O) is:

W_O = $W_{IO} + W_{LTO}$ = ($2,352 + $12,318) = $14,670

E.4.4 ON-SITE CLEANUP AND DECONTAMINATION COST-RISK

The total undiscounted cost of a single event in constant year dollars (C_{CD}) that NRC provides for cleanup and decontamination is $1.5 billion (NRC 1997). The net present value of a single event is calculated as follows. NRC uses the following equation to integrate the net present value over the average number of remaining service years:

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

Where:

PV_{CD} = net present value of a single event

C_{CD} = total undiscounted cost for a single accident in constant year dollars

r = RDR (0.03)

m = years required to return site to a pre-accident state

The resulting net present value of a single event is $1.3E+09. The NRC uses the following equation to integrate the net present value over the average number of remaining service years:

U_{CD} = $[PV_{CD}/r][1\text{-}\exp(-rt_f)]$

Where:

PV_{CD} = net present value of a single event ($1.3E+09)

r = RDR (0.03)

t_f = 20 years (license renewal period)

The resulting net present value of cleanup integrated over the license renewal term, $1.95E+10, must be multiplied by the total CDF (2.37E-05) to determine the expected value of cleanup and decontamination costs. The resulting monetary equivalent is $461,912.

E.4.5 REPLACEMENT POWER COST-RISK

The long-term replacement power cost-risk was determined following NRC methodology in NUREG/BR-0184 (NRC 1997a). The net present value of replacement power for a single event, PV_{RP}, was determined using the following equation:

PV_{RP} = $[1.2\times10^{8}(\$\text{-yr})/r] * [1 - \exp(-rt_f)]^2$

Where:

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

r = RDR (0.03)

t_f = 20 years (license renewal period)

To attain a summation of the single-event costs over the entire license renewal period, the following equation is used:

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

Where:

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

After applying a correction factor to account for TMI-1 size relative to the generic reactor described in NUREG/BR-0184 (i.e., 875 megawatt electric/910 megawatt electric) the replacement power costs are determined to be 5.31E+09 ($-year). Multiplying this value by the CDF (2.37E-05) results in a replacement power cost-risk of $125,917.

E.4.6 MAXIMUM AVERTED COST-RISK

The TMI-1 Maximum Averted Cost-Risk (MACR) is the total averted cost-risk if all internal and external events risk associated with on-line operation were eliminated. This is calculated by summing the following components:

Maximum Internal Events Averted Cost-Risk

Maximum External Flooding Averted Cost-Risk

Maximum External Events Averted Cost-Risk (excluding external flooding)

As described in Section E.5.1, the MACR is used in the SAMA identification process to determine the depth of the importance list review. In addition, the MACR is used in the Phase I analysis as a means of screening SAMAs.

The following subsections provide a description of how each of these components are calculated and used together to obtain the TMI-1 MACR.

E.4.6.1 INTERNAL EVENTS MAXIMUM AVERTED COST-RISK

The maximum internal events averted cost-risk is the sum of the contributors calculated in Sections E.4.1 through E.4.5:

Maximum Averted Internal Events Cost-Risk

Off-site exposure cost-risk	=	$980,884
Off-site economic cost-risk	=	$1,688,328
On-site exposure cost-risk	=	$14,670
On-site cleanup cost-risk	=	$461,912
Replacement Power cost-risk	=	$125,917
Internal Events Maximum Averted Cost-Risk	=	$3,271,711

This total represents the monetary equivalent of the risk that could be eliminated if all on-line internal events based events could be eliminated for TMI-1.

E.4.6.2 EXTERNAL FLOODING EVENTS MAXIMUM AVERTED COST-RISK

The same process used to calculate the maximum averted cost-risk for the internal events contributors is used to calculate the maximum averted cost-risk for the external flooding contributors. The external flooding CDF, dose-risk, and economic cost risk estimates are used as input to the equations presented in Sections E.4.1 through E.4.5. As documented in Section E.2.3.1, the total external flooding CDF is 8.11E-05 when the contributions from all of the flood regimes are summed:

- External floods over 310' msl,
- External floods between 305' msl and 310' msl, and
- External floods below 305' msl

The total dose-risk and economic cost-risk for these flood regimes are 177.16 person-rem and $542,159, respectively, as documented in Section E.3.8.

The results of the external flood MACR calculations are provided below:

Maximum External Flooding Cost-Risk

Off-site exposure cost-risk	=	$5,328,835
Off-site economic cost-risk	=	$8,153,861
On-site exposure cost-risk	=	$50,177
On-site cleanup cost-risk	=	$1,579,915
Replacement Power cost-risk	=	$430,685
External Flooding Maximum Averted Cost-Risk	=	$15,543,473

E.4.6.3 NON-FLOODING EXTERNAL EVENTS MAXIMUM AVERTED COST-RISK

Finally, the maximum averted cost-risk for external events (excluding external flooding) must be estimated; however, this cost-risk must be estimated based on information in the IPEEE given that current, quantifiable external events models are not available. As described in Sections E.5.1.5 and E.5.1.6, these models have not been updated to reflect recent plant changes or current PRA techniques. Therefore, the absolute CDF values included in the IPEEE are generally not considered to be directly comparable to the results of the internal events PRA model.

The method chosen to account for non-flooding external events in the SAMA analysis is to use a multiplier on the internal events results. In previous SAMA analyses, it has been assumed that the risk posed by external events and internal events is approximately equal. This assumption is not unreasonable unless available analyses indicate that there are external events contributors that present an exceptionally high risk to the site. For TMI-1, external flooding scenarios are considered to present such a risk and are treated separately due to the potentially high frequency of severe flooding events.

The relative contributions of the remaining initiators are summarized in the following table:

IPEEE Contributor Summary (No External Flooding)

External Event	CDF
Seismic (LLNL seismic hazard curves)	8.43E-05
Fire	2.16E-05
High Winds	7.77E-07
Aircraft Impact	3.95E-07
Hazardous Chemicals	1.60E-07
Total	1.07E-04

While the CDF total of 1.07E-04 is about a factor of 3 greater than the internal events contribution, a large portion of the CDF is related to seismic risk. The large seismic CDF could be viewed as an indicator that earthquakes, like external floods, may represent an exceptionally high risk to TMI-1. However, as described in Section E.5.1.6.2.1, there are several specific issues related to the conservative nature of the seismic analysis that suggest seismic events are not a dominant contributor to the TMI-1 risk profile. As a result, seismic events are grouped with the remaining initiator types.

Similarly, the large external events CDF is not considered to be a basis for using a multiplier greater than 2 to account for external events risk due to the high seismic contribution. In fact, the use of unsupported, large multipliers for external events can be detrimental to the SAMA process:

- Over predicting the averted cost-risk of internal events based SAMAs through the use of an inflated multiplier could divert site resources to issues that are not important to the plant,
- Over predicting the averted cost-risk of an external events based SAMA could change the prioritization of addressing cost effective SAMAs away from important issues identified by the internal events model to highly uncertain issues identified by the external events analyses,
- Use of a larger multiplier impacts the MACR, which forces the identification of internal events based SAMAs that are not important to plant risk (refer to Sections E.5.1.1 and E.5.1.2) and consequentially reduces the credibility of the analysis.

For these reasons, a multiplier of 2 has been chosen to account for the TMI-1 external events contributions. This implies that the contribution to the MACR from the non-flooding external events is the same as the contribution from the internal events model ($3,271,711).

E.4.6.4 TMI-1 MAXIMUM AVERTED COST-RISK

As stated in Section E.4.6, the MACR is the total of these three components:

Internal Events	=	$3,271,711
External Events (excluding External Flooding)	=	$3,271,711
External Flooding	=	$15,543,473
Maximum Averted Cost-Risk	=	$22,086,895

The MACR is rounded to next highest thousand ($22,087,000) for SAMA calculations. It should be noted that the Phase II cost benefit calculations account for the difference between the rounded MACR and the actual MACR by adding the difference to the averted cost-risk calculated for each SAMA.

E.5 PHASE I SAMA ANALYSIS

The Phase I SAMA analysis, as discussed in Section E.1, includes the development of the initial SAMA list and a coarse screening process. This screening process eliminated those candidates that are not applicable to the plant's design or are too expensive to be cost beneficial even if the risk of on-line operations were completely eliminated. The following subsections provide additional details of the Phase I process.

E.5.1 SAMA IDENTIFICATION

The initial list of SAMA candidates for TMI-1 was developed from a combination of resources including:

- TMI-1 PRA results
- Industry Phase II SAMAs
- TMI-1 IPE (GPU 1993a)
- TMI-1 IPEEE (GPU 1994)

These resources are judged to provide a list of potential plant changes that are most likely to reduce risk in a cost-effective manner for TMI-1.

In addition to the "Industry Phase II SAMA" review identified above, an industry based SAMA list was used in a different way to aid in the development of the TMI-1 plant specific SAMA list. While the industry SAMA review cited above was used to identify SAMAs that might have been overlooked in the development of the TMI-1 SAMA list due to PRA modeling issues, a generic SAMA list was used as an idea source to identify the types of changes that could be used to address the areas of concern identified through the TMI-1 importance list review. For example, if long term DC power availability was determined to be an important issue for TMI-1, the industry list would be reviewed to determine if a plant enhancement had already been conceived that would address TMI-1's needs. If an appropriate SAMA was found to exist, it would be used in the TMI-1 list to address the DC power issue; otherwise, a new SAMA would be developed that would meet the site's needs. This generic list was compiled as part of the development of several industry SAMA analyses and has been provided in Addendum 1 for reference purposes.

E.5.1.1 LEVEL 1 TMI-1 IMPORTANCE LIST REVIEW

The TMI-1 PRA was used to generate a list of events sorted according to their risk reduction worth (RRW) values. The top events in this list are those events that would provide the greatest reduction in the TMI-1 CDF if the failure probability were set to zero. The events were reviewed down to the 1.010 level, which was chosen because it corresponds to the definition of a risk significant event, as defined in the PSA Applications Guide. [EPRI 1995]

An alternate method of establishing the lower review threshold would be to correlate the minimum expected SAMA implementation cost to an RRW value. For TMI-1, the minimum expected cost of implementation is believed to be a procedure change. The cost of procedure changes can vary depending on the type of procedure being modified and the scope of the changes, but a representative value is considered to be about $50,000, which is supported by previous industry cost estimates for procedure modifications [CPL 2004].

For TMI-1, the RRW value corresponding to $50,000 is about 1.008 (excluding External Flooding contributions). This can be demonstrated by reducing the CDF, dose-risk and off-site economic cost-risk by a factor of 1.008, which corresponds to an event with Level 1 and Level 2 based RRW values of just under 1.008. The corresponding internal events based averted cost-risk would be $25,966. Applying a factor of 2 to estimate the potential impact of external events (refer to Section E.4.6) results in a cost-risk of $51,932. This is approximately equal to the assumed minimum expected cost of implementation. While the RRW value of 1.008 is not exactly equal to the 1.010 established by the PSA Applications Guide definition of risk significance, the RRW threshold values are consistent and the use of 1.010 is considered to be adequate for this analysis.

The External Flooding contributions are excluded from the calculations establishing the RRW review threshold because the identification and quantification processes for External Flooding SAMAs are performed separate from the internal events model.

Table E.5-1 documents the disposition of each event in the Level 1 TMI-1 RRW list with RRW values of 1.010 or greater. Note that the review of each event involves a detailed evaluation of the cutsets including the event to identify the factors that make the event important.

E.5.1.2 LEVEL 2 TMI-1 IMPORTANCE LIST REVIEW

A similar review was performed on the importance listings from the Level 2 results. In this case, a composite importance file based on all release categories except RC9 was used to identify potential SAMAs. This method was chosen to prevent high frequency-low consequence events from dominating the importance listing. While RC9 contributes about 13 percent of the dose-risk, that small contribution depends on over 66 percent of the Level 2 frequency, which would heavily bias the importance list toward RC9 contributors.

The Level 2 RRW values were also reviewed down to the 1.010 level. As described for the Level 1 RRW list, events below the 1.010 threshold value are not “risk significant” and are not expected to yield cost beneficial SAMAs.

Table E.5-2 documents the disposition of each event in the Level 2 TMI-1 RRW list with RRW values greater than 1.010.

E.5.1.3 INDUSTRY SAMA ANALYSIS REVIEW

The SAMA identification process for TMI-1 is primarily based on the PRA importance listings, the IPE, and the IPEEE. In addition to these plant-specific sources, selected industry SAMA submittals were reviewed to identify any Phase II SAMAs that were determined to be potentially cost beneficial at other plants. These SAMAs were further analyzed and included in the TMI-1 SAMA list if they were considered to address potential risks not identified by the TMI-1 importance list review.

While many of the industry SAMAs reviewed are ultimately shown not to be cost beneficial, some are close contenders and a small number have been estimated to be cost beneficial at other plants. Use of the TMI-1 importance ranking should identify the types of changes that would most likely be cost beneficial for TMI-1, but review of selected industry Phase II SAMAs may capture potentially important changes not identified for TMI-1 due to PRA modeling differences or SAMAs that represent alternate methods of addressing risk. Given this potential, it was considered prudent to include a review of selected industry Phase II SAMAs in the TMI-1 SAMA identification process.

Phase II SAMAs from the following U.S. nuclear power sites have been reviewed:

- Turkey Point

- Arkansas Nuclear One, Unit 1
- Palisades
- D.C. Cook, Units 1 and 2
- Susquehanna Units 1 and 2
- Fitzpatrick

Four PWR and two boiling water reactor (BWR) sites were chosen from available documentation to serve as the Phase II SAMA sources. Few of the Phase II SAMAs from these sources were included in the initial TMI-1 SAMA list. Many of the industry Phase II SAMAs were already represented by other SAMAs in the TMI-1 list, were known not to impact important plant systems, or were judged not to have the potential to be close contenders for TMI-1. These SAMAs were not considered further. The following provides a summary of some of the issues considered during the review of the industry SAMAs.

E.5.1.3.1 Turkey Point

Turkey Point used a generic SAMA list as its starting point and few plant specific insights were available that might pertain specifically to B&W PWRs. In addition, only limited averted cost information was provided for the SAMAs and no changes were identified as cost beneficial, which made review of the list difficult. One SAMA had the potential to address a portion of TMI-1 risk in an inexpensive manner, but equipment limitations precluded its direct application to TMI-1:

- Turkey Point SAMA 111 – This SAMA suggests using Firewater as an alternate means of providing makeup to the steam generators. The prominent Level 1 cases involving loss of SG makeup flow at TMI-1 are SBO cases where the seals are in jeopardy. Providing alternate secondary side makeup without addressing the seal LOCA would not have a large impact on risk for TMI-1. In order for the use of Firewater to address important TMI-1 sequences, it would have to be capable of providing SG makeup early in the accident sequence and be combined with the installation of high temperature, damage resistant seals so that primary side inventory is not lost. Given that early SG makeup would require a pressure greater than the 130 psig available from the Fire Service Water system, this SAMA is not considered to be practical for TMI-1 and it is not included on the SAMA list. For Level

2, a large contributor to dose-risk is the failure to maintain water in the SGs to provide fission product scrubbing and for preventing induced tube rupture events. These events are considered to be best addressed by the addition of an independent auxiliary feedwater system, which is included as SAMA 22 based on the TMI-1 Level 2 importance list review.

E.5.1.3.2 ANO-1

While a generic SAMA list similar to the one used for Turkey Point was used in the ANO-1 SAMA submittal, one SAMA was found to be cost beneficial for ANO-1. This SAMA addresses the operator action to swap to recirculation mode, which was identified as an important contributor to TMI-1 risk:

- ANO-1 SAMA 129 suggests emphasizing a timely swap to recirculation mode in operator training and procedures. Theoretically, more emphasis could be placed on this well recognized issue for TMI-1, but in order to achieve a meaningful risk reduction based on training improvements, a specific deficiency would have to be identified in the TMI-1 training materials or procedures that could be rectified. No such deficiency has been identified based on the information available in the HRA. A SAMA has been proposed for TMI-1 to automate the swap to recirculation (SAMA 15), which would remove the operator from the primary role in the action. This is considered to be a more effective means of reducing the risk related to recirculation initiation failures for TMI-1. No additional SAMA related to improved training for swap to recirculation mode has been added to the TMI-1 SAMA list.

E.5.1.3.3 Palisades

Palisades identified several cost beneficial SAMAs; however, most of the changes were related to plant specific issues that are not applicable to TMI-1. Potential exceptions include adding the capability to operate EFW without power support and installation of a diesel motor to drive an EFW pump. These types of changes were shown to have a large impact on risk for Palisades and subsequent review of the plant design yielded the conclusion that the most effective means of addressing LOOP/SBO risk for the site was the installation of an additional EDG. For TMI-1 these three issues are dispositioned as follows:

- SAMA 2 addresses the use of a portable generator to allow extended EFW operation. It is combined with RCP seal upgrades as the important contributors including prolonged EFW operation are those in which seal integrity is challenged. This is considered to be the most appropriate means of addressing prolonged EFW operation for TMI-1 and no additional

SAMAs are suggested.

- Installation of a diesel engine to drive an EFW pump would improve the capability of TMI-1 to address SBO cases in which EFW has failed. Other industry investigations of this SAMA have concluded that connecting a diesel motor to an EFW pump would be easier/cheaper for a turbine driven pump than for a motor driven pump; however, for TMI-1, the initial TD EFW failure may preclude the use of the pump even with the diesel engine. For improved effectiveness in the important TMI-1 scenarios, the diesel engine should be connected to a motor driven EFW pump or a unique diesel driven pump should be used. In addition, this type of change needs to be accompanied by the installation of the high temperature, damage resistant seals to preclude the seal LOCA that will result from an SBO. Without securing primary side integrity, extended secondary side cooling would provide limited benefit. Finally, a portable generator would be required to power SG level instrumentation for effective level control. While TMI-1 SAMA 10 already addresses SBO cases with EFW failures, this diesel driven pump option provides an alternate approach to the issue and it has been included on the SAMA list for evaluation (SAMA 24).

- The addition of an EDG at Palisades as a result of the SAMA analysis would bring the total number of EDGs at the plant to three, which is equivalent to the current TMI-1 configuration. Some benefit could be gained through the installation of a fourth EDG for TMI-1, but common cause failures would limit the benefit and there are more cost effective changes that could be made to the existing EDG configuration that would greatly reduce risk (i.e., SAMA 1). Even with the inclusion of SAMAs 11 and 24 already on the SAMA list, a SAMA suggesting the addition of another EDG has been added to the TMI-1 SAMA list as an alternate means of reducing SBO risk (SAMA 25).

E.5.1.3.4 D.C. Cook

The D.C. Cook SAMA analysis showed that 5 different types of changes were determined to be cost beneficial. In three of the five areas, multiple SAMAs are identified as potentially cost beneficial and no single approach is identified as the most appropriate for D.C Cook. These risk areas were reviewed for TMI-1 and it was determined that the issues are already adequately addressed by the TMI-1 SAMA list or that the risk areas were not important contributors for the site:

- Minimize Consequences of RCP seal LOCAs: The TMI-1 SAMA list includes multiple

SAMAs addressing seal LOCA prevention, including the use of new seals (SAMA 2) and a means of providing an alternate heat sink for the thermal barrier cooling system (SAMA 7).

- Minimize Consequences of Loss of HVAC: TMI-1 does not require HVAC for successful operation of the plant during the 24 hour mission time considered in the PRA.

- Remove Dependence of Distributed Ignition System on AC Power: TMI-1 does not have igniters in the containment. A battery backed hydrogen ignition system could be added, which is included as SAMA 19 based on the TMI-1 Level 2 importance list review.

- Minimize Consequences of AC Bus Failures: AC cross-ties are proposed in the D.C. Cook SAMA analysis as a means of reducing the contribution of bus failures. It is not clear how a cross-tie would mitigate the bus failure cited in the analysis, but for TMI-1 bus failures are not large contributors to risk. The availability of the SBO EDG and its capability to be aligned to either division reduces the risk of these events.

- Improve Recovery from ISLOCA: For TMI-1, ISLOCA is dominated by DHR suction path failures after leak or rupture of valves DH-V-1 and DH-V-2. While the TMI-1 ISLOCA analysis does not take credit for any potentially mitigating actions, no actions that could reliably terminate the event are believed to be available. For example, 1) the isolation of DH-V-3 may not isolate the break or additional breaks may occur after isolation, 2) reduction of primary system pressure may reduce the flow out of the break, but it would not stop it, and 3) refill of the BWST does not place the plant in a stable state and the impacts of aux building flooding would have to be addressed. A SAMA was added to the TMI-1 list to extend the high pressure boundary in the DHR suction lines to include an additional isolation valve based on the TMI-1 Level 2 importance list review (SAMA 20).

E.5.1.3.5 Susquehanna

The Susquehanna SAMA analysis showed that five SAMAs were potentially cost beneficial when considered independently. When consideration was given to the overlapping benefits of the SAMAs and limits of the assessment process, only two were considered to be likely candidates for implementation. For TMI-1, it was determined that the issues are already adequately addressed by the TMI-1 SAMA list or that the risk areas were not important contributors for the site:

- SSES SAMAs 2a and 2b (4kV AC Cross-ties): The availability of the SBO EDG, which can be aligned to either division, serves a purpose similar to that of an AC cross-tie and minimizes the benefit of any cross-tie SAMAs. The existing cross-tie capability is not credited in the model.

- SSES SAMAs 5 and 6 (Additional/Auto Aligning Portable 480V AC Generators): The use of a portable 480V generator is suggested in TMI-1 SAMA 2 in combination with the installation of improved RCP seals. This change is considered to be the most appropriate for the TMI-1 design.

- SSES SAMA 3 (Staggered Depressurization): This is a 2 unit BWR issue that is not applicable to TMI-1.

No additional SAMAs have been added to the TMI-1 SAMA list based on a review of these SAMAs.

E.5.1.3.6 Fitzpatrick

The Fitzpatrick SAMA analysis identified two types of SAMAs as potentially cost beneficial. The SAMAs related to extending DC power availability are addressed by TMI-1 SAMA 2 and the SAMA related to providing alternate EDG HVAC is not applicable to TMI-1 as HVAC is not required for the 24 hour PRA mission time. No additional SAMAs have been added to the TMI-1 SAMA list based on a review of these SAMAs.

E.5.1.3.7 Industry SAMA identification Summary

The important issues for TMI-1 are considered to be addressed by the SAMAs developed through the PRA importance list review. Further, the plant changes suggested as part of that review were developed to meet the specific needs of the plant such that those SAMAs are more likely to provide effective means of risk reduction than SAMAs taken from other sites. However, effort was made to review other industry SAMA analyses to determine if other sites identified plant changes that could be cost beneficial for TMI-1. While it was found that other plants had developed SAMAs that addressed areas of concern for TMI-1, only two have been identified that could be adapted for inclusion in the TMI-1 SAMA list. While these SAMAs can be considered unique, the SAMAs only propose alternate means of addressing issues already targeted by other TMI-1 SAMAs:

- Install Damage Resistant, High Temperature RCP Seals with a Diesel Engine as an

Alternate Drive for an EFW Pump and Portable Generator for Level Control Instrumentation (SAMA 24).

- Install an Additional EDG (SAMA 25).

E.5.1.4 TMI-1 IPE

The TMI-1 IPE generated a list of risk-based insights and potential plant improvements. Typically, changes identified in the IPE process are implemented and closed out; however, there are some items that are not completed within the industry due to high projected costs or other criteria. Because the criteria for implementation of a SAMA may be different than what was used in the post-IPE decision-making process, these recommended improvements are re-examined in this analysis.

As a result of the IPE, five potential plant improvements were identified and considered for implementation at the plant. The following table summarizes the status of these plant improvements.

Description of Potential Enhancement	Status of Implementation	Disposition
Provide additional procedural guidance to direct operators to throttle low pressure injection prior to swapping the pump suction source from the BWST to the containment sump. Ensuring this step is taken will reduce the likelihood of incurring pump damage during the transition.	Implemented. Current procedures direct throttling of LPI flow after injection initiation as well as actions to mitigate pump cavitation in the event that the initial throttling steps do not preclude cavitation.	No further review required.
Enhance accident management guidelines for SGTR events to direct isolation of the failed OTSG and cooldown of the primary system using the intact OTSG. This is considered an effective means of mitigating SGTR scenarios.	Implemented. B&W Generic Emergency Operating Guidelines direct OTSG isolation on a number of signals, including high radiation and SG level, which are indicators of SGTR events. Cooldown of the reactor is also part of the generic guidance; therefore, the intent of this SAMA is met by the existing procedures.	No further review required.
For those SGTR cases in which isolation of the ruptured SG is not possible, inventory loss may continue through the ruptured OTSG. Updating the accident management guidelines to direct refill of the BWST to keep pace with the RCS inventory loss would help mitigate the evolution until other steps to stabilize the plant could be taken.	Implemented	No further review required.
Update the accident management guidelines to direct the operators to verify closure of the MU-14 valves after the transition to “piggyback recirculation mode” from high pressure injection mode. This would provide additional assurance that pathways to the BWST and the environment are isolated when this mode of recirculation is used.	Implemented	No further review required.

Description of Potential Enhancement	Status of Implementation	Disposition
Consider including the following operator actions in the Licensed Operator Requalification training Program: 1. Switchover to reactor sump recirculation following a LOCA 2. Refilling the BWST given SGTR 3. Properly throttling HPI flow after ES actuation 4. Holding open or reopening RCP seal injection valve MU-V-20 on loss of instrument air 5. Tripping RCPs before seal damage after loss of NSCCW 6. Taking actions to prevent boron concentration when in recirculation following a LOCA	Partial implementation: 1. The action to swap to recirculation following a LOCA is included in requalification training, most recently in year 2005. 2. No specific training has been identified for BWST refill in an SGTR. 3. The action to throttle HPI flow to prevent overcooling/overpressurization is included in requalification training, most recently in year 2006. 4. No specific training has been identified related to re-opening MU-V-20 on loss of IA. 5. The action to trip RCPs before seal damage on loss of NSCCW is included in requalification training, most recently in years 2005 and 2006. 6. The action to prevent boron concentration effects while in recirc mode after a LOCA is included in requalification training, most recently in year 2005.	The actions suggested for inclusion in the TMI-1 training program were based on the importance of the actions as evaluated in the IPE model. As the PRA is a living analysis, there is a potential for the importance of the operator actions to change based on the use of new failure data, inclusion of logic to reflect plant changes, application of improved modeling practices that remove conservatism, or elimination of errors. The importance list review performed for the SAMA analysis will identify the most important actions modeled in the current TMI-1 PRA. While no requalification training appears to be performed for items 2 or 4 from the list of actions suggested for inclusion in the requalification training by the IPE, the current PRA model does include these events: • BWST-HRE27-HTKOA: FAILURE TO REFILL BWST (SPLIT FRAC REV) (HRE27 in the IPE) • INHINJ4_MUHHVCOA: OPERATOR REOPENS MU-V20 (HINJ4 in the IPE) As a result, the SAMA process will address these actions, if necessary, and inclusion of a SAMA to add these actions to the requalification program independently from the importance list review is not required.

All of the plant changes proposed by the IPE have either been implemented or are addressed by the SAMA process. No SAMAs are included on the TMI-1 SAMA list to address IPE insights.

E.5.1.5 TMI-1 IPEEE

Similar to the IPE, any insights that were previously dispositioned based on non-SAMA criteria are re-examined as part of this analysis. In addition, any insights that are in the process of being addressed are examined as their resolutions could be important to the disposition of some SAMAs. The IPEEE was used to identify these items.

The following table summarizes the status of the potential plant enhancements resulting from the IPEEE processes and their treatment in the SAMA analysis. As can be seen, several unimplemented insights have been identified and included on the SAMA list:

Description of Potential Enhancement	Status of Implementation	Disposition
Install a flood safe means of providing 480V AC power and pumps to provide RCP seal cooling and makeup to the steam generators.	Implemented	While implemented, the design has been reviewed to determine if additional changes could be made to improve reliability. See Section E.5.1.6.4.
Load centers 1P, 1R, 1S, and 1T: add gusset weld reinforcements to improve seismic ruggedness.	Not implemented	Included as SAMA 27. See section E.5.1.6.2.2.
Install additional supports for the main control room ceiling to prevent failure in seismic events.	Implemented	No further review required.
Install a restraint on penetration pressurization tank PP-T-1A to prevent seismic interaction with reactor building purge inlet isolation valve AH-V-1D.	Implemented	No further review required.
Modify the diesel fire pump battery and fuel oil tank supports to increase their seismic ruggedness.	Not implemented	Included as SAMA 30. See section E.5.1.6.2.2.
Modify the anchorage for the decay heat service heat exchangers (DC-C-2A(B)) to improve their seismic ruggedness.	Not implemented	Included as SAMA 28. See section E.5.1.6.2.2.
Modify the anchorage for the EDG air receivers to improve their seismic ruggedness.	Implemented	No further review required.

An effort was also made to use the IPEEE to develop new SAMAs based on a review of the original results. However, the TMI-1 IPEEE was not maintained as a “living” analysis. This limits the capability of the models that make up the IPEEE as they do not include the latest PRA practices nor do they necessarily represent the current plant configuration or operating characteristics. The fact that the models are not currently in a quantifiable state presents further difficulty because the results are limited to what has been retained from the original analysis. These factors limit the qualitative insights and quantitative estimates that can be made with regard to external events contributors. On a larger scale, given that the industry has generally not pursued external events modeling at a level consistent with internal events models, the technology for external events analysis is not as robust or refined. The result is that the CDF values yielded by the internal and external events models are not necessarily comparable. External events models are considered to be useful tools for identifying important accident sequences and mitigating equipment, but the quantitative results should not be directly combined with those from the internal events models. In this analysis, external events contributions are estimated using a multiplier on the internal events results for the reasons described above. The exception is the treatment of external flooding.

Finally, it was necessary to review the changes to the site and surrounding area that were implemented after the completion of the IPEEE to determine if the changes could impact the conclusions of those analyses. The only changes identified with the potential to impact the conclusions of the IPEEE are the installation of the security towers and security fencing on the site grounds. In high wind events,

- Security towers may be sources for wind generated missiles, and
- Security fencing could blow into areas where they may prevent access to equipment required for mitigating actions.

The security towers are considered to be unlikely sources for wind generated missiles due to the fact that their design requires them to be able to withstand vehicle impact. With respect to the security fence issue, the only potentially important action identified that normally requires travel in areas where the fences could be an issue is the start of the SBO EDG. However, there is an access door to the SBO EDG building in the Unit 2 structure that could be used, if required. Finally, as described in Section E.5.1.6.3, the maximum averted cost risk for high wind related scenarios is well under the minimum expected cost of implementation of $50,000. This indicates that SAMAs that only impact high wind risk can not be cost beneficial. As a result, it has been concluded that plant changes subsequent to the completion of the IPEEE do not invalidate the docketed results.

E.5.1.6 USE OF EXTERNAL EVENTS IN THE TMI-1 SAMA IDENTIFICATION PROCESS

The IPEEE was used in the TMI-1 SAMA analysis primarily to identify the highest risk accident sequences and the potential means of reducing the risk posed by those sequences. The types of events considered in the TMI-1 external events analysis were identified by Supplement 4 of Generic Letter 88-20 (NRC 1991) and included:

- Internal Fires (Section E.5.1.6.1)
- Seismic Events (Section E.5.1.6.2)
- High Wind Events (Section E.5.1.6.3)
- External Flooding (Section E.5.1.6.4)
- Transportation and Nearby Facility Accidents (Section E.5.1.6.5)

Based on the TMI-1 review, no additional hazards were identified for analysis in the IPEEE.

The type of information available for the initiators that were evaluated by TMI-1 varied due to the manner in which they were addressed in the IPEEE. For instance, the fire analysis used an approach that combined the deterministic evaluation techniques from the EPRI Fire Induced Vulnerability Evaluation (FIVE) methodology with classical PRA techniques. The TMI-1 seismic analysis was performed using modified versions of the TMI IPE model to address seismic impacts on the plant's accident response capabilities. Core damage frequencies were also estimated for external flooding, high wind events, and transportation and nearby facility accidents. Due to limitations of the modeling processes, however, the results of these kinds of analyses are not necessarily compatible with those of the internal events analysis. As a result, each of the external event contributors must be considered in a manner suiting the type of analysis performed. A summary of the review process used to identify SAMAs is provided for each of the external event types listed above.

E.5.1.6.1 Internal Fires

As discussed above, the techniques used to model external events vary according to the type of initiator being analyzed. The TMI-1 Fire Model shares many of the same characteristics as the internal events model, but limitations on the state of technology produce results that are typically more conservative than the internal events model. The following summarizes the fire PRA topics where quantification of the CDF may introduce different levels of modeling uncertainty than the internal events PRA.

In general, fire PRAs are useful tools to identify design or procedural items that could be clear areas of focus for improving the safety of the plant. Fire PRAs use a structure and quantification technique similar to that used in the internal events PRA. Since less attention historically has been paid to fire PRAs, conservative modeling is common in a number of areas of the fire analysis to provide a “bounding” methodology for fires. This concept is contrary to the base internal events PRA, which has had more analytical development and is judged to be closer to a realistic assessment (i.e., best estimate) of the plant. There are a number of fire PRA topics involving technical inputs, data, and modeling that prevent the effective comparison of the CDF between the internal events PRA and the fire PRA. These areas are identified as follows:

PRA Topic	Comment
Initiating Events:	The frequency of fires and their severity are generally conservatively overestimated. A revised NRC fire events database indicates the trend toward lower frequency and less severe fires. This trend reflects the improved housekeeping, reduction in transient fire hazards, and other improved fire protection (FP) steps at plants.
System Response:	FP measures such as sprinklers, CO_2, and fire brigades may be given minimal (conservative) credit in their ability to limit the spread of a fire.
Sequences:	Sequences may subsume a number of fire scenarios to reduce the analytic burden. The subsuming of initiators and sequences is done to envelope those sequences included. This results in additional conservatism.
Fire Modeling:	Fire damage and fire spread are conservatively characterized. Fire modeling presents bounding approaches regarding the immediate effects of a fire (e.g., all cables in a tray are always failed for a cable tray fire) and fire propagation.
HRA:	There is little industry experience with crew actions under conditions of the types of fires modeled in fire PRAs. This has led to conservative characterization of crew actions in fire PRAs. Because the CDF is strongly correlated with crew actions, this conservatism has a profound effect on the calculated fire PRA results.
Level of Detail:	The fire PRAs may have reduced level of detail in the mitigation of the initiating event and consequential system damage.
Quality of Model:	The peer review process for fire PRAs is not as developed as internal events PRAs. For example, no industry standard, such as NEI 00-02, existed for the structured peer review of a fire PRA. This may result in less assurance of the realism of the model.

In addition to modeling limitations, the fire PRA may be subject to more modeling uncertainty than the internal events PRA evaluations. While the fire PRA is generally self-consistent within its calculational framework, the fire PRA does not compare well with internal events PRAs because of the number of conservative assumptions that have been included in the fire PRA process. Therefore, the use of the fire PRA results as a reflection of CDF may be inappropriate. Any use of fire PRA results and insights should consider areas where the “state of the art” in fire PRAs is less evolved than other PRA topics.

While the ability to directly compare the results of the internal events and fire models is limited, information is available that may be used to identify the most important contributors for TMI-1. The IPEEE provides some information related to equipment failures by fire scenario. This information has been summarized in the table below for the five fire scenarios that were not screened on low CDF.

Fire Area/ Scenario	Description	CDF	Major Equipment Failed
CB-FA-2d	East Inverter Room	4.94E-06/yr	Vital instrument bus ATA, battery chargers 1A and 1C, inverters 1A, 1C, and 1E, and control cables for 4.16kV AC emergency bus 1D.
CB-FA-2e	West Inverter Room	5.81E-06/yr	Battery chargers 1B and 1D, inverters 1B and 1D, and control cables for 4.16kV AC emergency bus 1E.
CB-FA-3a	1D Switchgear Room	3.94E-06/yr	4.16kV AC emergency bus 1D.
CB-FA-3b	1E Switchgear Room	4.96E-06/yr	4.16kV AC emergency bus 1E.
CB-FA-4b	Control Room – Console CR	1.96E-06/yr	• RCS inventory control and injection: makeup pumps MU-P-1B, MU-P-1C, and injection valves MU-V-16C, D • Nuclear Service River Water Pumps NR-P-1B, C • Nuclear Services Closed Cycle Cooling Water Pumps NS-P-1B, C • RCP seal injection and cooling: ICCW pumps, NR-V-10A, and B, NR-V-15A and B • Train B of DHR, DR, and DCCW, including DH-V-4B, 5B, 6B, and 7B. • ESAS manual actuation for train B • Operation of Containment spray and fans • Essential AC power: EDG 1A controls, EDG 1B controls, SBO DG controls, 1D 4.16kV AC bus controls, 1E 4.16kV AC bus controls.

Since the fire IPEEE is based on a progressive screening methodology, the CDF values for the fire areas presented above should not be arbitrarily added. Due to the differing levels of detail required to screen the various areas from further consideration, there can be significant conservative assumptions implicit in some of the final values, whereas some of these conservative assumptions may have been relaxed for more detailed analysis. Given this perspective, the CDF for these fire areas could be estimated as 2.16E-05/yr. The table above demonstrates that the CDF is distributed more or less evenly among the non-screened fire scenarios and that there are no dominant scenarios that contribute nearly all of the fire risk. In addition, while fires in each of these areas may impact a wide range of equipment, damage is typically limited to a single division. As a result, redundant equipment is often available to mitigate the fire events. Further discussion is provided for each of the fire area/scenarios below.

E.5.1.6.1.1 CB-FA-2d: East Inverter Room

Fires in the East Inverter room essentially fail the "A" division of AC and DC power. Random failures of specific "B" train equipment in conjunction with the fire event result core damage. Providing a means of maintaining primary side integrity and secondary side cooling without electric support is a potential means of reducing the risk of these fire scenarios.

Given that two portable 480V AC generators are already available at TMI-1, one to support the severe flooding guidelines and one for general plant use, the TMI-1 turbine driven EFW pump would be capable of providing secondary side cooling for extended periods without 4.16kV AC power if one of the 480V AC generators was used to power one of the 125V DC battery chargers (for level instrumentation/valve and pump control). Installation of the forthcoming Westinghouse type high temperature, damage resistant seals would virtually prevent seal LOCAs and maintain primary side inventory for extended periods (SAMA 2). Providing power to a 125V DC battery charger is considered to be required because the 125V DC system supports the vital 120V AC power supply for the OTSG level indicators. No credit is taken for operation of the TD EFW pump without level indication.

Some of the risk from fires in this room was identified in the IPEEE as resulting from damage to cables that run over ignition sources. Early insights from the work being performed for the TMI-1 fire model update indicate that there are no cables over ignition sources in this area that would be problematic. As a result, no SAMA is suggested to re-route or wrap the cables in this area; however, the core damage frequency for this room is conservatively not reduced to reflect this insight.

E.5.1.6.1.2 CB-FA-2e: West Inverter Room

Fires in CB-FA-2e are similar to fires in CB-FA-2d. A fire in the West Inverter room essentially fails the "B" division of AC and DC power. Random failures of the "A" train equipment typically result in loss of the corresponding systems and core damage will ensue. Providing a means of maintaining primary side integrity and secondary side cooling without electric support is a potential means of reducing the risk of these fire scenarios.

Given that two portable 480V AC generators are already available at TMI-1, one to support the severe flooding guidelines and one for general plant use, the TMI-1 turbine driven EFW pump would be capable of providing secondary side cooling for extended periods without 4.16kV AC power if one of the 480V AC generators was used to power one of the 125V DC battery chargers (for level instrumentation/valve and pump control). Installation of the forthcoming Westinghouse type high temperature, damage resistant seals would virtually prevent seal LOCAs and maintain primary side inventory for extended periods (SAMA 2). Providing power to a 125V DC battery charger is considered to be required because the 125V DC system supports the vital 120V AC power supply for the OTSG level indicators. No credit is taken for operation of the TD EFW pump without level indication.

Some of the risk from fires in this room is from damage to cables that run over ignition sources. If the cable trays were re-routed away from the electrical equipment that they currently overpass or if the cables were wrapped with fireproof material, the consequences of fires in the inverter room equipment could be reduced (SAMA 26).

E.5.1.6.1.3 CB-FA-3a and CB-FA-3b: 1D and 1E Switchgear Rooms

The only critical equipment located in these areas is the switchgear itself. Due to the layout of the switchgear, with main distribution buswork running through each major cubicle, a fire in virtually any cubicle could short the main buses to ground, disabling the entire train of switchgear. Even if the main buses are not failed, the fire brigade may require the bus to be de-energized to allow fire suppression.

It may theoretically be possible to improve the response of the fire brigade or provide some automated fire mitigation system to prevent the spread of the initiating fire; however, the fire would cause some damage to the switchgear before the mitigating actions could be initiated and the extinguishing method itself could cause additional damage to the switchgear. Due to the uncertainty related to potential switchgear damage, mitigating the effects of a fire in this area is considered to be a more appropriate means of addressing the fire risk than attempting to mitigate the fire itself. Given that two portable 480V AC generators are already available at TMI-1, one to support the severe flooding guidelines and one for general plant use, the TMI-1 turbine driven EFW pump would be capable of providing secondary side cooling for extended periods without 4.16kV AC power if one of the 480V AC generators was used to power one of the 125V DC battery chargers (for level instrumentation/valve and pump control). Installation of the forthcoming Westinghouse type high temperature, damage resistant seals would virtually prevent seal LOCAs and maintain primary side inventory for extended periods (SAMA 2). Providing power to a 125V DC battery charger is considered to be required because the 125V DC system supports the vital 120V AC power supply for the OTSG level indicators. No credit is taken for operation of the TD EFW pump without level indication.

E.5.1.6.1.4 CB-FA-4b: Control Room, Console CR

A main control room fire in console CR results in the loss of a variety of equipment and will likely force evacuation of the area to the remote shutdown panel (RSP). The RSP contains only a subset of the controls found in the main control room that were determined to be required to control the plant assuming that all of the equipment on the panel is available. In the case of a Console CR fire, some of this critical equipment is considered to be failed as a result of the fire, including NSRW pump NR-P-1C, NSCCW pump NS-P-1C, and train “B” of DHR/DR. Consequently, the RSP does not provide an adequate means of controlling the reactor in these scenarios.

A potential means of addressing this issue would be to expand the RSP to include both trains of the safe shutdown equipment. However, this option creates an area where a single fire could disable both trains of safety equipment. For this reason, enhancing the RSP in this way is not suggested.

Other SAMAs could be developed to address risk in this area, but given that the main control room is always manned and that no credit was taken for manual detection of a fire, the contribution from this fire area is considered to be overestimated and no SAMAs are believed to be required for main control room fires. Even if main control room fires could only be detected and extinguished 90 percent of the time, taking this credit in the IPEEE would have reduced the contribution of main control room fires to 1.96E-7, which would have been below the screening criteria for retention.

E.5.1.6.1.5 Fire SAMA Identification Summary

Based on the review of the TMI-1 fire area results, two SAMAs have been identified as potentially cost beneficial methods of reducing fire risk:

- Install Damage Resistant, High Temperature RCP Seals with a Portable 480V Generator for Extended EFW Operation (SAMA 2),
- Re-route Cables in Inverter Rooms (SAMA 26),

Any SAMAs that improve the plant response to an accident have the potential for reducing fire risk through the same mechanisms; however, these SAMAs are also considered to explicitly address the fire scenarios identified above. While SAMA 2 has been identified as potential means of reducing fire risk, it was also identified based on the internal events importance list and is not unique to the fire review.

E.5.1.6.2 Seismic Events

In response to Generic Letter 88-20, Supplement 4 (NRC 1991), TMI-1 prepared a seismic PRA (SPRA) to asses seismic risk at the site. The SPRA considered site specific seismic event frequencies in conjunction with the plant specific response to quantify a CDF using a modified version of the IPE risk model. The baseline case was developed using seismic event frequencies developed by EPRI (EPRI 1989), but also quantified risk based on the frequencies estimated by Lawrence Livermore National Labs (NRC 1994). The results from the Lawrence Livermore National Lab (LLNL) sensitivity are assumed to be the baseline results for the purposes of the SAMA analysis.

E.5.1.6.2.1 Seismic Modeling Overview

As with the Fire model, the TMI-1 seismic model was not maintained as a living model. As a result, the state of knowledge, use of current PRA techniques, and subsequent plant changes are not reflected in the SPRA results. However, the development of a full SPRA likely provided a more thorough evaluation of seismic risk than a seismic margins analysis, which many plants in the industry used for the IPEEE. The following steps summarize the seismic modeling process used for TMI-1:

1. **Determination of site specific seismicity characteristic**. This step involves the development of the frequencies of occurrence and magnitude of seismic events for the TMI site. Site structure analysis is also performed. The resulting frequencies and magnitudes of seismic events are the initiating events for the SPRA. Site structure responses are input into Step 5 where the capacities of the components which impact risk are calculated.

5. **Identification of those components important to plant safety**, including equipment, structures and procedures. The Level 1 PRA developed for TMI-1 is utilized to

determine those components which impact risk. Other studies such as the TMI Environmental and External Hazards Report and the USI A-46 Safe Shutdown Equipment List are used to ensure that the list of components which impact risk is comprehensive.

6. **An initial plant walkdown** of the identified systems and components is performed. Any plant seismic system interactions and unique plant features which may impact risk are identified.

7. **Develop plant logic models.** The plant logic models are developed using the Level 1 TMI-1 PRA with the addition of the failure rates (fragilities) of components due to seismically initiated events. A "pre-tree" approach is utilized to ensure that independent as well as seismic failures are accounted for in the logic model.

8. **A second plant walkdown** is performed to verify plant seismic response models and to collect data to determine component capacities.

9. **Analyze the plant seismic response models** to determine seismic initiated accident sequences and their frequency. This step involves the assembly and quantification of the plant logic models as well as the reporting and analyzing of the results.

10. **Identify plant seismic vulnerabilities**. This step defines any site specific vulnerabilities which are discovered as a result of the performance of the study.

While the systematic process described above was used to identify and quantify seismic risk, SPRAs include major sources of uncertainty, as described in Aggregation of Quantitative Risk Assessment Results (EPRI 2005). The areas of uncertainty were summarized in that document as follows:

- <u>Hazard Curve</u>: The seismic hazard curve is developed using a combination of actual data and expert judgment. The actual data used to develop the seismic hazard curve is generally very sparse. The expert judgment is generated using expert elicitation process and includes technical experts in their subject matter fields. However, technical experts tend to be conservatively biased as a result of a desire to be conservative knowing the implications of the development of the seismic hazard curves is the design specifications for important safety systems. This conservatism is evidenced in the development of the distribution assigned to the hazard curve. With a larger distribution, the mean values of the frequency of occurrence increase.

- <u>Fragility Curves</u>: Fragility analysis performed in a typical seismic PRA is based on the "weak link" method. In this method, a seismic capacity engineer determines the weak link associated with a system or a particular function of a system, structure or component and develops a fragility of the component based on seismic acceleration. Similar to the development of a hazard curve, a combination of actual experience, testing, analysis, and expert judgment (to a lesser degree) is used to develop the fragility. The determination of the weak link is based on the subjective judgment of the seismic capacity engineer as is the final fragility albeit to a lesser degree.

- Correlation of seismic failures: Typical seismic PRA assume that systems, structures and components (SSC) that are similar are assigned a 100 percent failure correlation in the model. That is, one fragility applies to the failure of all similar components. For example, if a high pressure ECCS pump fails during a given seismic acceleration, then all similar ECCS pumps also fail. However, it is more likely that these components are not 100 percent correlated and that subtle, and sometimes not so subtle, differences between the components and their respective anchorages provide significant margins between the failure accelerations.

- Treatment of offsite power: In a typical seismic PRA a loss of offsite power is assumed for seismic events of any significant magnitude. The probability of a seismically induced loss of offsite power event can vary significantly and considerable judgment is usually used in the development of the fragility of the offsite power grid. In addition, the loss of offsite power is typically a significant contributor to the results of the seismic PRA.

- Treatment of balance of plant equipment: In a typical seismic PRA, the balance of plant equipment is omitted from the analysis as an analysis simplification. The reduction in the scope of the seismic PRA by the elimination of balance of plant equipment is performed to reduce the resources required to develop the seismic PRA. Generally, the balance of plant equipment is not seismically designed and details of the design and anchorage of the equipment is difficult to obtain, which further complicates the development of fragilities. However, for some plant designs, specifically Boiling Water Reactors (BWRs), the balance of the plant systems provide significant mitigative potential. This is particularly true for the lower seismic accelerations where continued equipment operability is reasonably likely.

- Modeling simplifications: Other modeling simplifications are also employed to reduce the scope of the seismic analysis. These analysis simplifications are generally performed to reduce the scope of the fragility analysis which is resource intensive. These analysis simplifications include the treatment of human reliability analysis, support system operability/availability following a seismic event and others.

These characteristics of the SPRA limit the use of the absolute risk metrics that are a result of the analysis, but the relative rankings of the seismic contributors and the insights from the model are considered to be useful for identifying potential areas for plant improvements.

E.5.1.6.2.2 Seismic Contributor Review

For both the EPRI NP-6395-D and the NUREG-1488 seismic hazard curves, the largest CDF contributions came from the seismic events between 0.2g and 0.5g. The lower magnitude events (0.052g to 0.2g) had higher frequencies of occurrence, but the consequential damage to the plant systems was not severe and the conditional core damage probability was relatively low. The higher magnitude events (0.5g to 1.01g) caused heavy damage and resulted in high conditional core damage probabilities, but the frequencies of occurrence for seismic events of this magnitude were estimated to be low. The table below summarizes the Seismic CDF by initiating event category for both the EPRI and LLNL seismic hazard curves:

TMI-1 Seismic Results Summary

Initiating Event	Earthquake Range	Based on EPRI NP-6395-D		Based on NUREG-1488	
		CDF	Percent of Total CDF	CDF	Percent of Total CDF
SEIS1	0.052g to 0.2g	5.78E-06	18.0%	1.26E-05	14.9%
SEIS2	0.2g to 0.3g	1.04E-05	32.4%	2.61E-05	31.0%
SEIS3	0.3g to 0.5g	1.22E-05	38.0%	3.25E-05	38.6%
SEIS4	0.5g to 1.01g	3.71E-06	11.6%	1.31E-05	15.5%

As shown in the table above, the distribution of CDF among the initiating event categories remains consistent whether the EPRI or LLNL seismic hazard curves are used. The use of the LLNL seismic hazard curves amounts to a fairly linear increase in the CDF for each of the seismic initiating event categories without significantly changing the types of challenges that have the highest frequencies of occurrence. Because the absolute seismic CDF estimates are not directly used in the SAMA analysis, the choice of which seismic hazard curve is used to extract risk insights does not impact the SAMA analysis. Examination of the seismic component Fussell-Vesely values for the top contributors confirms this assertion:

Top Seismic Component Fussell-Vesely Contribution Summary

Component ID	Top Event	Fussell-Vesely Contribution (EPRI)	Fussell-Vesely Contribution (LLNL)	Description
FRAG15	GW	4.42E-01	4.00E-01	1P, 1S, 1R, 1T 480V Class 1E load centers seismic failure with offsite power available.
FRAG15	GY	1.57E-01	1.50E-01	1P, 1S, 1R, 1T 480V Class 1E load centers seismic failure with offsite power failure.
FRAG01	OX	1.21E-01	1.10E-01	Seismic offsite power insulator failure.
FRAG20	CX	7.34E-02	7.00E-02	Seismic control room ceiling failure.
FRAG09	GY	5.90E-02	6.00E-02	Seismic failure of EDG air start receivers.
FRAG11	RX	2.05E-02	2.00E-02	Seismic failure of DHCCW heat exchangers.
FRAG17	GY	1.07E-02	1.00E-02	Seismic failure of EDG ground resistors.

A review of the LLNL based results shows that the largest Fussell-Vesely value for a non-seismic failure is Riskman top event “GA” (Class 1E AC power train “A”) at 7.33 E-03, which implies that seismically induced failures are the main contributors to the seismic risk profile. As a result, the focus of the seismic review is based on the seismically induced failures rather than the independent failures. A review of each of the top seismic contributors is provided below.

<u>FRAG15</u>

This seismic component group includes 480V AC Class 1E load centers 1P, 1S, 1R, and 1T, which have been identified as components with low seismic ruggedness. As these load centers provide power to critical equipment and have HCLPF capacities slightly greater than the weaker off-site power related components, the availability of the load centers is important in both cases when off-site power is available and when it has failed. This is significant as seismic events that do not fail off-site power would not present a large threat to the site if the 480V AC load centers remained available. The low HCLPF values associated with these load centers demonstrate that the probability of a seismically induced failure of the equipment is not unlikely in earthquakes where off-site power remains available, which is problematic.

The IPEEE indicates that plant specific HCLPF values were estimated for these components types and were determined to be 0.12g. This implies that damage to these load centers may occur for even the SEIS1 initiating event group. One of the recommendations resulting from the IPEEE analysis was to reinforce the load center framework to prevent failure in seismic events; however, no work was done to strengthen the load center supports because the reduction in risk was considered to be low compared with the total CDF. Because these load centers are large contributors to the seismic risk profile and have not been strengthened since the IPEEE, reinforcing these 480V load centers has been added to the TMI-1 SAMA list (SAMA 27).

FRAG01

The ceramic insulators on the off-site power lines outside of the site and coming into the TMI-1 switchyard are susceptible to relatively low seismic shocks (HCLPF = 0.09). Other components, such as the auxiliary transformers and the 6.9kV AC distribution buses were also assessed to have the same low HCLPF capacity as the ceramic insulators. As a result, off-site power may be failed in many of the higher frequency, low magnitude earthquakes. The seismically induced LOOP requires the availability of the on-site AC systems to prevent core damage in the long term as recovery of off-site power is not credited in seismic events where widespread damage to the off-site AC distribution system could exist.

Improving the off-site AC distribution system is not considered to be feasible and it is not suggested as a SAMA. Even if a seismically rugged, dedicated line to another generating station could be established, no information is available related to how other generating stations would respond to seismic challenges and their availabilities can not be assured.

A more cost effective means of addressing the loss of off-site power cases would be to improve on-site AC power reliability. The issues related to improving the seismic capacities of plant components related to on-site AC power generation are discussed for FRAG20, FRAG09, and FRAG17 below.

Another potential means of addressing off-site AC power failures is to implement changes that would allow the plant to operate without 4.16kV AC power for extended periods of time. As described in Section E.5.1.6.1, installation of the Westinghouse type high temperature, damage resistant seals would maintain primary side integrity while providing power to a 125V DC battery charger would allow for long term operation of the TD EFW pump for secondary side heat removal (SAMA 2). Even though control of the TD EFW pump is possible, powering the batter chargers is considered to be required because the 125V DC system is supports the vital 120V AC power supply for the OTSG level indicators. No credit is taken for operation of the TD EFW pump without level indication.

FRAG20

Failure of the main control room ceiling is assumed to result in the loss of the “B” division of Class 1E AC power in the IPEEE. The consequences of the failure of the main control room ceiling are not highly predictable and may result in damage to other equipment, cause fires, injure plant operators, or on the other extreme, cause no damage at all. However, because these types of failures have the potential to impact important plant functions, supports were added to the main control room ceiling to reduce the likelihood of failure, as suggested in the IPEEE. The changes were accepted as adequate to address the identified issue and no additional changes are considered to be required to address control room ceiling failure.

FRAG09

The IPEEE identified a potential plant enhancement related to securing the EDG air start receivers to reduce the probability that they will fail after a seismic event. The changes were accepted as adequate to address the identified issue and no additional changes are considered to be required to address the EDG air start receiver anchorages.

FRAG11

The IPEEE identified a potential plant enhancement related to strengthening the anchorage used to secure the decay heat closed cooling water heat exchangers (DC-C-2A(B)) to reduce the probability that they will fail during a seismic event. This suggested change was reviewed, but not implemented as it was not considered to be a cost beneficial change.

Failure of the DHCCW heat exchangers results in the loss of the ability to remove decay heat from the RPV and would lead to core damage if the secondary side heat removal function were also disabled. Given the low HCLPF capacity estimated for these components (0.09g) and the high importance of the DHCCW system, the anchorage enhancements suggested in the IPEEE have been included on the TMI-1 SAMA list for evaluation (SAMA 28).

FRAG17

Failure of the EDG ground resistors results in failure of the EDGs, which will lead to core damage in the event that off-site power is not available. Given that the HCLPF capacity for these components was estimated at 0.25g compared with 0.09g capacities of off-site power components (such as the 1/A and 1/B distribution buses or the aux transformers), it is likely that core damage will ensue due to long term loss of power if the EDG ground resistors fail from seismic shock.

A potential means of addressing this issue would be to replace these components with a more seismically durable design (SAMA 29).

Diesel Fire Pump

The IPEEE includes a potential plant improvement that suggests enhancing the supports for the diesel driven fire pump fuel oil tanks and batteries. This insight was based on a walkdown of the fire suppression system that was performed as part of the seismic/fire interaction assessment (not for the SPRA model). No quantitative estimates of seismically induced fire risk were presented in the IPEEE, but the conclusion based on the plant review was that the risk was low. However, this modification was included in the IPEEE as a potential plant improvement given that the fuel tanks and battery racks appeared to have low seismic capacities and that the fire protection function could be degraded in a seismic event due to the weakness of the identified support structures.

The supports for fuel oil tanks and batteries could be improved, but the impact of implementing these changes would be difficult to determine given that the SPRA assumed that the fire protection system was failed. The available results do not provide any insights on how improving the fire protection system's availability could impact risk. Based on the information in the current PRA model documentation, it is known that the fire protection system supports operation of the following equipment:

- SBO EDG engine cooling
- Backup cooling for the DHCCW heat exchangers (not credited)
- Backup Instrument Air 1A and 1B compressor cooling

The SBO EDGs depend on the fire protection system as the primary engine cooling source. If the proposed fire protection system modifications were implemented, the fire protection system could be used to cool the SBO EDG in a seismic event. However, because of the similarity between the "1E" EDGs and the SBO EDG, the seismic model would assume SBO EDG failure in the same scenarios where the 1E EDGs fail. The only likely benefit would come from cases where random failures disable the other two EDGs, which are much smaller contributors than other, seismic based equipment failures.

The ability to provide backup cooling to the DHCCW system is of limited importance as the DHCCW heat exchangers, even with the improved anchorages, are the likely failure points of the system. In addition, the DHCCW system and the DHR system it supports depends on the availability of the AC distribution system, which may not be available.

The 1A and 1B Instrument Air (IA) compressors are normally cooled by SSCCW, but fire protection is available as an alternate means of cooling in the event that SSCCW is unavailable. As the SSCCW heat exchangers are identified as low capacity components, the SSCCW system would likely be unavailable in even the 0.052g to 0.2g initiating event category causing failure of the IA system. Some improvement in the Instrument Air system availability could be gained through improving the fire protection system's seismic durability.

While the Fussell-Vesely importance value for the IA system is low (0.01), improving the supports for the diesel fire pump fuel oil tank and the battery racks has been added to the SAMA list (SAMA 30) to address potential IA improvements, as identified in Section E.5.1.5.

E.5.1.6.2.3 Containment Performance Analysis

The effect of seismic events on the containment building performance was evaluated from two perspectives:

- Containment structure seismic capacity,
- Fragility of containment isolation valves and signals.

The containment structure analysis concluded that the lowest median acceleration capacity for the containment building was 11.0g and that the HCLPF was 3.5g. Based on the high seismic capacity of the containment structure, seismic failure was not considered to be a credible event and no further evaluation was performed. As a result, no SAMAs are considered to be required to address containment building failures.

The IPEEE analysis of the containment isolation function showed that most containment isolation valves would fail closed on loss of Instrument Air, which is a non-seismic designed system. As the lowest fragility of the containment isolation system was determined to be the

ESAS relays at 0.89g, Instrument Air is not expected to be available after seismic events that challenge the containment isolation system components. One issue was identified related to the potential seismic interaction between containment purge line isolation valve AH-V-1D and air supply tank PP-T-1A, which has a low seismic capacity. As a result of the IPEEE, the restraints for PP-T-1A were improved and failure of valve AH-V-1D due to contact with the tank was no longer considered to be an issue. No additional changes are suggested to address this issue.

The only other containment isolation issue of concern was for motor operated valves that would fail “as-is” on loss of the corresponding power supply. The IPEEE concluded that the recovery times for containment isolation failure allowed sufficient time for manual or automatic closure of the valves after the seismic event, prior to core damage. No changes were considered to be required to address any of these types of release pathways in the IPEEE.

While manual isolation is a proceduralized action at TMI-1 and is considered to be a credible recovery path for seismic scenarios, the containment penetration isolation valves were reviewed again for the SAMA analysis. In all cases where MOVs are used in containment isolation paths, it was determined that they are either on closed cooling system lines that would not provide a release path without additional failures, are on lines with diameters of one inch or less (not significant release paths), or are in series with AOVs and SOVs that would fail closed on loss of air/power.

The small containment penetrations (1 inch in diameter or less) do not provide a significant release pathway even if they are not isolated. These penetrations are screened from further review based on the small potential for release in conjunction with the ability to manually isolate the valves, if required.

The pathways that include MOVs in series with AOVs or SOVs that “fail closed” on loss of power/air are screened from consideration as the pathway would be isolated in loss of power cases that fail the MOVs. Manual action is also available to isolate the penetration in the event that the “in series” AOV or SOV fails to close.

Closed loop cooling systems could provide a release path through a “failed open” motor operated isolation valve; however, multiple boundary failures would be required in conjunction with core damage. For TMI-1, two closed loop cooling water system penetrations have been identified that include only MOVs as isolation valves:

- Nuclear Services Closed Cooling Water: Three MOVs, NS-V-4, NS-V-15, and NS-V-35, are used as isolation valves on an 8 inch line which penetrates the reactor building.

- Reactor Building Normal Cooling Water: Two MOVs, RB-V-2A and RB-V-7, are used as isolation valves on 8 inch cooling lines which carry water to and from the reactor building cooling units.

None of these penetrations are connected to the RCS and a release through either of these paths would require a pressurized containment atmosphere, a break in the reactor building side of the closed cooling water system boundary, and a break in the ex-reactor building side of the closed cooling water system boundary. These may be unlikely events, but no assessment of the probability of seismically induced failure of these pathways is available. The identified pathways could be isolated without operator actions if the valves were modified so that they fail in the “closed” position (SAMA 31). This SAMA is included the SAMA list, but it should be noted that changing the valves to “fail closed” introduces a failure mode for the valves that did not previously exist and may be detrimental in other accident scenarios.

E.5.1.6.2.4 Seismic SAMA Identification Summary

Based on the review of the TMI-1 seismic analysis, five Seismic related SAMAs have been identified:

- Install Damage Resistant, High Temperature RCP Seals with a Portable 480V Generator for Extended EFW Operation (SAMA 2),

- Improve the 480V AC load center welds (SAMA 27),

- Improve the DHCCW Heat Exchanger (DC-C-2A(B)) Anchorages (SAMA 28),

- Replace EDG Ground Resistors (SAMA 29).

- Improve Diesel Fire Pump Fuel Oil Tank and Battery Rack Supports (SAMA 30)

- Modify Specific Containment Penetration MOVs to “Fail Closed” (SAMA 31)

E.5.1.6.3 High Wind Events

The strategy taken to examine high wind risk in the TMI-1 IPEEE was to quantify the CDF due to high wind events and show that was below the screening frequency of 1.0E-06/yr. For the

IPEEE, initiating events with a CDF below the screening frequency were precluded from further analysis and no detailed review of the plant response for these types of events was required. For TMI-1, the high wind based CDF (sum of high wind damage and missile strikes) was estimated to be 7.77E-07/yr based on some simplifying assumptions, including:

- The exceedance frequency used for 400 mph winds was taken to be the exceedance frequency for the 318-380 windspeed range (5.0E-04). The 400 mph wind speed was used to determine the tornado strike frequency because it was assumed to be the wind speed at which damage to category 1 structures could occur. This was based on the design limit of 360 mph and consideration of material stress safety factors employed in the design process. As a result, the initiating event frequency may be overestimated,
- Any site tornado strike with wind speeds ≥ 400 mph is assumed to fail the BWST and CST and lead to core damage,
- Any tornado missile strike to outside equipment is assumed to fail the equipment.

No potential plant improvements related to high wind risk were identified in the IPEEE as the events were screened from detailed analysis based on low frequency of occurrence. For the purposes of the SAMA analysis, an estimate of the cost-risk corresponding to high winds can be used to determine if any cost beneficial changes could be identified for the site. The cost-risk corresponding to high wind events is determined using the following assumptions:

- Internal and external events risk are approximately equal (excluding external flooding),
- The external events CDFs are directly proportional to the cost-risk associated with a given external event.

For TMI-1, the internal events maximum averted cost-risk is $3,271,711, which implies that the non-external flood based external events contribution is also $3,271,711. For any given external event type, the corresponding cost-risk can then calculated by multiplying the total external event cost-risk by the ratio of the specific external event CDF to the total external events CDF (excluding external flooding). For example, for seismic events:

seismic cost-risk = total external events cost-risk * (seismic CDF / total external events CDF)

seismic cost-risk = $3,271,711 * (8.43E-05 / 1.07E-04) = $2,577,454

The following table summarizes the results for the non-flooding external events:

External Events Cost-Risk Summary

External Event	CDF	Ratio of CDF to Total External Event CDF	Corresponding Cost-Risk[3]
Seismic[1]	8.43E-05	7.88E-01	$2,577,454
Fire	2.16E-05	2.02E-01	$660,886
High Winds	7.77E-07	7.26E-03	$23,753
Aircraft Impact[2]	3.95E-07	3.69E-03	$12,073
Hazardous Chemicals	1.60E-07	1.50E-03	$4,908

1 Based on the NUREG-1488 seismic hazard curves.
2 Intentional aircraft impact is treated outside of SAMA and is not accounted for here due to the specific nature of the threat. The CDF quantified in the IPEEE is used to address the potential for accidental impact.
3 These cost-risks are calculated by multiplying the external events based cost-risk (see section E.4.6) by the percent contribution of the external event type.

The cost-risk associated with high winds is only $23,753, which is less than the minimum expected cost of implementation of $50,000 (see section E.5.1). As a result, it is unlikely that any cost-beneficial SAMAs could be found to reduce the risk of high wind events and no further review is considered to be required for the SAMA analysis.

E.5.1.6.4 External Flooding

As part of the TMI-1 IPEEE, the site was reviewed to identify the largest flooding risks. This included high river flows from dam breaks, hurricane effects, snow melt, and other non-hurricane events. The bounding risk was determined to be a flood of the Susquehanna River most likely caused by a hurricane event.

The external flooding analysis performed in the TMI-1 IPEEE divided flood risk into three categories:

- Floods with elevations greater than 310 feet mean sea level (msl)
- Floods with elevations between 305 and 310 feet msl,
- Floods with elevations less than 305 feet msl.

The main contributors to core damage for each of these flood elevation ranges are different and are examined separately for the SAMA analysis.

E.5.1.6.4.1 Floods Greater than 310 Feet msl

Given the configuration of the plant at the time of the IPEEE, floods with elevations over 310 feet msl were assumed to result in the loss of all electrical equipment due to flooding of site buildings. As the existing flood gates would not prevent flooding of these buildings for these scenarios, successful installation of the flood gates would increase the length of time available before building flooding, but not prevent core damage. Based on insights from the IPEEE and previous TMI-1 external flooding analyses, a strategy was implemented at the site to use a temporary power source and submersible pumps to maintain the reactor in a safe state during these extreme flood conditions. The CDF of 8.10E-05/yr that was reported in the IPEEE credited the use of this strategy.

As is the case with the other external events contributors, the level of development and uncertainty of the external flooding results is not comparable to the current internal events PRA. Assuming that external flooding risk dominates the risk profile for TMI-1 because the CDF is about two times greater than the internal events CDF is not necessarily correct. However, because there are no reliable means of demonstrating that floods exceeding 310 feet msl are low risk events and because the consequences of the events are severe, TMI-1 should have a reliable method in place to address these scenarios. Tangible work has already been completed at TMI-1 to satisfy this need, but the flood scenarios must be considered in the context of the SAMA analysis to determine if additional changes could be cost-beneficial.

Based on the evaluation presented in the TMI-1 IPEEE, the major contributors to the CDF for flood events over 310 feet msl include:

- Failure of secondary side cooling (7.03E-02) (represented only by operator error),
- Failure of primary side makeup and seal injection (4.22E-02) (represented only by operator error).
- Failure of the portable EDG in the 48 hour mission time (1.43E-01)

These contributors can be evaluated to identify areas of weakness and potential means of improving the associated reliabilities.

The guidance that was developed to mitigate floods greater than 310 feet msl as a result of the IPEEE is considered to provide an appropriate level of detail for the actions required in the relevant scenario. For the current configuration, no additional risk reduction is considered to be possible through procedural changes alone.

Flood risk could be reduced by improving the state of readiness of the corresponding equipment (prestaging, SAMA 32). Examples of the things that should be considered include:

- Permanently mount the power cables between the generator and pump staging areas,
- Permanently mount injection lines required for primary and secondary side makeup (may not be practical for the secondary side pump that takes suction from flood water in the turbine building),
- Consider an alternate secondary side suction source given that flood waters may recede well before an alternate secondary side makeup source will become available when AC power is re-established to the site,
- Ensure the power cables have all required connectors attached or stored in the staging areas,
- Pre-manufacture any required air supply or fuel oil connectors and store them in the staging areas,
- Stage the portable generator on the turbine deck or provide a means of hoisting the generator and fuel oil to the turbine deck when offsite power is not available,

Another area of interest is the reliability of the portable EDG. The operation of the portable diesel generator for the 48 hour mission time is a large contributor to failure that is based on data similar to what is used in the PRA. While it may be true that the failure rate for the portable generator is much less than a standard EDG, a lower failure rate cannot be justified without a verifiable data source. A potential means of improving the reliability of the temporary AC supply would be to procure a spare 480V AC generator.

An alternative to the pre-staging option would be to increase the flood height for which the unit is protected (SAMA 33). The current configuration protects to the design basis limit of 310 feet msl and levels any higher result in topping of the existing flood doors and flooding of sensitive areas. In order to decrease the flood CDF to about 1E-5/yr, the flood protection height would have to be increased to 324.5 feet msl on the following gates/structures (completely sealing doors is suggested, where possible):

EDG Building

- Gate D-1
- Gate D-3
- Gate D-4
- Air Vent Valves for the fuel oil day tanks
- Seal underground cable vaults to prevent short circuits due to water incursion

Air Intake Structure

- Access Door
- Air Intake Vents

Intermediate Building

- Gate C-1

Control Building

- Gate B-1
- Gate B-2

Intake Screen Pumphouse

- Gate E-1
- Gates E-2
- Gate E-3
- Gate E-4

By preventing the incursion of water, the existing safety equipment should be capable of maintaining safe shutdown conditions as long as fuel oil is available to the EDGs.

E.5.1.6.4.2 Floods with Elevations Between 305 and 310 Feet msl

Flood events with elevations between 305 and 310 feet msl were evaluated with an event tree in order to describe and quantify the various core damage scenarios initiated by such floods. Of the six core damage scenarios evaluated in the event tree, three scenarios contributed 94 percent of the risk:

- Sequence CD-A (36.8%): Flood frequency (305 to 310' msl) * probability off-site power is available * probability of failing to install flood gates (cold shutdown achieved) * probability of failing to implement severe flood cooling,

- Sequence CD-D (35.7%): Flood frequency (305 to 310' msl) * probability off-site power is unavailable * probability that cold shutdown is not achieved prior to flood (off-site power not available) * probability of failing to install flood gates (cold shutdown not achieved) * probability of failing to implement severe flood cooling,

- Sequence CD-E (21.4%): Flood frequency (305 to 310' msl) * probability off-site power is unavailable * probability of on-site power failure * probability of failing to implement severe flood cooling.

A common failure of sequences CD-A and CD-D is the inability to implement the severe flooding cooling strategy that was designed for floods over 310 feet msl. While this cooling strategy was intended to mitigate only the most severe floods, it can be used for any flooding events where Turbine Building flooding occurs given that the secondary side submersible pump uses the flood water in the Turbine Building as a suction source (the primary cooling pump suction source is the SFP and it is potentially available for any condition). For floods with elevations between 305 and 310 feet msl, damage to plant safety equipment requires failure of the flood gates. This requirement implies that the time available to implement the severe flooding cooling strategy is less than for the scenarios where flood elevations must rise to greater than 310 feet msl. As a result, the human error probability associated with this action is larger than for the scenarios with flood elevations over 310 feet msl. The IPEEE assumed an HEP of 5.0E-01 for implementing the severe flooding cooling alignment for the 305 to 310 foot msl floods. The improvements to the severe flooding mitigation strategy suggested for floods greater than 310 feet msl (SAMA 32) would also reduce the human error probability for sequences CD-A and CD-D and is considered to be an effective SAMA for these flood events.

Another common failure between sequences CD-A and CD-D is related to flood gate installation. The IPEEE assessment concluded that human error was the dominant factor related to flood gate installation failure and only human error was included in the failure probability. The HEPs for flood gate installation failure used in the IPEEE ranged from 5.6E-02 to 6.3E-02 based on the contemporary flood gate design. Since that evaluation, TMI-1 replaced the seal system on the Unit 1 class 1 buildings. The changes were considered to have improved seal reliability, made the seals easier to maintain, and made the seals/gates more convenient to use. These changes may have improved the reliability of flood gate installation in some way; however, the HEPs were not re-quantified to reflect the gate enhancements. Further changes to the gates could be made to improve their ease of use, such as replacing all gates with permanently installed swinging gates that could be secured with a handwheel. While such a change may make the flood gates easier to use, it would be difficult to justify a large difference in the HEP associated with the improved gate system and the current design given the long period of time that is available to properly install the gates. Based on an onsite review of the gates and discussions with the flooding engineer, no changes to the gates are suggested to improve their installation mechanisms.

Sequence CD-E appears to be a simplified evaluation of the cases in which both on-site and off-site AC power fail. From the information in the IPEEE submittal, the flooding event tree shows that core damage occurs for floods between 305 and 310 feet msl elevation if off-site power fails in conjunction with on-site AC power. However, the total CDF from the event tree is multiplied by the 0.5 failure probability for severe flooding cooling alignment to obtain the final CDF for floods with elevations between 305 feet msl and 310 feet msl. This implies that core damage does not occur before flood waters reach a level where the submersible pump could be used for secondary side cooling. No discussion is provided to describe the timing of off-site power loss relative to the flood height. This is important because the accident would evolve differently depending on whether it is caused by a hurricane or by flooding of the site transformers. For the case of a hurricane induced flood, offsite power could be lost early and on-site power would therefore be challenged at that time. An early failure in on-site power would result in core damage before flood water reaches the turbine building and no credit should be taken for the existing severe flooding cooling alignment. Quantitative resolution of this issue would require a more detailed analysis than what was performed for the IPEEE, but this uncertainty could be addressed through implementation the alternate secondary side suction source that is part of the SAMA 11 design. This provides a means of initiating both primary and secondary side makeup at any time during an accident.

A lower frequency sequence, CD-F, is based on the failure to provide an early flood warning to the plant. The early flood warning was assumed to be the cue instigating the initiation of the required flood procedures. While no credit was taken for installing the flood gates in time to prevent flooding of site buildings, the IPEEE credited implementation of the severe flooding cooling alignment. No discussion was identified that described why credit was taken for the severe flooding cooling alignment under this circumstance, but sequence CD-F would only comprise about 1 percent of the external flooding CDF if credit for the alignment were disallowed. Due to the low contribution of sequence CD-F relative to the other sequences, no SAMAs are considered to be required.

E.5.1.6.4.3 Floods with Elevations Below 305 Feet msl

In order for floods in this category to impact the site, the dike on the northern tip of the island is required to fail in conjunction with the flood event. The frequency of these events, which are required to cause site flooding, were determined to be less than 3 percent of the total flooding frequency alone. The conditional CDF given this type of flood event was estimated to be less than 0.1, which would correspond to a contribution of less than 0.3 percent of the total external flooding CDF.

No detailed CDF sequences were developed for these floods in the IPEEE and no specific failure contributions were identified other than dike failure. Improvements could be made to the dike, but even with dike failure, the buildings housing safety equipment would not flood. The only potential issue identified is the flooding of the EDG building cable vaults, which is addressed by SAMA 33. No other SAMAs are suggested to address this flood category.

E.5.1.6.4.4 External Flooding SAMA Identification Summary

Based on the review of the TMI-1 external flooding analysis, two external flooding related SAMAs have been identified:

- Prestage Severe Flooding Equipment (SAMA 32),
- Increase the Flood Protection Height (SAMA 33)

E.5.1.6.5 Transportation and Nearby Facility Accidents

Transportation and nearby facility accidents were included in the TMI-1 IPEEE to account for human errors or equipment failures that may occur in events not directly related to the power generation process at the plant. The types of hazards explicitly evaluated for the site include:

- Aircraft Impact
- Hazardous Chemical Release

E.5.1.6.5.1 Accidental Aircraft Impact

At the time the IPEEE was performed, available information related to military, commercial, and general aviation traffic was used to estimate the frequency of a release of radionuclides caused by aircraft impact. Given the information and conditions present at the time of the analysis, the frequency was determined to be 3.95E-07 per year and further analysis was not considered warranted.

It is recognized that the types of credible threats to nuclear facilities by aircraft have changed since the time the IPEEE was published. While this is true, efforts are underway within the industry to address this issue in conjunction with other forms of sabotage. Based on the fact that this topic is currently being analyzed in another forum and due to the complexity of the issue, intentional aircraft impact events are considered to be out of the scope of the SAMA analysis. The analysis performed in the IPEEE is used to provide insights related to accidental aircraft impact.

No potential plant improvements related to the risk of accidental aircraft impacts were identified in the IPEEE as the events were screened from detailed analysis based on low frequency of occurrence. For the purposes of the SAMA analysis, an estimate of the cost-risk corresponding to accidental aircraft impact can be used to determine if any cost beneficial changes could be identified for the site. The cost-risk corresponding to accidental aircraft impacts is determined using the following assumptions:

- Internal and external events risk are approximately equal (excluding external flooding),
- The external events CDFs are directly proportional to the cost-risk associated with a given external event.

For TMI-1, the internal events maximum averted cost-risk is $3,271,711, which implies that the non-external flood based external events contribution is also $3,271,711. For any given external event type, the corresponding cost-risk can then calculated by multiplying the total external event cost-risk by the ratio of the specific external event CDF to the total external events CDF (excluding external flooding). For example, for seismic events:

seismic cost-risk = total external events cost-risk * (seismic CDF / total external events CDF)

seismic cost-risk = $3,271,711 * (8.43E-05 / 1.07E-04) = $2,577,454

The following table summarizes the results for the non-flooding external events:

External Events Cost-Risk Summary

External Event	CDF	Ratio of CDF to Total External Event CDF	Corresponding Cost-Risk[3]
Seismic[1]	8.43E-05	7.88E-01	$2,577,454
Fire	2.16E-05	2.02E-01	$660,886
High Winds	7.77E-07	7.26E-03	$23,753
Aircraft Impact[2]	3.95E-07	3.69E-03	$12,073
Hazardous Chemicals	1.60E-07	1.50E-03	$4,908

1 Based on the NUREG-1488 seismic hazard curves.
2 Intentional aircraft impact is treated outside of SAMA and is not accounted for here due to the specific nature of the threat. The CDF quantified in the IPEEE is used to address the potential for accidental impact.
3 These cost-risks are calculated by multiplying the external events based cost-risk (see section E.4.6) by the percent contribution of the external event type.

The cost-risk associated with aircraft impact is only $12,073, which is less than the minimum expected cost of implementation of $50,000 (see section E.5.1). As a result, it is unlikely that any cost-beneficial SAMAs could be found to reduce the risk of accidental aircraft impact events.

It should be noted that the accidental aircraft impact assessment from the IPEEE was based on air traffic assumptions relevant to the initial license period. That assessment assumed a continuous “aircraft movement” growth for Harrisburg International Airport that was two to four times larger than the national average growth observed for the years 1979 to 1988. This resulted in an estimate of 177,000 aircraft movements per year for the midpoint of the original license period (1994). In order for the minimum cost SAMA (a procedure change of $50,000) to be potentially cost effective, the aircraft movement frequency would have to increase by a factor of 4.5. Even an order of magnitude increase in the aircraft movement would only yield a potential averted cost-risk of $120,730 for a completely effective SAMA. Based on the small impact of large changes in aircraft activity, any changes to aircraft movement frequency that may occur over the license renewal period are not expected to increase accidental aircraft impact risk to the point where potential SAMAs would become cost-effective. No SAMAs are suggested to address accidental aircraft impact for TMI-1.

E.5.1.6.5.2 Accidental Hazardous Chemical Release

Similar to the aircraft impact assessment performed for the IPEEE, the hazardous chemical release assessment was based on non-intentional events. Threats related to intentional chemical releases are credible; however, the specialized nature of security threats requires that they are treated in a separate forum and they are not addressed as part of the SAMA analysis.

For accidental releases, the IPEEE considered stationary and transient hazardous chemical sources that could pose a threat to TMI-1 if a release were to occur. As shown in the accidental aircraft impact discussion above, the cost-risk associated with hazardous chemical releases is only $4,908 assuming that the conditions present at the time of the IPEEE are applicable. Some variation may occur in the characteristics of the chemical loads near the site or transported on the rail lines close to the site over the course of the license renewal period. While it is not possible to accurately predict what these changes could be, an order of magnitude increase in the risk that was estimated in the IPEEE would only increase the associated cost-risk to $49,080. Given that an order of magnitude increase in the hazardous chemical release risk would still not be likely to yield any cost beneficial plant changes, no SAMAs are suggested to address these types of threats.

E.5.2 PHASE I SCREENING

The initial list of SAMA candidates is presented in Table E.5-3. The process used to develop the initial list is described in Section E.5.1.

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. The following screening criteria were used:

- Applicability to the Plant: If a proposed SAMA does not apply to the TMI-1 design, it is not retained.

- Implementation Cost Greater than Screening 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.

Table E.5-3 provides a description of how each SAMA was dispositioned in the Phase I analysis. All SAMAs that were found to be applicable to the TMI-1 design and to have a cost of implementation less than the MACR were passed to the Phase II analysis for a more detailed evaluation (Section E.6).

E.6 PHASE II SAMA ANALYSIS

Not all of the Phase II SAMA candidates require detailed analysis. The Phase II process allows for the screening of SAMAs known to be related to non-risk significant systems or to components/functions with low importance rankings. Due to the nature of the PRA based process used to develop the TMI-1 SAMA list, there are limited avenues for SAMAs of this type to be included in the list. However, potential pathways do exist:

- Inclusion of unresolved proposed plant changes from previous TMI-1 risk analyses,
- Inclusion of SAMAs based on the results of conservative modeling methods.

While no calculations are required for eliminating a SAMA that is linked to a non-risk significant system or components, some quantitative efforts are usually required to screen SAMAs that were developed to address risk contributors based on conservative modeling techniques. These cases are identified in Table E.5-4 and discussed in detail in the SAMA specific subsections of E.6.

For the SAMAs requiring detailed analysis, a more detailed conceptual design was prepared to allow the proposed SAMA to be modeled in the PRA. The results of the model changes were used in conjunction with the estimated implementation costs to evaluate whether or not the SAMA is cost beneficial.

The final cost based screening method is defined by the following equation:

Net Value = Averted cost-risk – cost of implementation

Where:

Averted cost-risk = (baseline maximum averted cost-risk – maximum averted cost-risk with SAMA implemented)

If the net value of the SAMA is negative, the cost of implementation is larger than the benefit associated with the SAMA and the SAMA is not considered beneficial. The baseline MACR was derived using the methodology presented in Section E.4. The MACR with the SAMA implemented is determined in the same manner with the exception that the PRA results used as input reflect implementation of the SAMA.

The calculation of the averted cost-risk for a SAMA must account for external events contributions. In some cases, representing the impact of a SAMA's impact on external events is complex. The method adopted in the SAMA analysis to address this issue is dependent on the type of SAMA to be quantified:

- For SAMAs that were not specifically developed to address external events issues, the multiplier defined in Section E.4.6.3 is used on the internal events averted cost-risk to provide an estimate of the non-external flooding external events benefit. This serves only as a gross approximation of the true benefit given that a SAMA may not impact both internal and external events risk in the same way. The external flooding model is quantified separately.

- For SAMAs that were specifically developed to address external events, the external events models are used to extract quantitative insights that can be used to provide bounding estimates of potential averted cost-risks. In these cases, the specific external events benefit calculations generally supercede the multiplier and the multiplier is not used. The details of the quantification process vary for each SAMA and are described in the SAMA specific discussions of Section E.6.

The implementation costs used in the Phase II analysis include both TMI-1 specific estimates developed by plant personnel and estimates taken from other SAMA submittals for those SAMAs that were determined to be highly similar. It should be noted that the TMI-1 specific implementation costs do not specifically include contingency costs for unforeseen difficulties nor do they account for any replacement power costs that may be incurred due to consequential shutdown time.

Sections E.6.1 – E.6.33 describe the detailed cost-benefit analysis that was used for each of the remaining candidates.

E.6.1 SAMA NUMBER 1: ENHANCE THE SBO EDG WITH AUTO START AND LOAD CAPABILITY

The availability of an auto start and load function for the SBO EDG will reduce the time required to restore power to the RCP seal cooling systems when the AC power has been lost and the "A" and "B" EDGs fail. Procedures should be reviewed to ensure that they will allow the operators to establish at least one form of seal cooling within 13 minutes of the initial loss of cooling. This is critical given that restoring RCP seal cooling after the 13 minute limit is considered to cause damage to the seals that will exacerbate seal leakage. The benefit of this SAMA would be enhanced if the auto start/load logic were capable of backing up either division of power for single EDG failures and selecting a single division to support in the event that both the “A” and “B” EDGs fail.

The SBO EDG is described in the plant manuals as being capable of accepting a load within 10 minutes of an SBO, but no credit is taken in the PRA for preventing seal damage due to the uncertainty in this performance time and the time required to ensure seal cooling is established. Some additional margin may be possible through procedure optimization, but the time window for action is so short that the most reliable way ensuring seal cooling is re-established before the 13 minute limit is reached is through automation of the start and load process for the SBO EDG.

E.6.1.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMA’s averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

In order to represent this SAMA in the PRA, it was necessary to perform both basic event data changes and event tree/fault tree structure modifications given that the LOOP-SBO event tree is structured to force a seal LOCA when the “A” and “B” EDGs are unavailable. Specifically, the operator action to start the SBO EDG was reduced by a factor of 10 to represent automation of the start function. Further, it was necessary to adjust the joint human error probabilities (JHEPs) that included the action to start the SBO EDG given that the manual start action is essentially eliminated by the SAMA. In this case, it is appropriate to eliminate all JHEPs associated with the SBO EDG start action as the automated start removes the human action from the dependence chain. With respect to the impact on seal LOCAs, the LOOP-SBO tree logic was changed to allow the SBO EDG to prevent a seal LOCA. The following table summarizes the model changes that were made:

SAMA 1 - Model Changes

Gate and / or Basic Event ID and Description	Description of Change
GSHEO1A----HDGOA: OPERATOR FAILS TO START SBO DG	The basic event probability was changed from 2.66E-02 to 2.66E-03.
JHHNSHOTHEOHEPOA: JHHNS10HOT1HEPOA AND GSHEO1A----HDGOA (dependence with tripping the RCPs)	The basic event probability was changed from 3.60E-05 to 0.0.
JHHNS10HEO1HEPOA: NRHNS10_HERHP1OA AND GSHEO1A----HDGOA (dependence with restarting NSRW pumps after a loop)	The basic event probability was changed from 3.10E-04 to 0.0.
LOOP-030 through LOOP-052	These gates were removed from the model as they are no longer required. The gates were previously used to model sequences in which a seal LOCA developed when only the SBO EDG was available.
RCP-LOOP-100	This gate was removed from the model as it was previously used to delineate cases where only the SBO EDG was available. These cases would previously result in seal LOCAs, but the SAMA implementation eliminates this condition.

It should be noted that the modeling strategy outlined above conservatively forces SAMA 1 to mitigate all seal LOCA cases with successful EFW operation when 4kV AC power has been lost to a single AC bus. There are scenarios in which core damage will occur for these conditions with SAMA 1 in place, but the impact is minor and would not change the conclusions for this SAMA. The results of the quantification are summarized below:

SAMA 1 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	1.88E-05	27.51	$98,718
Percent Change	-20.7%	-15.6%	-12.1%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 1 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.56E-07	1.59E-06	1.81E-07	1.27E-08	4.21E-11	4.21E-11	1.90E-10	2.40E-10	1.14E-08	1.24E-08	1.03E-09	2.88E-07	5.55E-07	1.34E-07	1.68E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.03	0.04	0.00	0.84	3.41	0.82	0.05
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$12,677	$44,202	$3,367	$236	$2	$2	$7	$9	$102	$111	$9	$2,589	$11,211	$2,707	$159

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.36E-10	2.08E-11	7.00E-08	6.41E-09	1.68E-07	2.58E-09	6.48E-07	9.53E-08	2.21E-06	1.07E-05	1.66E-08	1.63E-06	1.59E-08	1.88E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.20	0.02	0.23	0.00	0.87	0.13	4.91	2.85	0.00	0.44	0.00	27.51
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$2	$0	$662	$61	$642	$10	$2,475	$364	$13,879	$2,798	$4	$427	$4	$98,718

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 1 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$2,790,086	$481,625	2.0	$963,250

E.6.1.2 EXTERNAL FLOODING EVALUATION

This SAMA can have an impact on any scenario requiring the operation of the SBO EDG. For the external flooding cases, the three flood regimes are impacted differently:

- Floods over 310' msl: In these scenarios, the SBO EDG is flooded and this SAMA has no impact on the risk.

- Floods between 305' and 310' msl: Most of the sequences are not impacted by the enhanced capabilities of the SBO EDG as core damage is caused by failure of the flood gates (the SBO EDG is flooded) or because a flood warning is not provided and no preparations are made for the flood (the SBO EDG is flooded). Flood sequence "E" represents cases where the flood gates are correctly installed, but a loss of all AC power leads to core damage. Given that a loss of all power implies failure of the SBO EDG, SAMA 1 would provide no benefit to Sequence "E".

- Floods below 305' msl: The only impact these flood scenarios have on the plant is the potential to cause a loss of offsite power. While the inclement weather conditions that would likely exist in flood scenarios would provide an indication that a LOOP may occur, the operators would not start and prepare the SBO EDG for loading before the onset of loss of AC conditions. As a result, these scenarios are assumed to be impacted in the same way as the internal events LOOP events are.

In order to quantify the flooding benefits, it was necessary to characterize the impact of SAMA 1 on the internal events LOOP sequences. Once this is completed, the frequency of floods below 305' msl can be reduced by the same percentage.

Because SAMA 1 predominantly impacts LOOP events, the absolute reduction in LOOP CDF can be calculated by subtracting the CDF for SAMA 1 from the base CDF:

Absolute LOOP CDF Reduction = 2.37E-05 - 1.88E-05 = 4.90E-06

The total base LOOP CDF can be approximated by multiplying the Fussell-Vesely value of the LOOP initiating event (%AC) by the base CDF:

Base LOOP CDF = 3.26E-1 * 2.37E-05 = 7.72E-06

The percent reduction in the LOOP CDF can then easily be determined:

Percent Reduction in LOOP CDF = (Absolute LOOP CDF Reduction / Base LOOP CDF) * 100

Percent Reduction in LOOP CDF = (4.90E-06 / 7.72E-06) * 100 = 63.5%

Based on these results, the CDF for the floods below 305' msl was reduced by 63.5%.

The following tables summarize the results of these changes:

SAMA 1 - External Flooding Results

	CDF (/yr)	**Dose-Risk (person-rem/yr)**	**OECR ($/yr)**
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	8.09E-05	176.92	$541,385
Percent Change	-0.2%	-0.1%	-0.1%

A further breakdown of this information is provided below according to release category.

SAMA 1 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' Sequence A	305' to 310' Sequence B	305' to 310' Sequence C	305' to 310' Sequence D	305' to 310' Sequence E	305' to 310' Sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	9.13E-08	8.09E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.13	176.92
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$445	$541,385

Based on these results, the external flooding component of the averted cost-risk can then be calculated:

SAMA 1 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$15,520,578	$22,895

E.6.1.3 COST OF IMPLEMENTATION

The cost of this SAMA was estimated to be $3,125,000 (Exelon 2007c).

E.6.1.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 1 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$963,250	$22,895	$986,145	$3,125,000	-$2,138,855

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.2 SAMA NUMBER 2: INSTALL DAMAGE RESISTANT HIGH TEMPERATURE RCP SEALS WITH A PORTABLE 480V AC GENERATOR FOR EXTENDED EFW OPERATION

RCP seals have been developed that are capable of preventing seal LOCAs on loss of seal cooling events. The Flowserve N-9000 seals are reported to limit seal leakage to about 1 gpm per RCP seal even when cooling to the seals is completely lost, which is essentially considered to eliminate the seal LOCA evolution. In SBO cases, prevention of a seal LOCA will allow for extended operation if level instrumentation can be supplied using the vital 120V AC system. Powering the station battery chargers with a portable 480V AC generator would provide this capability and allow control of the TD EFW system to be retained in the MCR.

In order to maintain control of the TD EFW system from the MCR, power must be supplied for multiple loads, including:

- Level instrumentation,
- Control of EF-V-30 valves, and
- Instrument air for EF-V-30 valves.

The 480V AC generator should be capable of providing these loads as long as the correct connections are made and the loads are managed properly. Cooling water is another concern for the instrument air compressors, but IA-P-1A and IA-P-1B can be cooled from the Altitude Tank. Plant documentation indicates that this connection is linked to the Fire Service system, so it is also assumed that Fire Service water could be used in an SBO based on the availability of the diesel driven fire pump.

In the event that one of these support systems fails, it is also possible to operate the EF-V-30 valves locally, without any support other than power for SG level instrumentation.

E.6.2.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMA's averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

To simulate the installation of a new RCP seal package that prevents the onset of a RCP seal LOCA, a recovery event was appended to cutsets using QRECOVER32 that satisfied the gate logic for RCP-LOOP-100, "RCP SEAL FAILURE". This process captures all of the seal LOCAs contributors and multiplies them by the probability of the recovery event, which in this case was set to 1.0E-01. While the new seals may be capable of preventing a seal LOCA with a reliability greater than 90% when cooling is lost, the existing PRA model is not configured to analyze the probability of core damage after a seal LOCA is prevented. Ten percent of the original seal LOCA contribution is retained to represent:

- The CDF from cases where the new seals fail and a seal LOCA occurs,
- The CDF from cases where the new seals prevent a seal LOCA, but the core is damaged due to other failures.

In order to account for the reduction in CDF due to the availability of a spare 480V AC diesel generator to supply backup 480V AC power, the HEP event EFHEF1_OPERH2HOA was reduced by a factor of 10. The CDF reduction is primarily due to the improved performance shaping factors related to the ability of the operator to use the MCR controls for EFW, but there may also be some improvement in the HEP related to the reduced manipulation time for the action. In the TMI-1 model, the relevant operator actions include the independent event discussed above as well as joint human error events. In this case, allowing for continued control of EFW in the MCR would not eliminate the dependence with other actions as the mechanism of dependence is primarily cognitive, but it could impact the JHEP probabilities. Depending on the nature of the JHEP calculation, the actual impact on the JHEP probabilities could range from a percent or two all the way to a factor of 10. Rather than recalculate the JHEPs, they were conservatively eliminated for convenience. No HEP is included for failure to align the portable 480V AC generator. For this evaluation, it is assumed that the operators will always be able to align the charger before depletion of the batteries and that the generator will always run.

No model requantification was performed for this SAMA. All of these operations were performed on the existing base cutset files through basic event data changes and cutset recovery. The following table summarizes the changes that were made to the basic event data and a brief description of the recovery file used to modify the seal LOCA contributors:

SAMA 2 - Model Changes

Gate and / or Basic Event ID and Description	Description of Change
EFHEF1_OPERH2HOA: OPERATOR FAILS TO MANUALLY OPERATE EF-V-30 AFTER LOSS OF INSTRUMENT AIR	The basic event probability was changed from 2.00E-03 to 2.00E-04.
JHHEF1-HBW1HEPOA: EFHEF1_OPERH2HOA AND BWHBW1-----HP2OA (dependence between EF-V-30 operation and manual HPI initiation)	The basic event probability was changed from 1.00E-04 to 0.0.
JHHAM2-HEF1HEPOA: AMHAM2-----HC1OA AND EFHEF1_OPERH2HOA (dependence between EF-V-30 operation and manual start of air compressors after a LOOP)	The basic event probability was changed from 4.61E-03 to 0.0.
JHHAMHEFHBWHEPOA: JHHAM2-HEF1HEPOA AND BWHBW1-----HP2OA (dependence between EF-V-30 operation, manual start of air compressors after a LOOP, and manual initiation of HPI)	The basic event probability was changed from 2.40E-04 to 0.0.
JHHAM1-HEF1HEPOA: AMHAM1-----HC1OA AND EFHEF1_OPERH2HOA (dependence between EF-V-30 operation and failure to bypass IA dryer transfer valve)	The basic event probability was changed from 1.81E-02 to 0.0.
JHHAMHEFHB2HEPOA: JHHAM1-HEF1HEPOA AND BWHBW1-----HP2OA (dependence between EF-V-30 operation, failure to bypass IA dryer transfer valve, and manual initiation of HPI)	The basic event probability was changed from 4.90E-05 to 0.0.
RCP-SEAL-IMPROVE.CAF	New recovery fault tree with top gate “Recoveries” used to apply a recovery event (RCP-SEAL-IMPROVE) to all cutsets including seal LOCAs. The new gates include: • RECOVERIES (Equivalence gate connected to new gate RCP-SEAL-IMPROVE) • RCP-SEAL-IMPROVE (Equivalence gate connected to existing gate RCP-LOOP-100)

Note that the action EFHEF2_OPERHFCOA and its JHEPs are not included in the model changes tabulated above as they have no measurable impact on the CDF. The results of the quantification are summarized below:

SAMA 2 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	1.13E-05	15.24	$56,521
Percent Change	-53.3%	-53.3%	-49.7%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 2 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.18E-07	9.21E-07	1.80E-07	9.32E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	7.26E-09	1.25E-09	4.86E-11	2.76E-08	3.56E-07	4.98E-08	5.87E-09
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.39	5.27	0.91	0.05	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.08	2.19	0.31	0.02
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$11,620	$25,604	$3,348	$173	$0	$0	$0	$0	$65	$11	$0	$248	$7,191	$1,006	$55

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.43E-11	0.00E+00	6.57E-09	1.43E-09	6.77E-08	4.09E-10	7.20E-08	3.75E-08	6.73E-07	8.14E-06	5.45E-09	3.18E-07	8.19E-10	1.13E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.02	0.00	0.09	0.00	0.10	0.05	1.49	2.17	0.00	0.08	0.00	15.24
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$0	$0	$62	$14	$259	$2	$275	$143	$4,226	$2,133	$1	$83	$0	$56,521

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 2 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$1,595,737	$1,675,974	2.0	$3,351,948

E.6.2.2 EXTERNAL FLOODING EVALUATION

This SAMA can have an impact on any SBO scenario as well as any seal LOCA scenario. For the external flooding cases, the three flood regimes are impacted differently:

- Floods over 310’ msl: In these scenarios, all safety equipment is flooded and the EFW system would not be available. Installation of the damage resistant RCP seals, which is part of this SAMA, would preclude the need to align the primary side makeup/seal injection pump. This would reduce the operator workload slightly improve the reliability of the flood mitigation actions, but the existing HEP is considered to be representative of the difficult set of actions that remain to align secondary side cooling and no reduction of the extreme flood CDF is assumed to occur based on the installation of the N-9000 seals.

- Floods between 305’ and 310’ msl: Most of the sequences are not impacted by this SAMA as core damage is caused by failure of the flood gates (the SBO EDG is flooded) or because a flood warning is not provided and no preparations are made for the flood (the SBO EDG is flooded). Flood sequence “E” represents cases where the flood gates are correctly installed, but a loss of all AC power leads to core damage. These SBO cases are assumed to be completely mitigated by this SAMA

- Floods below 305’ mls: The only impact these flood scenarios have on the plant is the potential to cause a loss of offsite power. As a result, these flooding sequences would be impacted in the same way as the internal events LOOP events. In order to simplify the calculations, SAMA 2 is assumed to eliminate all risk from this flooding sequence. Given the low contribution of these sequences relative to the entire flooding contribution, the impact of this conservative assumption is minimal.

The following tables summarize the results of these changes:

SAMA 2 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	7.72E-05	166.08	$508,082
Percent Change	-4.8%	-6.3%	-6.3%

A further breakdown of this information is provided below according to release category.

SAMA 2 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' Sequence A	305' to 310' Sequence B	305' to 310' Sequence C	305' to 310' Sequence D	305' to 310' Sequence E	305' to 310' Sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	0.00E+00	8.65E-08	0.00E+00	7.72E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	132.75	13.13	0.19	1.89	17.87	0.00	0.25	0.00	166.08
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$405,951	$40,149	$598	$5,767	$54,839	$0	$778	$0	$508,082

Based on these results, the external flooding component of the averted cost-risk can then be calculated:

SAMA 2 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$14,598,420	$945,053

E.6.2.3 COST OF IMPLEMENTATION

The cost of this enhancement was estimated to be $7,300,000 by the TMI staff (Exelon 2007c).

E.6.2.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 2 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$3,351,948	$945,053	$4,297,001	$7,300,000	-$3,002,999

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.3 SAMA NUMBER 3: USE NSCCW AS AN ALTERNATE COOLING SOURCE FOR THE DHR HEAT EXCHANGERS (DH-C-1A/B)

For LOCAs requiring heat removal with the RHR system, DHRW and DHCCW failures are large contributors to loss of the primary cooling function. Providing the ability to cross-tie the NSCCW system to the DHR heat exchangers would diversify the plant's heat removal capability and eliminate the failures associated with loss of DHRW or DHCCW flow. The hard piped connections are assumed to be sized to allow enough flow to remove decay heat (not just pump cooling loads) and that each division is provided with a cross-connection to NSCCW.

E.6.3.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMA's averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

In order to represent this SAMA in the PRA, the NSCCW system was modeled to supply a backup cooling water source in the event that either of the DHCCW trains fails to provide cooling to the DHR heat exchangers. In the event that the DHCCW system is unavailable to provide cooling water on the shell side of either of the DHR heat exchangers, an operator action is required to restore cooling flow via cross-connecting the NSCCW header with the applicable DHR heat exchanger via a remotely operated MOV from within the MCR. The affected model logic was OR gate LPRG0007 for DHR heat exchanger train A and OR gate LPRG0019 for DHR train B. Specifically, the DHCCW train A system top event HA under gate LPRG0007 was replaced with a new AND gate named LPRG0007-1. The inputs to LPRG0007-1 are system top event HA and a new OR gate named NS-1A. The inputs to gate NS-1A are similar to the inputs under the nominal NSCCW system top event NS, with the addition of an MOV event for DHR heat exchanger DH-C-1A and an HEP event that represents operator failure to restore cooling water flow. Likewise, system top event HB under gate LPRG0019 was replaced with a new AND gate named LPRG0019-1. The inputs to LPRG0019-1 are system top event HB and a new OR gate named NS-1B. The inputs to gate NS-1B are similar to the inputs under the nominal NSCCW system top event NS, with the addition of an MOV event for DHR heat exchanger DH-C-1B and the same HEP event described above for restoration of cooling water flow.

In addition, all affected logic described above that is modeled within the logic structure for post-LOOP recovery scenarios was also modified, with gate names appended with the characters "-R".

The model changes identified above yielded a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk, as summarized below:

SAMA 3 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	2.01E-05	29.97	$105,253
Percent Change	-15.2%	-0.3%	-0.3%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 3 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.54E-07	1.52E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	4.34E-09	3.09E-07	7.28E-07	1.26E-07	2.20E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.60	8.69	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.01	0.91	4.48	0.77	0.06
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$12,621	$42,256	$3,367	$236	$3	$3	$7	$11	$351	$131	$39	$2,778	$14,706	$2,545	$208

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.21E-10	2.08E-11	7.97E-08	8.08E-09	2.24E-07	2.51E-09	7.38E-07	1.82E-07	2.78E-06	1.05E-05	1.69E-08	2.15E-06	1.78E-08	2.01E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.22	0.02	0.30	0.00	1.00	0.25	6.17	2.80	0.00	0.57	0.00	29.97
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$2	$0	$753	$76	$856	$10	$2,819	$695	$17,458	$2,748	$4	$563	$5	$105,253

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 3 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$2,995,414	$276,297	2.0	$552,594

E.6.3.2 EXTERNAL FLOODING EVALUATION

This SAMA has a very limited impact on external flooding scenarios. For the external flooding cases, the three flood regimes are impacted differently:

- Floods over 310’ msl: In these scenarios, flood waters fail the DHR system and the SAMA has zero impact.
- Floods between 305’ and 310’ msl: Most of the sequences are not impacted by the enhanced cooling capabilities of the DHR system as core damage is caused by failure of the flood gates (safety equipment flooded, SBO) or because a flood warning is not provided and no preparations are made for the flood (safety equipment flooded, SBO). Flood sequence “E” represents cases where the flood gates are correctly installed, but a loss of all AC power leads to core damage. These conditions will cause a seal LOCA and for the small fraction of the scenarios in which power is recovered, the cross-ties could be used to mitigate certain failures. The impact of this SAMA can be approximated by using the baseline internal events model to determine the percent contribution of the “power recovered” SBO sequences to the total SBO contribution. Then, if it is assumed that the relative distribution of “power recovered” sequences for the “E” flood sequence as the same as for the internal events model, the portion of the flood sequence “E” CDF impacted can be calculated. For this evaluation, it is assumed that implementation of this SAMA will eliminate all SBO “power recovered” risk and that the “power recovered” fraction is the same for flood events as it is for internal events SBOs (likely optimistic for the flood case).
- Floods below 305’ mls: The only impact these flood scenarios have on the plant is the potential to cause a loss of offsite power. For simplicity, the CDF for this sequence is assumed to be completely eliminated.

Based on the internal events model, SBO sequences contribute a CDF of 3.25E-06/yr while the power recovered SBO sequences contribute only 2.21E-08/yr. This indicates that the “power recovered" SBO evolutions contribute only 0.7 percent of the SBO CDF (2.21E-08 / 3.25E-06/yr * 100 = 0.7). For flood sequence "E", the expected CDF reduction would then be 2.56E-08 (7.0E-03 * 3.66E-06 = 2.56E-08).

The following tables summarize the results of quantification strategy:

SAMA 3 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	8.08E-05	176.71	$540,710
Percent Change	-0.3%	-0.3%	-0.3%

A further breakdown of this information is provided below according to release category.

SAMA 3 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' Sequence A	305' to 310' Sequence B	305' to 310' Sequence C	305' to 310' Sequence D	305' to 310' Sequence E	305' to 310' Sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.63E-06	8.65E-08	0	8.08E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.63	0.25	0.00	176.71
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,628	$778	$0	$540,710

Based on these results, the external flooding component of the averted cost-risk can then be calculated:

SAMA 3 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$15,501,141	$42,332

E.6.3.3 COST OF IMPLEMENTATION

The cost of this enhancement was estimated to be $2,450,000 by the TMI staff (Exelon 2007c).

E.6.3.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 3 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$552,594	$42,332	$594,926	$2,450,000	-$1,855,074

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.4 SAMA NUMBER 4: PROVIDE ALTERNATE POWER TO HPI PUMP MINIMUM FLOW RECIRCULATION VALVES MU-V-36 AND MU-V-37

The current PRA model logic correctly assumes isolation of HPI minimum flow recirculation valves MU-V-36 and 37 on an ESAS, but it does not include the AC power dependences for the "close" action. However, the logic related to opening the minimum flow valves does include the power dependencies, which can result in the generation of cutsets that include the failure to open a flow path that was never isolated. This is critical for the HPI pumps in cases where the HPI flow to the RCS is very low due to the small size of the RCS break/leak. Based on system review and discussions with plant personnel, the only events that could cause the MU-V-36 or MU-V-37 valves to be "stranded closed" are those in which an ESAS based closure occurs when power is available to one or both valves and then one or both of the divisions of valve power fails before the valve(s) can be re-opened to support HPI minimum flow recirculation.

A quantification of the contribution from scenarios of this type would require a dynamic PRA model, which is not available to TMI-1. However, an approximation can be performed to show that risk associated with the MU-V-36/37 design is low and that no SAMAs are required to modify the power supplies to the valves.

The current model assumes that power is always available to isolate MU-V-36/37 and if this assumption is accepted for this evaluation, a time weighted probability can be used for power failures to the valves that will approximate the CDF related to “stranding” them closed. In this case, once an ESAS has registered and the HPI pumps are running, 45 minutes are assumed to be available for establishing the minimum flow path before pump failure occurs. For “valve stranding” to be an issue, the loss of power to the valve would have to occur between the time of the ESAS and the time to pump failure. Power failures before the ESAS would not present a problem for minimum flow recirculation because MU-V-36/37 fail “as-is”. Power failures after pump failure are not a concern because the pump will already have failed. Therefore, the pertinent portion of the valve power failure probability is for only 0.75 hours out of 24. Assuming that the likelihood of failure is constant over the 24 hour mission time, this correlates to a fraction of only 3.12E-02.

If this fraction is applied to the power inputs for the minimum flow recirculation valve failure logic, a more representative base case will be established with respect to CDF. From this model configuration, the importance of the power supplies for the minimum flow recirculation valves can then be calculated. As mentioned above, this approximation method assumes that power is initially available to isolate the MU-V-36/37 valves, which will not always be the case and overestimates the importance of the power failures.

The following table summarizes the changes that were made to the PRA model to establish the new “baseline” used to calculate the importance of the MU-V-36/37 power supply gates:

SAMA 4 – Model Changes

Gate and / or Basic Event ID and Description	Description of Change
MRG0001 (existing gate): MR (makeup pump recirculation path)	The following inputs were removed from this gate: • ED1AESV (existing gate): 480V MCC 1A ESV FAILS • EE1BESV (existing gate): 480V MCC 1B ESV FAILS The following inputs were added to this gate: • Gate MCC1A-FRACTION • Gate MCC1B-FRACTION
MCC1A-FRACTION (new AND gate)	The following inputs were included: • ED1AESV (existing gate): 480V MCC 1A ESV FAILS • RECIRC-FRACTION (new basic event: FRACTION OF TIME THAT FAILURE IS CRITICAL FOR MIN FLOW RECIRC

SAMA 4 – Model Changes

Gate and / or Basic Event ID and Description	Description of Change
RECIRC-FRACTION: FRACTION OF TIME THAT FAILURE IS CRITICAL FOR MIN FLOW RECIRC	New basic event representing the fraction of time that a failure of power to the MU-V-36 or 37 valves would result in a "Stranded" valve given that the valve has already closed (3.12E-02).
MCC1B-FRACTION (new AND gate)	The following inputs were included: • EE1BESV (existing gate): 480V MCC 1B ESV FAILS • RECIRC-FRACTION (new basic event: FRACTION OF TIME THAT FAILURE IS CRITICAL FOR MIN FLOW RECIRC
Similar changes were made to the LOOP recovered set of logic. The LOOP recovered logic is a reproduction of the base logic without power dependences that is used after power is recovered in a LOOP sequence.	

In this case, the RRW value for RECIRC-FRACTION, which captures the importance of both power supplied to the MU-V-36 and 37 valves for both the base and "power recovered" logic, is only 1.006 based on CDF and 1.002 for the Level 2 results, which is below the SAMA screening criteria of 1.01 and demonstrates that changes to the MU-V-36/37 power supply configuration would not be cost beneficial.

E.6.5 SAMA NUMBER 5: ENHANCE VALVES MU-V-76A/B AND MU-V-77A/B TO ALLOW FOR RAPID ALIGNMENT CHANGES IN ACCIDENT CONDITIONS

The current MU-V-76A/B and MU-V-77A/B valve configurations do not allow for rapid re-alignment during accident conditions. These valves are used to manipulate the flowpath for the "B" HPI pump between the seal injection and makeup flowpaths, but they also inherently determine whether the "A" or "C" pump can be aligned to the seal injection flowpath. For TMI-1, the capability to quickly align the "C" HPI pump for seal injection would reduce the risk of prominent accident sequences in which thermal barrier cooling has failed in conjunction with the "A" and "B" HPI pumps. Replacing MU-V-76A/B and MU-V-77A/B with MOVs operable from the main control room would allow TMI-1 to use the "C" HPI pump for seal injection and prevent seal LOCAs when the normal cooling methods are unavailable.

The normal conditions of the plant, which are reflected in the PRA model, show that the "C" pump is the important pump for establishing alternate seal injection and that the benefit is derived from changes to the MU-V-76A/B. However, plant operating practices can change and alterations to the normal alignment of the HPI system could shift the importance to the "A" division. In order to address alternate plant configurations and to provide maximum flexibility, both sets of valves are assumed to require modification.

E.6.5.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMA's averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

In order to represent this SAMA in the PRA, cutset changes were made to address the impact of replacing the MU-V-76A/B and MU-V-77A/B valves with MOVs. This method was chosen given that the valve alignment capability can easily be modified through the manipulation of an existing human failure event. In the TMI-1 model, the relevant basic event is the independent HEP INHINJ2_MUHHMUOA, which is set to 1.0 in the baseline model to reflect the inability to locally manipulate the valve in time to support seal injection. In this case, providing the capability to remotely operate the valve is considered to reduce the failure probability to at least 1.0E-02, which is reflected in the cutsets by changing the failure probability of the independent HEP from 1.0 to 1.00E-02. This action is present in a large number of cutsets with multiple other HEPs. Typically, these cases are reviewed as part of the HRA dependency analysis, but for this case, the base probability is 1.0 and the action is not included in any JHEPs because the action always fails due to timing concerns. Setting the probability to something other than 1.0 would normally require inclusion of the action in the dependency analysis to limit the credit taken when dependent conditions exist. No dependency analysis was performed for this SAMA quantification. In this case, excluding the dependency analysis maximizes the benefit of the SAMA and is conservative relative to the identification of cost beneficial SAMAs. The following table summarizes the model changes that were made:

SAMA 5 - Model Changes

Gate and / or Basic Event ID and Description	Description of Change
INHINJ2_MUHHMUOA: OPERATOR OPENS CROSS CONNECT VALVES MU-V-76A/B AND STARTS MU-P-1C	The basic event probability was changed from 1.0 to 1.00E-02.

The model changes identified above yielded a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk, as summarized below:

SAMA 5 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	2.22E-05	31.49	$109,455
Percent Change	-6.3%	-3.4%	-2.5%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 5 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	4.86E-11	4.86E-11	1.90E-10	2.46E-10	3.31E-08	1.41E-08	8.34E-09	3.16E-07	6.57E-07	1.63E-07	1.69E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.10	0.04	0.02	0.93	4.04	1.00	0.05
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$12,705	$44,202	$3,367	$236	$2	$2	$7	$9	$298	$127	$75	$2,841	$13,271	$3,293	$160

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.36E-10	2.08E-11	7.99E-08	1.43E-08	1.75E-07	2.75E-09	7.43E-07	2.89E-07	3.12E-06	1.20E-05	1.69E-08	2.33E-06	1.91E-08	2.22E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.22	0.04	0.24	0.00	1.00	0.39	6.93	3.19	0.00	0.62	0.01	31.49
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$2	$0	$755	$135	$669	$11	$2,838	$1,104	$19,594	$3,134	$4	$610	$5	$109,455

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 5 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$3,157,717	$113,994	2.0	$227,988

E.6.5.2 EXTERNAL FLOODING EVALUATION

This SAMA has a very limited impact on external flooding scenarios. For the external flooding cases, the three flood regimes are impacted differently:

- Floods over 310' msl: In these scenarios, the MU-V-76A/B and MU-V-77A/B are not used and the SAMA has zero impact.
- Floods between 305' and 310' msl: Most of the sequences are not impacted by the enhanced capabilities of the MU-V-76A/B and MU-V-77A/B valves as core damage is caused by failure of the flood gates (SBO case) or because a flood warning is not provided and no preparations are made for the flood (SBO case). Flood sequence "E" represents cases where the flood gates are correctly installed, but a loss of onsite power leads to core damage. These cases will cause a seal LOCA, which is the event this SAMA is primarily designed to prevent. As power recovery could not be performed rapidly enough for SAMA 5 to restore seal cooling and prevent the seal LOCA, the impact of this SAMA on sequence E sequence is negligible and is it is assumed to have no impact on the CDF.
- Floods below 305' mls: The only impact these flood scenarios have on the plant is the potential to cause a loss of offsite power. The CDF for this sequence is assumed to be reduced by the same fraction as the internal events CDF.

The following tables summarize the results of quantification strategy:

SAMA 5 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	8.10E-05	177.14	$542,081
Percent Change	0.0%	0.0%	0.0%

A further breakdown of this information is provided below according to release category.

SAMA 5 - External Flooding Contributions by Release Ca

Flood Category	>310'	305' to 310' Sequence A	305' to 310' Sequence B	305' to 310' Sequence C	305' to 310' Sequence D	305' to 310' Sequence E	305' to 310' Sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.34E-07	8.10E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.35	177.14
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,141	$542,081

Based on these results, the external flooding component of the averted cost-risk can then be calculated:

SAMA 5 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$15,541,298	$2,175

E.6.5.3 COST OF IMPLEMENTATION

The cost of this enhancement was estimated to be $3,150,000 by the TMI staff (Exelon 2007c).

E.6.5.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 5 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$227,988	$2,175	$230,163	$3,150,000	-$2,919,837

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.6 SAMA NUMBER 6: ADD CROSS-TIES WITHIN THE TRAINS OF COOLING SYSTEMS - DHR, DHCCW, DHRW

Some failure combinations that eliminate both trains of the DHR related cooling systems could be mitigated if cross-ties were available between trains of the DHR, DHRW, and DHCCW systems (not between the systems). For example, these cross-ties would be helpful in conditions where the flow path fails in one train while a pump failure or maintenance event disables the opposite train. To ensure the DHR cross-ties can be implemented in a timely manner for LPI requirements, the associated valves should be operable from the main control room.

The use of MOVs in the DHR cross-tie line is beneficial due to the relatively rapid response time required to support low pressure injection; therefore, the MOVs are suggested as part of the design. For the DHCCW and DHRW systems, which support the containment heat removal function of DHR, the time available to respond is much longer. Manual valves could be used for these cross-tie lines and the cross-tie reliability would not be greatly impacted.

E.6.6.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMA's averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

Cross-tie capability for the DHRW system was modeled by adding an AND gate under the gate HAG0001 for train A that was labeled HAG0001-1 and has top event RA (DHRW train A) and gate HAG0001-2 as its inputs. HAG0001-2 is an OR gate that accounts for failure of a proposed crosstie MOV (SAMA6XTMOV1-VAFD), operator failure to perform the crosstie operation (SAMA6-XTIE-HVAOA), failure of a proposed AC power dependency (top event MC, which represents MCC 1C ESV), and the top event for DHRW train B (RB). Similar logic changes were also applied to the model for DHRW train B under gate HBG0001.

For DHCCW, the model logic changes for crosstie capability between trains A and B were applied to gates that affected cooling support dependencies for the reactor building spray pumps, the makeup pumps, and DHR pumps. The affected gates for train A systems were

CSG0018 (reactor building spray pump BS-P-1A), HPGPUMPACOOLSUP1 (makeup pump MU-P-1A), and LPRG0007 (decay heat pump DH-P-1A). The crosstie logic for DHCCW train A, with train B being used as the backup source, is contained under the AND gate HPGPUMPACOOLSUP1-1. This AND gate contains system top event HA and OR gate HPGPUMPACOOLSUP1-2 as its inputs. HPGPUMPACOOLSUP1-2 contains system top HB, the common operator failure event SAMA6-XTIE-HVAOA, gate MC for AC power dependency, and a proposed crosstie MOV (SAMA6XTMOV2-VAFD). Logic for DHCCW train B was revised in a similar fashion for the following affected gates for ECCS train B components:

CSG00017	reactor building spray pump BS-P-1B
HQGPUMPCCOOLIN	makeup pump MU-P-1C
LPRG0019	decay heat pump DH-P-1B

The AND gate HQGPUMPCCOOLIN-1 (DHCCW train B and train A as backup fail) was used as the cooling support dependency for these three gates identified for train B ECCS components. The inputs to HQGPUMPCCOOLIN-1 are system top HB (DHCCW train B) and the OR gate HQGPUMPCCOOLIN-2 (DHCCW train A fails as backup). The inputs to gate HQGPUMPCCOOLIN-2 are system top HA, the common operator failure event SAMA6-XTIE-HVAOA, gate MC for AC power dependency, and the proposed crosstie MOV (SAMA6XTMOV2-VAFD).

For the DHR system, two system top events representing different functions of this system were affected, namely gate LPI (LPI trains A and B fail), and gate DHR (DHR trains A and B fail). LPI is an AND gate with two inputs: AND gate LPIA-1 and AND gate LPIB-1. Inputs to LPIA-1 include OR gate LPIA for failure of LPI train A and OR gate LPIA-2, which represents failure of LPI train B to backup train A. LPIA-2 contains the operator failure to perform cross-tie operations (SAMA6-XTIE-HVAOA), power dependency gate MC, gate LPIB for failure of LPI train B, and crosstie MOV failure event SAMA6XTMOV3-VAFD. Likewise, AND gate LPIB-1 contains OR gate LPIB for failure of LPI train B and OR gate LPIB-2, which represents failure of LPI train A to backup train B. LPIB-2 contains the operator failure to perform cross-tie operations (SAMA6-XTIE-HVAOA), power dependency gate MC, gate LPIA for failure of LPI train A, and crosstie MOV failure event SAMA6XTMOV3-VAFD. Identical logic changes were made to system top DHR, which involved AND gate DHRA-1 and AND gate DHRB-1. The only difference is that system top DHRA was used in place of LPIA and DHRB was used in place of LPIB. Similarly, DHRA-1 and DHRA-2 were used in place of LPIA-1 and LPIA-2; and DHRB-1 and DHRB-2 were used in place of LPIB-1 and LPIB-2.

In addition, all affected logic described above that is modeled within the logic structure for post-LOOP recovery scenarios was also modified, with gate names appended with the characters "-R".

The model changes identified above yielded a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk, as summarized below:

SAMA 6 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	2.06E-05	31.00	$108,864
Percent Change	-13.1%	-4.9%	-3.0%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 6 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	4.86E-11	4.86E-11	1.90E-10	2.46E-10	3.57E-08	1.42E-08	7.69E-09	3.19E-07	6.39E-07	1.57E-07	1.60E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.10	0.04	0.02	0.93	3.93	0.97	0.04
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$12,705	$44,202	$3,367	$236	$2	$2	$7	$9	$321	$128	$69	$2,868	$12,908	$3,171	$151

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.36E-10	2.08E-11	8.40E-08	1.42E-08	1.96E-07	2.75E-09	7.81E-07	2.62E-07	3.14E-06	1.03E-05	1.69E-08	2.33E-06	1.91E-08	2.06E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.24	0.04	0.26	0.00	1.05	0.35	6.97	2.76	0.00	0.62	0.01	31.00
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$2	$0	$794	$134	$749	$11	$2,983	$1,001	$19,719	$2,705	$4	$610	$5	$108,864

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 6 Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$3,093,415	$178,296	2.0	$356,592

E.6.6.2 EXTERNAL FLOODING EVALUATION

This SAMA has a very limited impact on external flooding scenarios. For the external flooding cases, the three flood regimes are impacted differently:

- Floods over 310’ msl: In these scenarios, flood waters fail the DHR system and the SAMA has zero impact.

- Floods between 305’ and 310’ msl: Most of the sequences are not impacted by the addition of the DHR system cross-ties as core damage is caused by failure of the flood gates (safety equipment flooded, SBO) or because a flood warning is not provided and no preparations are made for the flood (safety equipment flooded, SBO). Flood sequence “E” represents cases where the flood gates are correctly installed, but a loss of onsite power leads to core damage. These cases will cause a seal LOCA and for the small fraction of the scenario in which power is recovered, the cross-ties could be used to mitigate certain failures. The impact of this SAMA can be approximated by using the baseline internal events model to determine the percent contribution of the “power recovered” SBO sequences to the total SBO contribution. Then, if it is assumed that the relative distribution of “power recovered” sequences for the “E” flood sequence as the same as for the internal events model, the portion of the flood sequence “E” CDF impacted can be calculated. For this evaluation, it is assumed that SAMA implementation will eliminate all SBO “power recovered” risk.

- Floods below 305’ mls: The only impact these flood scenarios have on the plant is the potential to cause a loss of offsite power. For simplicity, the CDF for this sequence is assumed to be completely eliminated.

Based on the internal events model, SBO sequences contribute a CDF of 3.25E-06/yr while the power recovered SBO sequences contribute only 2.21E-08/yr. This indicates that the “power recovered” SBO evolutions contribute only 0.7 percent of the SBO CDF (2.21E-08 / 3.25E-06/yr * 100 = 0.7). For flood sequence “E”, the expected CDF reduction would then be 2.56E-08 (7.0E-03 * 3.66E-06 = 2.56E-08).

The following tables summarize the results of quantification strategy:

SAMA 6 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	8.08E-05	176.71	$540,710
Percent Change	-0.3%	-0.3%	-0.3%

A further breakdown of this information is provided below according to release category.

SAMA 6 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' Sequence A	305' to 310' Sequence B	305' to 310' Sequence C	305' to 310' Sequence D	305' to 310' Sequence E	305' to 310' Sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.63E-06	8.65E-08	0	8.08E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.63	0.25	0.00	176.71
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,628	$778	$0	$540,710

Based on these results, the external flooding component of the averted cost-risk can then be calculated:

SAMA 6 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$15,501,141	$42,332

E.6.6.3 COST OF IMPLEMENTATION

The cost of installing the powered DHR cross-tie was estimated to be $2,750,000 by the TMI staff (Exelon 2007c). The cross-ties for the DHCCW and DHRW systems are not required to be MOVs due to the longer times available for performing the cross-tie and while there would be a substantial additional cost related to the addition of these cross-ties, only the DHR cross-tie cost of $2,750,000 is used here based on the availability of information.

E.6.6.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 6 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$356,592	$42,332	$398,924	$2,750,000	-$2,351,076

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.7 SAMA NUMBER 7: USE FIRE SERVICE WATER AS AN ALTERNATE COOLING SOURCE FOR THE ICCW HEAT EXCHANGERS

For cases in which NSRW is unavailable due to hardware failures (e.g., flow diversion), the Fire Service Water system could be used to directly cool the ICCW heat exchangers for thermal barrier cooling support. Given that the ICCW pumps would be available for the relevant cases, a local, manual valve could be used for the alignment as time should be available for such an action.

E.6.7.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMA's averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

For this model revision, the fire service water system was used to provide a backup cooling water source in the event that NSRW is unavailable to supply cooling water to the ICCW heat exchangers, which in turn renders thermal barrier cooling for the RCP seals unavailable. A new input was added to existing gate SEG0005, which was an AND gate labeled SEG0005-1. Inputs to this gate included the top event for unavailability of the NSRW system (top event NR) and OR gate SEG0005-2. Inputs to gate SEG0005-2 include the top event for unavailability of the fire service water system (top event FS), a basic event representing mechanical failures associated with this alternate alignment (SAMA7-MECHANICAL), and a HEP event (SAMA7-FSW-HVHOA), which was assigned an assumed failure probability of 0.1 since actions are performed outside the MCR. As a simplification, the failure probability for SAMA7-MECHANICAL was assigned an assumed unavailability of 1.0E-3. Model logic changes were not required for post-LOOP recovery scenarios as seal cooling is not applicable to those accident scenarios.

Similar model changes were performed under gate SEG0004 to credit this SAMA for ICCW "B" train cooling.

The model changes identified above yielded a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk, as summarized below:

SAMA 7 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	2.07E-05	30.62	$107,565
Percent Change	-12.7%	-6.1%	-4.2%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 7 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	4.86E-11	4.86E-11	1.90E-10	2.46E-10	3.37E-08	1.41E-08	8.34E-09	3.15E-07	6.13E-07	1.52E-07	1.65E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.10	0.04	0.02	0.92	3.77	0.93	0.05
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$12,705	$44,202	$3,367	$236	$2	$2	$7	$9	$303	$127	$75	$2,832	$12,383	$3,070	$156

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
$Freq.(/yr)_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
$Freq.\ (/yr)_{SAMA}$	2.36E-10	2.08E-11	7.99E-08	1.43E-08	1.70E-07	2.75E-09	7.43E-07	2.85E-07	3.06E-06	1.06E-05	1.69E-08	2.31E-06	1.91E-08	2.07E-05
$Dose\text{-}Risk_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
$Dose\text{-}Risk_{SAMA}$	0.00	0.00	0.22	0.04	0.23	0.00	1.00	0.38	6.79	2.83	0.00	0.62	0.01	30.62
$OECR_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
$OECR_{SAMA}$	$2	$0	$755	$135	$649	$11	$2,838	$1,089	$19,217	$2,778	$4	$605	$5	$107,565

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 7 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$3,064,992	$206,719	2.0	$413,438

E.6.7.2 EXTERNAL FLOODING EVALUATION

This SAMA can potentially impact scenarios in which AC power is available and the safety equipment has not been flooded. For the external flooding cases, the three flood regimes are impacted differently:

- Floods over 310' msl: In these scenarios, all safety equipment is flooded and this SAMA has no impact on the risk.

- Floods between 305' and 310' msl: Most of the sequences could not be impacted by this SAMA as core damage is caused by failure of the flood gates (safety equipment is flooded) or because a flood warning is not provided and no preparations are made for the flood (safety equipment is flooded). Flood sequence "E" represents cases where the flood gates are correctly installed, but a loss of onsite power leads to core damage. In these cases, the ensuing SBO results in a seal LOCA, which is the event SAMA 7 was designed to prevent when power is available. Given that a seal LOCA will occur for sequence "E" whether or not SAMA 7 is implemented, it has no impact on the sequence "E" CDF.

- Floods below 305' mls: The only impact these flood scenarios have on the plant is the potential to cause a loss of offsite power. In order to simplify the quantification of this SAMA, it is assumed that the SAMA 7 eliminates all risk from these floods.

The following tables summarize the results of these changes:

SAMA 7 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	8.08E-05	176.79	$540,940
Percent Change	-0.3%	-0.2%	-0.2%

A further breakdown of this information is provided below according to release category.

SAMA 7 External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' Sequence A	305' to 310' Sequence B	305' to 310' Sequence C	305' to 310' Sequence D	305' to 310' Sequence E	305' to 310' Sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	0.00E+00	8.08E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.00	176.79
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$0	$540,940

Based on these results, the external flooding component of the averted cost-risk can then be calculated:

SAMA 7 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$15,507,657	$35,816

E.6.7.3 COST OF IMPLEMENTATION

Palisades estimated $2.9 million for Fire water cooling to CCW HXs (NMC 2005), Calvert Cliffs estimated $565k for alt DHR cooling (BGE 1998), and Brown's Ferry estimated $1 million for Fire Water to DHR HXs (TVA 2003). The Brown's Ferry estimate is used for TMI.

E.6.7.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 7 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$413,438	$35,816	$449,254	$1,000,000	-$550,746

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.8 SAMA NUMBER 8: AUTOMATE REACTOR COOLANT PUMP TRIP ON HIGH MOTOR BEARING COOLING TEMPERATURE

Seal LOCAs resulting from operator failures to trip the RCPs on loss of motor bearing cooling could be reduced if high temperature sensors were installed on motor bearing cooling water lines to provide automatic trip signals.

E.6.8.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMA's averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

To simulate the improved capability of tripping the RCPs upon loss of NSCCW cooling to the motor and pump bearings, the HEP event OTHOT1_RCPTHP1OA was reduced by a factor of 10, from a failure probability of 1.44E-2 to 1.44E-3. Also, to account for the automation of the RCP trip function, all JHEPs including OTHOT1_RCPTHP1OA were set to 0.0.

While the installation of additional trip logic would introduce a previously non-existing source of spurious RCP trip signals that would increase plant risk, no reliable means of estimating the increase in the RCP trip frequency has been identified. As a result, no strategy to quantify the potential increase in risk related to implementation of this SAMA was developed for this quantification.

No requantification of the PRA model was required given that all of the changes outlined above could be performed in the cutset files.

The following table summarizes the data changes that were made:

SAMA Number 8 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
OTHOT1_RCPTHP1OA: OPERATOR FAILS TO TRIP REACTOR COOLANT PUMP ON LOSS OF NSCCW	The basic event probability was changed from 1.44E-02 to 1.44E-03.
JHHEML-HOT1HEPOA: NSHEML_HER-HP2OA AND OTHOT1_RCPTHP1OA	This basic event probability was set to 0.0.
JHHNS10HOT1HEPOA: NSHNS6-----HHXOA AND OTHOT1_RCPTHP1OA	This basic event probability was set to 0.0.
JHHNS6-HOT1HEPOA: NSHNS6-----HHXOA AND OTHOT1_RCPTHP1OA	This basic event probability was set to 0.0.
JHHNSHOTHEOHEPOA: JHHNS10HOT1HEPOA AND GSHEO1A----HDGOA	This basic event probability was set to 0.0.
JHHNSHOTHMRHEPOA: JHHNS10HOT1HEPOA AND MRHMR1-----HMUOA	This basic event probability was set to 0.0.
JHHOT1-HMR1HEPOA: OTHOT1_RCPTHP1OA AND MRHMR1-----HMUOA	This basic event probability was set to 0.0.
JHHOT1-XTIEHEPOA: OTHOT1_RCPTHP1OA AND NR-NRSRXTIEHVAOA	This basic event probability was set to 0.0.
JHHOTHMRXTIHEPOA: OTHOT1_RCPTHP1OA; MRHMR1-----HMUOA; NR-NRSRXTIEHVAOA	This basic event probability was set to 0.0.

The model changes identified above yielded a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk, as summarized below:

SAMA 8 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	2.06E-5	25.28	$91,111
Percent Change	-13.2%	-22.5%	-18.8%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 8 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
$Freq.(/yr)_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
$Freq. (/yr)_{SAMA}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.78E-08	1.46E-08	8.54E-09	3.16E-07	6.00E-07	1.60E-07	2.05E-08
$Dose\text{-}Risk_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06

SAMA 8 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Dose-Risk$_{SAMA}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	3.69	0.98	0.06
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$340	$131	$77	$2,841	$12,120	$3,232	$194

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.07E-07	2.75E-09	7.45E-07	2.89E-07	3.06E-07	1.32E-05	1.69E-08	2.32E-06	1.91E-08	2.06E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.22	0.04	0.28	0.00	1.01	0.39	0.68	3.52	0.00	0.62	0.01	25.28
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$2	$0	$756	$135	$791	$11	$2,846	$1,104	$1,922	$3,459	$4	$608	$5	$91,111

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 8 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$2,654,373	$617,338	2.0	$1,234,676

E.6.8.2 EXTERNAL FLOODING EVALUATION

This SAMA has no impact on external flooding scenarios. For the external flooding cases, the three flood regimes are impacted differently:

- Floods over 310' msl: In these scenarios, flood waters fail the safety equipment and the SAMA has zero impact.
- Floods between 305' and 310' msl: Most of the sequences could not be impacted by this SAMA as core damage is caused by failure of the flood gates (safety equipment is flooded) or because a flood warning is not provided and no preparations are made for the flood (safety equipment is flooded). Flood sequence "E" represents cases where the flood gates are correctly installed, but a loss of onsite power leads to core damage. In these cases the LOOP trips the RCPs so the auto trip function is not required. In addition, the ensuing SBO results in a seal LOCA, which is the event SAMA 8 was designed to prevent. Given that a

seal LOCA will occur for sequence "E" whether or not SAMA 8 is implemented, it has no impact on the sequence "E" CDF.

- Floods below 305' mls: The only impact these flood scenarios have on the plant is the potential to cause a loss of offsite power. Given that a LOOP event will trip the RCPs, SAMA 8's auto trip function is not required and it has no impact on these flood sequences.

In summary, this SAMA has no measurable impact on the external flooding contributors, as shown in the following tables:

SAMA 8 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	8.11E-05	177.16	$542,159
Percent Change	0.0%	0.0%	0.0%

A further breakdown of this information is provided below according to release category.

SAMA 8 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' Sequence A	305' to 310' Sequence B	305' to 310' Sequence C	305' to 310' Sequence D	305' to 310' Sequence E	305' to 310' Sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159

Based on these results, the external flooding component of the averted cost-risk can then be calculated:

SAMA 8 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$15,543,473	$0

E.6.8.3 COST OF IMPLEMENTATION

The cost of this enhancement was estimated to be $145,000 by the TMI staff (Exelon 2007c).

E.6.8.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 8 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$1,234,676	$0	$1,234,676	$145,000	$1,089,676

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive.

E.6.9 SAMA NUMBER 9: PROCEDURALIZE LOCAL ADV OPERATION

TMI-1 has procedures to perform the local ADV operations that are not credited in the PRA model (the failure probability is set to 1.0). If the available procedures are credited and used to allow local operation of the ADVS for cooldown/depressurization after loss of remote capability, the RRW value of the operator action would be reduced below the SAMA review threshold. This SAMA is used demonstrate that the RRW for this operator action would be below the SAMA review threshold if appropriate credit were taken and that no SAMAs are required to address local ADV operations.

For this case, an HEP of 0.1 is assumed for the action (AV-LOCADV--HCDOA). The model does not contain any JHEPs that include AV-LOCADV--HCDOA; therefore, no additional changes are required. This change was made directly in the cutsets and no model requantification was required, as summarized below:

SAMA 9 - Model Changes

Gate and / or Basic Event ID and Description	Description of Change
AV-LOCADV--HCDOA: OPERATOR ACTION FAILURE TO LOCALLY OPERATE ADVS ON LOSS OF AIR	Basic event probability changed from 1.0 to 1.00E-01.

In this case, the RRW value for AV-LOCADV--HCDOA was reduced to 1.005 for CDF and 1.004 for the Level 2 results. As these are both below the SAMA screening criteria of 1.01, this assessment demonstrates that enhancing local ADV operation would not be cost beneficial.

E.6.10 SAMA NUMBER 10: AUTOMATE BWST REFILL

Failure to refill the BWST is a large contributor to some SGTR sequences, especially those in which the main steam ADVs fail to operate (including operator errors). Automating the refill function would improve the reliability of this process and reduce the contributions from prominent SGTR sequences by providing a long term high pressure injection source. While isolation of the break is a more desirable approach to mitigating SGTR events, providing long term primary side injection is a potential means of preventing core damage and is considered to result in a success path by providing time to cool down the RCS and to recover isolation capability.

Automation of the BWST refill function will require linking tank level sensors/transmitters with logic that will start the transfer pumps, open the valves in the flowpath, and return the system to standby when the tank is refilled. This SAMA also requires that an adequate volume of boron will be available for at least 24 hours (without operator intervention) given the largest expected leak rate for SGTR initiating events.

It is possible that refill of the BWST would be capable of mitigating some ISLOCA events, but because an evaluation of Auxiliary Building flooding from ISLOCA flow has not been performed, no credit is taken for ISLOCA cases.

E.6.10.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of SAMA 10's averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

In order to represent this SAMA in the PRA, cutset changes were made to address the impact of automating the BWST refill function. This method was chosen given that BWST refill reliability can easily be modified through the manipulation of existing human failure events. In the TMI-1 model, the relevant basic events include an independent event as well as joint human error events. In this case, automating operation of the refill system (with human backup) is considered to reduce the failure probability to at least 1.0E-04, which is reflected by changing the failure probability of the independent HEP from 2.65E-02 to 1.0E-04. Because automation of the function basically removes it from the joint human error events, those events are set to 0.0. If the combinations of the remaining actions are important to the model, they would be treated in separate events and the development of new combinations is not required. The following table summarizes the model changes that were made:

SAMA 10 - Model Changes

Gate and / or Basic Event ID and Description	Description of Change
BWST-HRE27-HTKOA: FAILURE TO REFILL BWST (SPLIT FRAC REV)	The basic event probability was changed from 2.65E-02 to 1.0E-04.
JHAHCD4RE27HEPOA: AVHCD4_FF--HCDOA AND BWST-HRE27-HTKOA (JHEP addressing BWST refill and cooldown via secondary side)	The basic event probability was changed from 9.17E-05 to 0.0.
JHHRE27HL1AHEPOA: BWST-HRE27-HTKOA AND DLHHL1A----HVHOA (JHEP addressing BWST refill and opening drop line for DHR cooling)	The basic event probability was changed from 2.00E-04 to 0.0.
JHHEF2HRE27HEPOA: AVHEF2_FF--HCDOA AND BWST-HRE27-HTKOA (JHEP addressing BWST refill and manually initiating cooldown using the OTSG)	The basic event probability was changed from 1.3E-03 to 0.0.
JHHCD5HRE27HEPOA: DPHCD5-FF--HDPOA AND BWST-HRE27-HTKOA (JHEP addressing BWST refill and manual pressurization with the RCPs unavailable)	The basic event probability was changed from 1.90E-04 to 0.0.
JHHIGHREHHLHEPOA: IGHIG1_HER-HSGOA, BWST-HRE27-HTKOA, and DLHHL1A----HVHOA (JHEP addressing BWST refill, failure to isolate a SGTR, and opening drop line for DHR cooling)	The basic event probability was changed from 5.0E-07 to 0.0. (Event was not in cutsets)

The model changes identified above yielded a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk, as summarized below:

SAMA 10 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	2.29E-05	28.06	$90,062
Percent Change	-3.4%	-14.0%	-19.8%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 10 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	5.86E-08	1.19E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	0.34	6.81	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$1,629	$33,082	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.29E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	28.06
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$90,062

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 10 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$2,780,687	$491,024	2.0	$928,048

E.6.10.2 EXTERNAL FLOODING EVALUATION

This SAMA is of importance in SGTR events where RCS inventory leaves the containment and is unavailable for recirculation from the sump. For the external flooding cases, this is not an issue as the reactor is tripped by a manual shutdown rather than an SGTR event. While LOCAs are likely in external flooding scenarios due to SBO induced seal LOCAs, the sump would be available if AC power was subsequently recovered. No measurable risk reduction is believed to result from implementation of this SAMA for external flooding, as shown below:

SAMA 10 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	8.11E-05	177.16	$542,159
Percent Change	0.0%	0.0%	0.0%

A further breakdown of this information is provided below according to release category.

SAMA 10 - External Flooding Contributions by Release Ca

Flood Category	>310'	305' to 310' sequence A	305' to 310' sequence B	305' to 310' sequence C	305' to 310' sequence D	305' to 310' sequence E	305' to 310' sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
Base Dose-Risk	1.33E+02	1.31E+01	1.90E-01	1.89E+00	1.79E+01	1.07E+01	2.50E-01	3.70E-01	1.77E+02
SAMA Dose-Risk	1.33E+02	1.31E+01	1.90E-01	1.89E+00	1.79E+01	1.07E+01	2.50E-01	3.70E-01	1.77E+02
Base OECR	4.06E+05	4.01E+04	5.98E+02	5.77E+03	5.48E+04	3.29E+04	7.78E+02	1.22E+03	$542,159
SAMA OECR	4.06E+05	4.01E+04	5.98E+02	5.77E+03	5.48E+04	3.29E+04	7.78E+02	1.22E+03	$542,159

The external flooding component of the averted cost-risk for this SAMA is, therefore, $0:

SAMA 10 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$15,543,473	$0

E.6.10.3 COST OF IMPLEMENTATION

The cost of this enhancement was estimated to be $3,800,000 by the TMI staff (Exelon 2007c).

E.6.10.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 10 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$982,048	$0	$982,048	$3,800,000	-$2,817,952

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.11 SAMA NUMBER 11: ENHANCE EXTREME EXTERNAL FLOODING MITIGATION EQUIPMENT TO ADDRESS SBO AND LOSS OF SEAL COOLING SCENARIOS

Making the extreme flooding equipment proposed in SAMA 32 useful for SBO conditions, especially those with TD EFW failure, would require permanently mounting the submersible pumps so that the suctions could easily be swapped from a piped water source to the flood water source. Permanently installing the portable generator and the pumps so that they could be auto aligned (and manually aligned from the MCR should auto alignment fail) to support seal cooling would address both SBO and non-SBO loss of seal cooling cases through the ability to rapidly align alternate seal cooling.

It is recognized that the requirements of this SAMA are extreme, but in order to mitigate an SBO with EFW failures, it is necessary to provide alternate power to support a means of heat removal. Long term heat removal can be accomplished either by maintaining primary integrity (through RCP seal protection) and using the secondary side systems for heat removal, or through some form of a feed and bleed method. However, a feed and bleed method requires a DHR system that will allow recirculation in order to prevent containment overfill. The added complexity of installing an SBO capable DHR system is considered to be at least as difficult as automating the 480V AC generator alignment, which is proposed by this SAMA. While this SAMA has been retained on the SAMA list due to flooding considerations, the simpler solution to providing long term SBO survivability given EFW failure for internal event initiators is considered in SAMA 24.

E.6.11.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMA's averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

To simulate implementation of this SAMA, the cutsets from SAMA 1 were used as a starting point as they addressed the ability to prevent a seal LOCA given failure of the “A” and “B” EDGs. In order to capture the additional SAMA 11 capabilities of providing core cooling in an SBO even with turbine driven EFW failure, the important EDG and AFW equipment failures were set to zero. Setting these events to zero simulates recovery from these failures by the SAMA 11 equipment. The following table lists the basic event data changes that were made to the SAMA 1 cutset file to quantify the impact of this SAMA:

SAMA 11 - Model Changes

Gate and / or Basic Event ID and Description	Description of Change
EFEF-P-1----P7FS: TURBINE-DRIVEN PUMP EF-P-1 FAILS TO START	The basic event probability was changed from 4.66E-03 to 0.0.
EFEFP1------P7FR: TURBINE-DRIVEN PUMP EF-P-1 FAILS TO RUN	The basic event probability was changed from 5.06E-02 to 0.0.
EF-CCFEFW-LETHAL: LETHAL SHOCK TO THE EFW SYSTEM DUE TO COMMON CAUSE FAILURES	The basic event probability was changed from 4.25E-04 to 0.0.
GA1ADG------DGFS: DIESEL GENERATOR 1A FAILS TO START	The basic event probability was changed from 1.13E-02 to 0.0.
GA-EDG-1A---DGFR: DIESEL 1A FAILS TO RUN	The basic event probability was changed from 2.07E-02 to 0.0.
GA-EG-Y-1A--DGMM: Emergency Diesel Generator 1A in Maintenance	The basic event probability was changed from 1.61E-02 to 0.0.
GB1BDG------DGFS: DIESEL GENERATOR 1B FAILS TO START	The basic event probability was changed from 1.13E-02 to 0.0.
GB-EDG-1B---DGFR: DIESEL 1B FAILS TO RUN	The basic event probability was changed from 2.07E-02 to 0.0.
GB-EG-Y-1B--DGMM: Emergency Diesel Generator 1B in Maintenance	The basic event probability was changed from 1.61E-02 to 0.0.
GSEG-Y-4----DGFS: STATION BLACKOUT DG FAILS TO START	The basic event probability was changed from 1.13E-02 to 0.0.
GS-SBODG----DGFR: SBO DIESEL FAILS TO RUN	The basic event probability was changed from 2.07E-02 to 0.0.
GS-EG-Y-4---DGMM: SBO Diesel Generator in Maintenance	The basic event probability was changed from 1.30E-2 to 0.0.
GA-1A1BSBO-CDGFR: EDG CCF Run DG-1A;DG-1B;DG-SBO	The basic event probability was changed from 1.53E-04 to 0.0.
GAEDG-STARTCDGFS: EDG Fail to Start CCF DG-All 3	The basic event probability was changed from 5.25E-05 to 0.0.

The model changes identified above yielded a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk, as summarized below:

SAMA 11 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	1.57E-05	24.43	$87,640
Percent Change	-33.8%	-25.1%	-21.9%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 11 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.47E-07	1.22E-06	1.80E-07	1.16E-08	4.21E-11	4.21E-11	2.37E-11	6.68E-11	1.11E-08	1.10E-08	3.35E-10	2.28E-07	5.18E-07	7.85E-07	1.22E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.56	6.98	0.91	0.06	0.00	0.00	0.00	0.00	0.03	0.03	0.00	0.67	3.19	4.83	0.03
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$12,427	$33,916	$3,348	$216	$2	$2	$1	$3	$100	$99	$3	$2,050	$10,464	$15,857	$115

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	3.41E-11	0.00E+00	8.41E-09	8.11E-10	1.24E-07	4.24E-10	7.80E-08	1.32E-08	8.26E-07	1.09E-05	1.25E-08	3.38E-07	4.81E-10	1.57E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.02	0.00	0.17	0.00	0.11	0.02	1.83	2.90	0.00	0.09	0.00	24.43
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$0	$0	$79	$8	$474	$2	$298	$50	$5,187	$2,849	$3	$89	$0	$87,640

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 11 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$2,452,029	$819,682	2.0	$1,639,364

E.6.11.2 EXTERNAL FLOODING EVALUATION

The severe flooding guidelines were originally credited in the IPEEE for both floods above 310' msl as well as for floods between 305' and 310' msl. Due to a more limited preparation time for the 305' to 310' msl floods, the failure probability was assumed to be 0.5 rather than the 0.255 used for the 310' msl floods. For floods below 305' msl, no credit was taken for the severe flooding guidelines as the submersible pumps used for secondary side makeup require flood water in the turbine building for a suction source. Given that this SAMA includes provisions for an alternate secondary side pump suction source, it is assumed that credit could be taken for the floods below 305', as well. The credit taken for this SAMA will be the same for all flood scenarios given that the proposed changes will reduce the manipulation time to a point where it is short (within 13 minutes for auto alignments cause by undervoltage) in comparison to the available time for all of the scenarios (on the order of 18-24 hours from the action cue). This factor reduces the impacts of time stress on the alignment failure probability.

For the purposes of this analysis, implementation of this SAMA is assumed to reduce the HEP for alignment of the external flooding measures from 1.1E-01 to 1.0E-04. The large reduction is based on the fact that SAMA 11 automates the system response and no operator action is required. As a result, there is no need to consider operator dependence factors for the initiation failure probability. In addition, the availability of the diverse, alternate portable AC generator is considered to reduce the failure probability of the flood-safe AC power source from 1.43E-01 to 2.04E-02 (1.43E-01 * 1.43E-01 = 2.04E-2, which assumes completely independent generators). This results in a total failure probability of 2.05E-02 (1.0E-04 + 2.04E-02 = 2.05E-02) for the severe flooding mitigation strategy.

Because the severe flooding guidelines were credited differently in each of the flood ranges, three separate strategies are required to obtain the revised core damage frequencies for the flooding scenarios:

- Floods >310' msl: The CDF for this scenario was calculated in the IPEEE as the product of the flood frequency and the failure probability for the alignment of the severe flooding mitigation strategy. As a result, the revised frequency can be obtained by multiplying the base CDF by the ratio of SAMA based severe flood mitigation failure probability to the baseline severe flood mitigation failure probability (2.05E-02 / 2.55E-01 = 8.03E-02).

- Floods between 305' and 310' msl: In the IPEEE, a multiplier of 0.5 was applied to each of the sequences in the flooding event tree to represent the potential to avert the flood using the severe flooding guidelines. The CDFs for these sequences can be made to reflect implementation of this SAMA by multiplying each sequence specific CDF by the ratio of SAMA based severe flood mitigation failure probability to the baseline severe flood mitigation failure probability (2.05E-02 / 5.0E-01 = 4.10E-02).

- Floods below 305' msl: No credit was taken for the severe flooding guidelines for these cases in the IPEEE and as a result, the CDF can be directly multiplied by 2.05E-02.

The results of this process are summarized below:

SAMA 11 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	5.81E-06	12.45	$38,036
Percent Change	-92.8%	-93.0%	-93.0%

A further breakdown of this information is provided below according to release category.

SAMA 11 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' sequence A	305' to 310' sequence B	305' to 310' sequence C	305' to 310' sequence D	305' to 310' sequence E	305' to 310' sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	5.12E-06	2.53E-07	2.67E-09	3.63E-08	2.45E-07	1.47E-07	3.47E-09	5.13E-09	5.81E-06
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	10.66	0.53	0.01	0.08	0.72	0.43	0.01	0.01	12.45
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$32,598	$1,610	$24	$231	$2,199	$1,318	$31	$25	$38,036

The external flooding based averted cost-risk for this SAMA is shown below:

SAMA 11 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$1,094,145	$14,449,328

E.6.11.3 COST OF IMPLEMENTATION

The cost of this enhancement was estimated to be $4,250,000 by the TMI staff (Exelon 2007c).

E.6.11.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 11 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$1,639,364	$14,449,328	$16,088,692	$4,250,000	$11,838,692

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive.

E.6.12 SAMA NUMBER 12: USE THE DHR SYSTEM AS AN ALTERNATE SUCTION SOURCE FOR HPI

Failures of the BWST suction path (MU-V-14A/B) to the HPI pumps will lead to core damage in scenarios requiring early makeup. Through implementation of procedure changes, the DHR system could be aligned to take suction from the BWST and supply flow to the HPI system to allow injection in these cases.

While the events that will cause failure of the HPI suction path are low probability events, the options to prevent core damage in those cases are extremely limited. The existing DHR and HPI piping provide an alternate path that could be used and credited if plant procedures and training were modified.

E.6.12.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMAs averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

In order to represent this SAMA in the PRA, the PRA model was changed to accommodate existing logic for valves DH-V-7A/B in the HPI system injection path logic. A new human error probability (HEP) event was added with a screening value of 0.1 (SAMA12-DHMUHVAOA) in conjunction with valve hardware failure events and power dependencies. Logic representing the dependence on the DHR system itself was not included in the DH-V-7A/B suction path. Inclusion of the DHR dependence would reduce the averted cost-risk calculated for this SAMA, but the impact is estimated to be small given that the alternate suction path failures would be dominated by the 0.1 failure probability of the operator action and the common valve power dependences. The changes made to the model are summarized in the following table:

SAMA 12 - Model Changes

Gate and / or Basic Event ID and Description	Description of Change
Gate HPG00MAC: NO FLOW FROM PUMP MU-P1A	Deleted the following gate: • Gate HPG00MBK: NO FLOW FROM MU-V-14AOR MU-V-14B Added the following gate: • Gate HPG00MBK-1 (new): NO SUCTION SOURCE FOR HPI
Gate HPG00MBK-1: NO SUCTION SOURCE FOR HPI	New AND gate representing the availability of both the BWST and the DHR heat exchangers as injection suction sources. The gate includes the following input: • Gate HPG00MBK (existing): NO FLOW FROM MU-V-14AOR MU-V-14B • Gate HPG00MBK-2 (new): HPI SUCTION VIA DH-V-7 MOVS
Gate HPG00MBK-2: HPI SUCTION VIA DH-V-7 MOVS	New OR gate representing the DHR system suction path for HPI. The gate includes the following input: • Gate HL (existing): HL (DH-V-7A/B failures)
Basic event SAMA12-DHMUHVAOA: OPERATOR FAILS TO ALIGN DHR TO MAKEUP PUMP SUCTION	New basic event representing the probability that the operators will fail to align the DHR system as the suction injection mode suction source for HPI. Failure probability = 0.1.
Similar changes have been made to the “power recovered” logic. The “power recovered” logic is used in portions of the LOOP tree in which offsite power has been restored and the power dependencies of the logic are removed to preclude failure of OSP from disabling equipment.	
Similar changes were also made to credit the MU-P-1B and MU-P-1C pumps with the alternate injection suction alignment from the DHR system.	

The model changes identified above yielded a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk, as summarized below:

SAMA 12 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	2.27E-05	31.64	$109,292
Percent Change	-4.2%	-3.0%	-2.6%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 12 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.47E-07	1.56E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	6.80E-07	1.63E-07	2.06E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.56	8.92	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.18	1.00	0.06
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$12,427	$43,368	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$13,736	$3,293	$195

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.11E-07	2.75E-09	7.44E-07	2.89E-07	3.14E-06	1.24E-05	1.68E-08	2.33E-06	1.91E-08	2.27E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.22	0.04	0.28	0.00	1.00	0.39	6.97	3.31	0.00	0.62	0.01	31.64
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$2	$0	$756	$135	$806	$11	$2,842	$1,104	$19,719	$3,251	$4	$610	$5	$109,292

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 12 - Non-External Flooding Averted Cost

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$3,172,492	$99,219	2.0	$198,438

E.6.12.2 EXTERNAL FLOODING EVALUATION

This SAMA is of importance in LOCA events where RCS inventory makeup is required using the HPI system suction from the BWST. For the external flooding cases, this is not an issue as the reactor is tripped by a manual shutdown (or a LOOP) rather than a LOCA event. While LOCAs are likely in external flooding scenarios due to SBO induced seal LOCAs, the HPI system would be unavailable in those cases during the SBO. There is some potential for this SAMA to provide a benefit in the flood induced SBO scenarios where AC power is recovered prior to core damage, but the likelihood of recovering power in the short amount of time to prevent core damage in believed to be very low for flood conditions and this SAMA is assumed to provide zero benefit. As a point of reference, the SBO sequences from the base model were quantified and the resulting cutsets were reviewed to determine the contribution of BWST suction failures after power recovery. There was no measurable contribution from suction path failures. The sequences quantified included those in which AC power was both recovered and not recovered, specifically:

- LOOP-055
- LOOP-057
- LOOP-058
- LOOP-059
- LOOP-062
- LOOP-064
- LOOP-066
- LOOP-067
- LOOP-068
- LOOP-069

As a result, this SAMA would not yield a measurable risk reduction for the external flooding events, as shown below:

SAMA 12 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	8.11E-05	177.16	$542,159
Percent Change	0.0%	0.0%	0.0%

A further breakdown of this information is provided below according to release category.

SAMA 12 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' sequence A	305' to 310' sequence B	305' to 310' sequence C	305' to 310' sequence D	305' to 310' sequence E	305' to 310' sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159

The external flooding component of the averted cost-risk for this SAMA is, therefore, $0:

SAMA 12 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$15,543,473	$0

E.6.12.3 COST OF IMPLEMENTATION

Procedure changes are estimated to be $50,000 (CPL 2004).

E.6.12.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 12 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$198,438	$0	$198,438	$50,000	$148,438

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive.

E.6.13 SAMA NUMBER 13: CHANGE IA SYSTEM LOGIC TO AUTOMATICALLY START IA-P-1A/B AFTER A LOW VOLTAGE TRIP IN CONJUNCTION WITH AN ESAS

The current IA system logic requires the operators to re-load the IA compressors on emergency power after a low voltage trip when an ESAS is registered. Automating the re-loading of these compressors would remove the requirement for the operators to perform this task in accident conditions. The scenarios of interest for this SAMA are turbine building steam line breaks that cause both a LOOP (due to adverse environmental conditions) and an ESAS, which will require the operators to reload the IA compressors. The importance of automating this action is driven by the short time that is available to prevent loss of seal cooling due to closure of MU-V-20, IC-V-3, and IC-V-4. The PRA indicates that the air supplies for these valves will deplete in 20 minutes after loss of IA and will go closed. While recovery may be possible after the initial closure, no credit is taken for such recovery actions in the model.

E.6.13.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMA's averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

The HEP event for failure to manually start the air compressors using emergency power from the station diesel generators (AMHAM2-----HC1OA) was changed from a failure probability of 8.88E-2 to 1.00E-05 to simulate the improved reliability due to proposed automatic restart logic. In addition, the JHEPs including AMHAM2-----HC1OA were set to zero to account for the removal of the operator from the dependence chain. The following table summarizes the changes that were made to the basic event data:

SAMA 13 - Model Changes

Gate and / or Basic Event ID and Description	Description of Change
AMHAM2-----HC1OA:	Basic event probability changed from 8.88E-02 to 1.00E-05.
JHHAM2-HEF1HEPOA: AMHAM2-----HC1OA AND EFHEF1_OPERH2HOA	Basic event probability set to 0.0.
JHHAM2HINJ1HEPOA: AMHAM2-----HC1OA AND INHINJ1_MUHHMUOA	Basic event probability set to 0.0.
JHHAM2HINJ4HEPOA: AMHAM2-----HC1OA AND INHINJ4_MUHHVCOA	Basic event probability set to 0.0.
JHHAMHEFHBWHEPOA: JHHAM2-HEF1HEPOA AND BWHBW1-----HP2OA	Basic event probability set to 0.0.

The model changes identified above yielded a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk, as summarized below:

SAMA 13 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	2.30E-05	31.17	$106,172
Percent Change	-3.0%	-4.4%	-5.4%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 13 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.00E-07	1.47E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.89E-08	1.46E-08	8.54E-09	3.16E-07	7.00E-07	1.64E-07	2.15E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.29	8.41	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.31	1.01	0.06
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$11,120	$40,866	$3,367	$236	$3	$3	$7	$11	$350	$131	$77	$2,841	$14,140	$3,313	$203

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.19E-07	2.75E-09	7.44E-07	2.89E-07	3.16E-06	1.28E-05	1.40E-08	2.34E-06	1.91E-08	2.30E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.22	0.04	0.30	0.00	1.00	0.39	7.02	3.41	0.00	0.62	0.01	31.17
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$2	$0	$756	$135	$837	$11	$2,842	$1,104	$19,845	$3,349	$4	$613	$5	$106,172

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 13 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$3,119,064	$152,647	2.0	$305,294

E.6.13.2 EXTERNAL FLOODING EVALUATION

This SAMA will have no measurable benefit for external flooding cases given that equipment is either flooded, an SBO and subsequent seal LOCA occurs (the main goal of this SAMA is to prevent seal LOCAs), or a LOOP will occur without an ESAS signal, as summarized below:

Floods over 310’ msl: In these scenarios, all safety equipment is flooded and this SAMA has no impact on the risk.

Floods between 305’ and 310’ msl: Most of the sequences are not impacted by this SAMA as core damage is caused by failure of the flood gates (safety equipment if flooded) or because a flood warning is not provided and no preparations are made for the flood (safety equipment is flooded). Flood sequence “E” represents cases where the flood gates are correctly installed, but a loss of onsite power leads to core damage. These scenarios will result in an SBO and a subsequent seal LOCA independent of the implementation status of SAMA 13.

Floods below 305’ mls: The only impact these flood scenarios have on the plant is the potential to cause a loss of offsite power. Given that IA will not require manual reload without a coincident ESAS and that an ESAS is not expected for a LOOP without a seal LOCA, implementation of SAMA 13 for seal LOCA prevention will not be beneficial.

Consequently, this SAMA would not yield a measurable risk reduction for the external flooding events, as shown below:

SAMA 13 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	8.11E-05	177.16	$542,159
Percent Change	0.0%	0.0%	0.0%

A further breakdown of this information is provided below according to release category.

SAMA 13 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' Sequence A	305' to 310' Sequence B	305' to 310' Sequence C	305' to 310' Sequence D	305' to 310' Sequence E	305' to 310' Sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159

Based on these results, the external flooding component of the averted cost-risk can then be calculated:

SAMA 13 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$15,543,473	$0

E.6.13.3 COST OF IMPLEMENTATION

The cost of this enhancement was estimated to be $950,000 by the TMI staff (Exelon 2007c).

E.6.13.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 13 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$305,647	$0	$305,647	$950,000	-$644,706

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.14 SAMA NUMBER 14: REPLACE HPI PUMP COOLING ALIGNMENT VALVES WITH MOVS

In the event that the normally aligned cooling source to a HPI pump fails, the current plant configuration requires local operation of the valves to swap the pump to the alternate cooling source. The time required to perform this action is considered to preclude it as a means of both preventing seal LOCAs in loss of seal cooling evolutions and for providing high pressure makeup. Replacing the valves with MOVs would allow the operators to rapidly align the alternate cooling source from the MCR in time to prevent a seal LOCA or provide high pressure injection.

E.6.14.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMA's averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

The ability to cross-connect cooling systems for the makeup pumps necessitated a change to the model logic for all three makeup pumps depending upon their ESAS alignments. The following paragraphs outline the model changes for each of the makeup pumps:

<u>Makeup Pump A Aligned to ESAS Train A:</u>

The system top event HA under AND gate HPGPUMPACOOLSUP1 was replaced with an AND gate named HPGPUMPACOOLSUP1-1, which contained top event HA and an OR gate named HPGPUMPACOOLSUP1-2 as its inputs. The inputs to HPGPUMPACOOLSUP1-2 were a new

HEP event (SAMA14-HEP-HVAOA), a basic event that accounted for combined mechanical and electrical failures (SAMA14AMECH-ELEC), and system top event NS for unavailability of the NSCCW system. The HEP event was assigned a failure probability of 0.01, which was based on assuming all actions required for realigning cooling water were capable of being performed from inside the main control room. The event SAMA14AMECH-ELEC was estimated to have an unavailability of 0.01, based on a generic combination of mechanical and electrical support dependency failures unique to makeup pump MU-P-1A.

<u>Makeup Pump A Aligned for RCP Seal Injection:</u>

The system top event NS under AND gate HPGPUMPACOOLSUP2 was replaced with an AND gate named HPGPUMPACOOLSUP2-1, which contained the system top event NS and a new OR gate named HPGPUMPACOOLSUP2-2. This new OR gate contained the HEP event SAMA14-HEP-HVAOA and basic event SAMA14AMECH-ELEC, which were both described above, and the system top event HA, simulating the loss of DHCCW train A.

<u>Makeup Pump B Cooling Water Dependency:</u>

The physical arrangement of the MU-P-1B cooling piping is such that complex back feeding and the installation of multiple, additional MOVs would be required to allow DHCCW to be used for pump cooling in place of NSRW. Exelon’s cost estimate for this SAMA does not include the costs associated with these types of changes; however, credit is taken in this evaluation for alternate MU-P-1B cooling. This conservative approach was used in order to provide a bounding assessment of the benefit related to alternate HPI pump cooling without expending the additional resources that would be required to fully develop the costs of providing DHCCW to MU-P-1B.

The system top event NS under OR gate HPGPUMPBCOOL was replaced with an AND gate named HPGPUMPBCOOL-1, which contained the system top event NS and a new OR gate named HPGPUMPBCOOL-2. This new OR gate contained the HEP event SAMA14-HEP-HVAOA described above and a new basic event SAMA14BMECH-ELEC, which was assigned an unavailability of 0.01, based on a generic combination of mechanical and electrical support dependency failures unique to makeup pump MU-P-1B. In addition, HPGPUMPBCOOL-2 also contained the system top event HA, simulating the loss of DHCCW train A.

Makeup Pump C Aligned to ESAS Train B:

The system top event HB under OR gate HQGPUMPCCOOLIN was replaced with an AND gate named HQGPUMPCCOOLIN-1, which contained top event HB and a new OR gate named HQGPUMPCCOOLIN-2 as its inputs. The inputs to HQGPUMPCCOOLIN-2 were the HEP event SAMA14-HEP-HVAOA described above, a basic event that accounted for combined mechanical and electrical failures unique to makeup pump MU-P-1C (SAMA14CMECH-ELEC), and system top event NS for unavailability of the NSCCW system.

In addition, all affected logic described above that is modeled within the logic structure for post-LOOP recovery scenarios was also modified, with gate names appended with the characters "-R".

The model changes identified above yielded a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk, as summarized below:

SAMA 14 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	1.97E-05	29.86	$105,634
Percent Change	-16.9%	-8.4%	-5.9%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 14 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	4.86E-11	4.86E-11	1.90E-10	2.46E-10	3.29E-08	1.42E-08	7.69E-09	3.19E-07	5.34E-07	1.57E-07	1.60E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.10	0.04	0.02	0.93	3.28	0.97	0.04
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$12,705	$44,202	$3,367	$236	$2	$2	$7	$9	$296	$128	$69	$2,868	$10,787	$3,171	$151

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.36E-10	2.08E-11	8.40E-08	1.42E-08	1.63E-07	2.75E-09	7.81E-07	2.62E-07	3.01E-06	9.70E-06	1.69E-08	2.32E-06	1.91E-08	1.97E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.24	0.04	0.22	0.00	1.05	0.35	6.69	2.59	0.00	0.62	0.01	29.86
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$2	$0	$794	$134	$623	$11	$2,983	$1,001	$18,928	$2,542	$4	$608	$5	$105,634

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 14 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$2,987,676	$284,035	2.0	$568,070

E.6.14.2 EXTERNAL FLOODING EVALUATION

This SAMA will have limited benefit for external flooding cases given that equipment is either flooded, an SBO occurs, or the combined probability of the flood initiators with loss of HPI pump cooling evolutions is so low that the SAMA will not provide a measurable risk reduction, as summarized below:

Floods over 310’ msl: In these scenarios, all safety equipment is flooded and this SAMA has no impact on the risk.

Floods between 305’ and 310’ msl: Most of the sequences are not impacted by this SAMA as core damage is caused by failure of the flood gates (safety equipment if flooded) or because a flood warning is not provided and no preparations are made for the flood (safety equipment is flooded). Flood sequence “E” represents cases where the flood gates are correctly installed, but a loss of onsite power leads to core damage. These are SBO scenarios in which SAMA 14 would not typically provide a benefit. In the event that AC power is recovered before core damage occurs, SAMA 14 could be beneficial if HPI pump cooling was also lost in the evolution; however, review of the baseline SBO sequence importance list shows that the largest RRW for any DHCCW or DHRW event is 1.001 and all NSCCW events fell below the truncation limit of the quantification and are not even included in the importance list. Therefore, no credit is taken for this SAMA in flood sequence “E”.

Floods below 305' mls: The only impact these flood scenarios have on the plant is the potential to cause a loss of offsite power. There is some potential for SAMA 14 to provide a benefit for these cases and for the purposes of simplifying the quantification, SAMA 14 is assumed to eliminate all risk for these flood evolutions.

The following tables summarize the results of quantification strategy:

SAMA 14 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	8.08E-05	176.79	$540,940
Percent Change	-0.3%	-0.2%	-0.2%

A further breakdown of this information is provided below according to release category.

SAMA 14 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' Sequence A	305' to 310' Sequence B	305' to 310' Sequence C	305' to 310' Sequence D	305' to 310' Sequence E	305' to 310' Sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	0.00E+00	8.08E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.00	176.79
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$0	$540,940

Based on these results, the external flooding component of the averted cost-risk can then be calculated:

SAMA 14 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$15,507,657	$35,816

E.6.14.3 COST OF IMPLEMENTATION

The cost of this enhancement was estimated to be $3,150,000 by the TMI staff (Exelon 2007c).

E.6.14.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 14 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$568,070	$35,816	$603,886	$3,150,000	-$2,546,114

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.15 SAMA NUMBER 15: AUTOMATIC SWAP TO RECIRCULATION MODE

The operator action to swap to recirculation mode is a key action for LOCA scenarios. Automating this function would improve the reliability of this action, especially in the rapidly evolving events where other actions are competing for the attention of the operators.

This SAMA should provide the capability to automatically align high or low pressure recirculation mode, depending on the conditions of the plant.

E.6.15.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMAs averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

To simulate the automatic swapover from injection to recirculation, the HEP events SAHSR1-----HSROA (for large LOCAs) and SAHSR2-----HSROA (for non-large LOCAs) were set to 1.00E-05 to simulate automation of the action. The corresponding JHEP was set to 0.0 to capture the removal of the recirculation action from the dependence chain. Given that these changes include only the modification of basic event probabilities, the changes were made to the cutset files and no model requantification was required. The cutset changes are summarized in the following table:

SAMA 15 - Model Changes

GATE AND / OR BASIC EVENT ID AND DESCRIPTION	DESCRIPTION OF CHANGE
SAHSR1-----HSROA: OPERATOR FAILS TO TAKE PROPER ACTION WITHIN ONE MINUTE	The basic event probability was changed from 1.71E-02 to 1.00E-05.
SAHSR2-----HSROA: OPERATOR FAILS TO TAKE PROPER ACTION WITHIN TEN MINUTE	The basic event probability was changed from 1.30E-04 to 1.00E-05.
JHHHL1AHSR2HEPOA: DLHHL1A----HVHOA AND SAHSR2-----HSROA (dependence between failure to swap to recirculation mode and failure to open dropline for DHR)	The basic event probability was changed from 2.00E-04 to 0.0.

The model changes identified above yielded a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk, as summarized below:

SAMA 15 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	2.26E-05	31.65	$109,449
Percent Change	-4.6%	-2.9%	-2.5%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 15 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)_{BASE}	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
$\text{Freq. (/yr)}_{SAMA}$	4.55E-07	1.56E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	6.78E-07	1.63E-07	2.07E-08
Dose-Risk_{BASE}	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk_{SAMA}	2.60	8.92	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.17	1.00	0.06
OECR_{BASE}	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR_{SAMA}	$12,649	$43,368	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$13,696	$3,293	$196

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.36E-10	2.08E-11	7.99E-08	1.43E-08	2.12E-07	2.75E-09	7.44E-07	2.89E-07	3.14E-06	1.23E-05	1.67E-08	2.33E-06	1.91E-08	2.26E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.22	0.04	0.29	0.00	1.00	0.39	6.97	3.28	0.00	0.62	0.01	31.65
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$2	$0	$755	$135	$810	$11	$2,842	$1,104	$19,719	$3,223	$4	$610	$5	$109,449

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 15 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$3,172,617	$99,094	2.0	$198,188

E.6.15.2 EXTERNAL FLOODING EVALUATION

This SAMA is of importance in LOCA events when the entire volume of the BWST has been injected and the only source of borated water for continued core cooling is the water that has collected in the containment sump. For the external flooding cases, this is not an issue as the reactor is tripped by a manual shutdown (or a LOOP) rather than a LOCA event. While LOCAs are likely in external flooding scenarios due to SBO induced seal LOCAs, the primary side injection systems would be unavailable in those cases during the SBO. There is some potential for this SAMA to provide a benefit in the flood induced SBO scenarios where AC power is recovered prior to core damage, but the likelihood of recovering power in the short amount of time to prevent core damage is very low for flood conditions and this SAMA will provide an extremely limited benefit.

To investigate this further, the SBO sequences from the base model were quantified and the resulting cutsets were reviewed to determine the contribution of manual recirculation alignment failures after power recovery. The sequences quantified included those in which AC power was both recovered and not recovered, specifically:

- LOOP-055
- LOOP-057

- LOOP-058
- LOOP-059
- LOOP-062
- LOOP-064
- LOOP-066
- LOOP-067
- LOOP-068
- LOOP-069

The only event identified in the cutsets was the JHEP event “JHHHL1AHSR2HEPOA” which accounted for only 0.1 percent of the SBO CDF. For the external flooding cases, the only two potential sequences that could be impacted by SAMA 15 are:

- Floods between 305’ and 310’ msl, sequence E: Most of the sequences are not impacted by this SAMA as core damage is caused by failure of the flood gates (the SBO EDG is flooded) or because a flood warning is not provided and no preparations are made for the flood (the SBO EDG is flooded). Flood sequence “E” represents cases where the flood gates are correctly installed, but a loss of onsite power leads to core damage. These SBO cases are considered to be similar to the internal events SBO cases.

- Floods below 305’ mls: The only impact these flood scenarios have on the plant is the potential to cause a loss of offsite power. While only a fraction of these cases would actually be SBOs, they are assumed to be 100% SBO cases for this evaluation.

Assuming that SAMA 15 can remove all of the 0.1 percent risk attributed to manual recirculation failures results in a 0.1 percent reduction of the sequences identified above. The change in risk is trivial compared with the overall external flooding contributions, as summarized below:

SAMA 15 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	8.11E-05	177.15	$542,125
Percent Change	0.0%	0.0%	0.0%

A further breakdown of this information is provided below according to release category.

SAMA 15 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' sequence A	305' to 310' sequence B	305' to 310' sequence C	305' to 310' sequence D	305' to 310' sequence E	305' to 310' sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.65E-06	8.65E-08	2.50E-07	8.11E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.70	0.25	0.37	177.15
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,826	$778	$1,217	$542,125

The external flooding component of the averted cost-risk for this SAMA is, therefore, $910:

SAMA 15 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$15,542,563	$910

E.6.15.3 COST OF IMPLEMENTATION

Multiple SAMA analyses have included estimates for this type of change, but the estimates vary by over a factor of 3.5:

- Oconee estimated the cost at over $1 million per unit (Duke 1998)
- Point Beach estimated the cost at over $1 million per unit (NMC 2004)
- Catawba estimated the cost at over $1 million (Duke 2001)
- Turkey Point estimated the cost to be about $450,000 (per unit) (FPL 2000)
- H.B. Robinson $265,000 (single unit) (CPL 2002)

For TMI-1, the $450,000 estimate from Turkey Point is used as it is in the middle range of the industry estimates identified.

E.6.15.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 15 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$198,188	$910	$199,098	$450,000	-$250,902

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.16 SAMA NUMBER 16: AUTOMATE HPI INJECTION ON LOW PRESSURIZER LEVEL

Providing an automatic signal to initiate HPI on low pressurizer level would improve the reliability of HPI initiation. The current initiation logic will not start HPI until low pressure (1600 psig) is reached in the RCS or high reactor building pressure (4 psig) is registered. This is adequate for LOCAs where the pressure drops with RCS level, but for loss of secondary side heat removal cases where the RCS pressure remains high while the level falls, no automated signal is available. HPI initiation is not a complicated action, but high workloads can divert attention from required tasks and providing an automated response to reduced level would prevent core uncovery in the event that a manual initiation is not performed.

Pressurizer level instrumentation already exists for other purposes and the low level signal could be used as a means to start the HPI system.

E.6.16.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMAs averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

In order to represent this SAMA in the PRA, cutset changes were made to address the impact of automating initiation of the HPI system. This method was chosen given that HPI initiation reliability can easily be modified through the manipulation of existing human failure events. In the TMI-1 model, the relevant basic events include an independent event as well as joint human error events. In this case, automating the initiation of HPI (with human backup) is considered to reduce the failure probability to at least 1.0E-04, which is reflected by changing the failure probability of the independent HEP from 2.18E-03 to 1.0E-04. Because automation of the function basically removes it from the joint human error events, those events are set to 0.0. Any combinations of the remaining actions important to the model are treated in separate events and the development of new combinations is not required. The following table summarizes the model changes that were made:

SAMA 16 - Model Changes

GATE AND / OR BASIC EVENT ID AND DESCRIPTION	DESCRIPTION OF CHANGE
BWHBW1-----HP2OA: OPERATOR FAILS TO INITIATE HPI	The basic event probability was changed from 2.18E-03 to 1.00E-04.
JHHMR1-HBW1HEPOA: MRHMR1-----HMUOA AND BWHBW1-----HP2OA (dependence between failure to initiate HPI and failure to establish a min flow path for the HPI pumps)	The basic event probability was changed from 1.40E-03 to 0.0.
JHHAMHEFHBWHEPOA: JHHAM2-HEF1HEPOA AND BWHBW1-----HP2OA(dependence between failure to initiate HPI, failure to start IA on emergency power, and failure to operate EF-V-30 locally after loss of IA)	The basic event probability was changed from 2.40E-04 to 0.0.
JHHEF1-HBW1HEPOA: EFHEF1_OPERH2HOA AND BWHBW1-----HP2OA (dependence between failure to initiate HPI and failure to locally operate the EFW flow control valves)	The basic event probability was changed from 1.00E-04 to 0.0.
JHHEF3-HBW1HEPOA: EFHEF3_OPERH2HOA AND BWHBW1-----HP2OA (dependence between failure to initiate HPI and failure to locally operate the EFW flow control valves after 2 hour bottle depletion)	The basic event probability was changed from 4.10E-04 to 0.0.
JHHEF8-HBW1HEPOA: EFHEF8_OPERHBVOA AND BWHBW1-----HP2OA (dependence between failure to initiate HPI and failure to close EFW flow control block valve)	The basic event probability was changed from 5.70E-05 to 0.0.

The model changes identified above yielded a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk, as summarized below:

SAMA 16 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	2.24E-05	24.27	$78,253
Percent Change	-5.5%	-25.6%	-30.3%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 16 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
$Freq.(/yr)_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
$Freq. (/yr)_{SAMA}$	4.55E-07	8.66E-07	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	6.93E-08	1.64E-07	2.13E-08
$Dose\text{-}Risk_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
$Dose\text{-}Risk_{SAMA}$	2.60	4.95	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	0.43	1.01	0.06
$OECR_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
$OECR_{SAMA}$	$12,649	$24,075	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$1,400	$3,313	$201

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
$Freq.(/yr)_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
$Freq. (/yr)_{SAMA}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.17E-07	2.69E-09	7.44E-07	2.89E-07	3.15E-06	1.34E-05	4.40E-09	2.34E-06	1.89E-08	2.24E-05
$Dose\text{-}Risk_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
$Dose\text{-}Risk_{SAMA}$	0.00	0.00	0.22	0.04	0.29	0.00	1.00	0.39	6.99	3.58	0.00	0.62	0.01	24.27
$OECR_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
$OECR_{SAMA}$	$2	$0	$756	$135	$829	$10	$2,842	$1,104	$19,782	$3,509	$1	$613	$5	$78,253

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 16 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$2,476,374	$795,337	2.0	$1,590,674

E.6.16.2 EXTERNAL FLOODING EVALUATION

This SAMA is of importance primarily in loss of secondary side heat removal cases where low level can occur in the primary side without an RCS low pressure signal. For the external flooding cases, the three flood regimes are impacted differently:

- Floods over 310' msl: In these scenarios, all safety equipment is flooded and this SAMA has no impact on the risk.
- Floods between 305' and 310' msl: Most of the sequences are not impacted by this SAMA as core damage is caused by failure of the flood gates (the SBO EDG is flooded) or because a flood warning is not provided and no preparations are made for the flood (the SBO EDG is flooded). Flood sequence "E" represents cases where the flood gates are correctly installed, but a loss of onsite power leads to core damage. In these cases, an SBO will occur that will lead to seal damage, the majority of which will be of the larger size leaks. For these leaks, loss of inventory through the break will eventually result in a low pressure signal and an automatic HPI initiation if power is recovered. No benefit is considered available for these cases.
- Floods below 305' mls: The only impact these flood scenarios have on the plant is the potential to cause a loss of offsite power. For this evaluation, it is assumed that these sequences are impacted in the same manner as the internal events sequences, which are primarily loss of secondary side heat removal cases. The CDF for this flood sequence is reduced by the same percent as the internal events CDF based on SAMA 16 implementation.

The following tables summarize the results of these changes on external flooding risk:

SAMA 16 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	8.10E-05	177.14	$542,092
Percent Change	0.0%	0.0%	0.0%

A further breakdown of this information is provided below according to release category.

SAMA 16 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' sequence A	305' to 310' sequence B	305' to 310' sequence C	305' to 310' sequence D	305' to 310' sequence E	305' to 310' sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.36E-07	8.10E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.35	177.14
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,152	$542,092

The external flooding component of the averted cost-risk for this SAMA is summarized below:

SAMA 16 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$15,541,516	$1,957

E.6.16.3 COST OF IMPLEMENTATION

The cost of this enhancement was estimated to be $1,100,000 by the TMI staff (Exelon 2007c).

E.6.16.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 16 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$1,590,674	$1,957	$1,592,631	$1,100,000	$492,631

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive.

E.6.17 SAMA NUMBER 17: AUTO ISOLATE STEAM GENERATORS ON HIGH STEAM LINE FLOW

For steam line breaks downstream of the MSIVs, failure to isolate the relevant steam generator is an important contributor to core damage. The addition of logic to isolate the steam generator on high steam line flow would reduce the core damage contribution from isolation failures. The steam line break contributors for TMI typically include multiple operator actions such that further procedure changes to direct mitigation of the event will have a limited impact due to operator dependence issues. The most effective solution was considered to be automation of a mitigating function. For the steam line break contributors, auto isolation of the MSIV was a straightforward change with the potential to impact a majority of the postulated scenarios.

E.6.17.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMAs averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

To simulate the automatic isolation of steam generators during a steamline break scenario, the HEP event SIHSI1-----HSGOA was reduced by a factor of 10 and any associated JHEP events set to 0.0 using previously generated cutsets. The new cutset probabilities for CDF and the various release categories were then summed and used to determine an estimate for the averted cost risk. Therefore, no new logic changes were made to the PRA model and no fault tree requantifications were performed. The following table summarizes the model changes that were made:

SAMA 17 - Model Changes

GATE AND / OR BASIC EVENT ID AND DESCRIPTION	DESCRIPTION OF CHANGE
SIHSI1-----HSGOA: OPERATOR ERROR TO ISOLATE OTSG (BREAK DOWNSTREAM MSIV)	The basic event probability was changed from 1.50E-02 to 1.50E-03.
JHHSI1-HEF3HEPOA: SIHSI1-----HSGOA AND EFHEF3_OPERH2HOA (dependence between break isolation and failure to locally operate EF-V-30 after 2 hour air bottle depletion)	The basic event probability was changed from 1.50E-02 to 0.0.

The model changes identified above yielded a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk, as summarized below:

SAMA 17 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	2.34E-05	32.37	$111,518
Percent Change	-1.3%	-0.7%	-0.7%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 17 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.57E-07	1.58E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.24E-07	1.65E-07	2.19E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.61	9.04	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.45	1.01	0.06
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$12,705	$43,924	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,625	$3,333	$207

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.23E-07	2.75E-09	7.45E-07	2.89E-07	3.18E-06	1.30E-05	1.68E-08	2.35E-06	1.91E-08	2.34E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.06	3.46	0.00	0.63	0.01	32.37
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$2	$0	$756	$135	$852	$11	$2,846	$1,104	$19,970	$3,395	$4	$616	$5	$111,518

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 17 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$3,245,717	$25,994	2.0	$51,988

E.6.17.2 EXTERNAL FLOODING EVALUATION

This SAMA does not have an impact on external flooding given that it impacts only steam line break initiating events. For the external flooding cases, this is not an issue as the reactor is tripped by a manual shutdown (or a LOOP) rather than a steam line break event. No measurable risk reduction is believed to result from implementation of this SAMA for external flooding, as shown below:

SAMA 17 - External Flooding Results

	CDF (/YR)	DOSE-RISK (PERSON-REM/YR)	OECR ($/YR)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	8.11E-05	177.16	$542,159
Percent Change	0.0%	0.0%	0.0%

A further breakdown of this information is provided below according to release category.

SAMA 17 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' sequence A	305' to 310' sequence B	305' to 310' sequence C	305' to 310' sequence D	305' to 310' sequence E	305' to 310' sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159

The external flooding component of the averted cost-risk for this SAMA is, therefore, $0:

SAMA 17 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$15,543,473	$0

E.6.17.3 COST OF IMPLEMENTATION

This SAMA is considered to be similar in scope to SAMA 13 and the same cost of implementation ($950,000) is used for this SAMA.

E.6.17.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 17 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$51,988	$0	$51,988	$950,000	-$898,012

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.18 SAMA NUMBER 18: PROVIDE THE CAPABILITY TO ALIGN THE STANDBY BATTERY CHARGER AND THE 1A/1B DC CROSS-TIE FROM THE MCR

TMI has a spare 125V DC battery charger for each division that can be aligned to either battery bank within a division in the event that a normally operating battery charger fails. Currently, the alignment requires local actions. There is typically adequate time to align the charger in the event of a failure given that the batteries will last at least four hours, but additional changes could be made to allow rapid alignment of the spare charger from the MCR to reduce the manipulation time and improve the man-machine interface.

A divisional cross-tie exists that can be used to tie the DC buses together, if required. Providing the capability to remotely operate the cross-tie would provide an additional means of maintaining DC power to required loads.

E.6.18.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMAs averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

To simulate alignment of a spare battery charger from the MCR, the HEP event DABATTCHGR-HBCOA, which assumed manipulations performed outside the MCR, was lowered by a factor of 10. There were no applicable JHEP events; therefore, no additional basic event data changes were required.

No changes were made to the cutsets to explicitly represent the improvements to the cross-division DC cross-tie, but not modeling this capability does not have a meaningful impact on the results for the following reasons:

- The baseline model does not credit the existing, proceduralized action to cross-tie the DC buses. Given that there is ample time to perform the cross-tie, the base model over-emphasizes the importance of the DC power supplies.
- The HEP representing alignment of the spare battery chargers (DABATTCHGR-HBCOA) is currently assigned a screening value of 0.1. Like the DC cross-tie, spare battery charger alignment is proceduralized and ample time is available for completing the action. If reasonable credit was assigned to DABATTCHGR-HBCOA, the importance of the DC power supplies would be reduced.
- Even with the low credit for DABATTCHGR-HBCOA, the RRW for the action is only 1.001 when SAMA 18 is implemented. This implies that further reductions to the DC power supplied would provide limited benefit.

As a result, the changes made to HEP DABATTCHGR-HBCOA are considered to provide a reasonable assessment of the benefits related to SAMA 18. The following table summarizes the changes that were made to the cutsets:

SAMA 18 - Model Changes

GATE AND / OR BASIC EVENT ID AND DESCRIPTION	DESCRIPTION OF CHANGE
DABATTCHGR-HBCOA:	The basic event probability was changed from 1.00E-01 to 1.00E-02.

The model changes identified above yielded a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk, as summarized below:

SAMA 18 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	2.33E-05	32.54	$112,239
Percent Change	-1.7%	-0.2%	-0.0%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 18 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.57E-07	1.59E-06	1.81E-07	1.24E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.64E-08	1.35E-08	8.54E-09	2.87E-07	7.25E-07	1.65E-07	2.19E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.84	4.46	1.01	0.06
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$12,705	$44,202	$3,367	$231	$3	$3	$7	$11	$327	$121	$77	$2,580	$14,645	$3,333	$207

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.36E-10	2.08E-11	8.00E-08	2.79E-08	2.88E-07	5.41E-09	7.86E-07	3.71E-07	3.17E-06	1.25E-05	1.69E-08	2.55E-06	1.91E-08	2.33E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.22	0.08	0.39	0.01	1.06	0.50	7.04	3.33	0.00	0.68	0.01	32.54
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$2	$0	$756	$264	$1,100	$21	$3,003	$1,417	$19,908	$3,272	$4	$668	$5	$112,239

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 18 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$3,259,138	$12,573	2.0	$25,146

E.6.18.2 EXTERNAL FLOODING EVALUATION

This SAMA is potentially of importance in any event where power to the battery chargers is available. For the external flooding cases, the only two potential sequences that could be impacted by SAMA 18 are:

- Floods between 305’ and 310’ msl, sequence E: Most of the sequences in the 305’ to 310’ msl range are not impacted by this SAMA as core damage is caused by failure of the flood gates (all safety equipment is flooded) or because a flood warning is not provided and no preparations are made for the flood (all safety equipment is flooded). Flood sequence “E” represents cases where the flood gates are correctly installed, but a loss of onsite power leads to core damage. This SAMA would provide benefit for flood sequence “E” when 1) battery depletion is the eventual cause of onsite power failure and alignment of the standby charger would prevent loss of DC power, and 2) when offsite AC power is recovered after loss of all on-site AC power and alignment of the standby charger would restore DC power. For this evaluation, the characteristics of the SBO contributors in flooding sequence “E” are assumed to be the same as the internal events SBO contributors. This is considered to be reasonable given that the flood gates prevent damage to plant safety equipment and offsite power recovery is a minor contributor to the internal events SBO evolutions (implies the potentially longer offsite AC recovery times for flood events are not a factor).
- Floods below 305’ mls: The only impact these flood scenarios have on the plant is the potential to cause a loss of offsite power. For LOOP cases, improved DC reliability can impact the CDF.

As mentioned above, there is some potential for this SAMA to provide a benefit in the flood induced SBO scenarios (flood sequence “E”), but the circumstances in which the SAMA could be used are rare and it will provide an extremely limited benefit.

To investigate this further, the SBO sequences from the base model were quantified and the resulting cutsets were reviewed to determine the contribution of manual alignment of the spare battery chargers. The sequences quantified included those in which AC power was both recovered and not recovered, specifically:

- LOOP-055
- LOOP-057

- LOOP-058
- LOOP-059
- LOOP-062
- LOOP-064
- LOOP-066
- LOOP-067
- LOOP-068
- LOOP-069

Basic event “DABATTCHGR-HBCOA” accounted for only 0.8 percent of the SBO CDF, which implies that of all SBO cases, only 0.8 percent of the contribution includes conditions in which SAMA 18 could provide any benefit. Assuming that SAMA 18 can remove all of the 0.8 percent of the risk attributed to manual battery charger alignment failures results in a 0.8 percent reduction of 305’ to 310’ flood sequence E CDF.

For external floods below 305’ mls, the impact could be larger than for SBO scenarios given that that the need to recover or retain some form of AC power is not a precondition for credit (AC power is already available to the chargers). In these cases, the CDF is considered to behave more like the overall internal events model rather than the SBO subset of the CDF. To represent this behavior, the CDF for external floods below 305’ msl is reduced in proportion to the internal events model based on SAMA 18 implementation.

The results of these processes are summarized below:

SAMA 18 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	8.10E-05	177.06	$541,876
Percent Change	0.0%	0.1%	0.1%

A further breakdown of this information is provided below according to release category.

SAMA 18 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' sequence A	305' to 310' sequence B	305' to 310' sequence C	305' to 310' sequence D	305' to 310' sequence E	305' to 310' sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.63E-06	8.65E-08	2.46E-07	8.10E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.62	0.25	0.36	177.06
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,596	$778	$1,1198	$541,876

The external flooding component of the averted cost-risk for this SAMA is summarized below:

SAMA 18 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$15,535,359	$8,114

E.6.18.3 COST OF IMPLEMENTATION

No plant specific implementation cost was developed for this SAMA. Based on the low impact of the SAMA, the $100,000 minimum cost of a hardware modification (Exelon 2003) is used as the implementation cost.

E.6.18.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 18 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$25,146	$8,114	$33,260	$100,000	-$66,740

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.19 SAMA NUMBER 19: INSTALL BATTERY BACKED HYDROGEN IGNITORS OR A PASSIVE HYDROGEN IGNITION SYSTEM

The addition of hydrogen igniters would provide a means of preventing catastrophic combustible gas burns, which may lead to containment failure, by continuously burning these gases before they reach critical levels. Providing battery backup power would increase the likelihood that this system would be available in LOOP events. Use of a passive system would also function in LOOP as well as long term SBO scenarios.

E.6.19.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMAs averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

To simulate installation of hydrogen ignitors, a new basic event (SAMA19-H2IGNITER) was created to simulate the installation of a proposed hydrogen ignition system to minimize the concentration of hydrogen buildup within containment from various hydrogen producing mechanisms, such as corium-concrete interaction. Addition of this basic event to the Level 2 model necessitated inserting a new level of logic above the existing gate H2BURNS. Specifically, a new AND gate named H2BURNS-1 was inserted as an input to the Containment Event Tree nodal top event EARLY. The two inputs to gate H2BURNS-1 are gate H2BURNS and the new basic event SAMA19-H2IGNITER, with an assumed unavailability of 1.0E-02. This estimate is based on estimating an overall unavailability of a proposed system without identifying any particular design features or support dependencies (consistent with a passive design or an independent battery support system), and also represents a number that is not overly conservative or one that would tend to exaggerate the success of such a proposed system.

In addition, hydrogen burns are potential contributors to containment late; however, review of the cutsets shows that these evolutions are probabilistically insignificant (no cutsets exist that include late containment failure cause by hydrogen burns). All accident sequences including late hydrogen burns result in an intact containment and hydrogen igniters would not impact the results. Consequently, no model changes were included in this quantification to address late hydrogen burns to simplify the modeling process.

The model changes identified above yielded a reduction in the Dose-risk and Offsite Economic cost-risk, but did not impact the CDF, as summarized below:

SAMA 19 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	2.37E-05	29.11	$100,376
Percent Change	0.0%	-10.7%	-10.6%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 19 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	1.76E-07	1.33E-07	2.20E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	1.08	0.82	0.06
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$3,555	$2,687	$208

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.38E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.69	0.00	0.63	0.01	29.11
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,617	$4	$618	$5	$100,376

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 19 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$2,987,716	$283,995	2.0	$567,990

E.6.19.2 EXTERNAL FLOODING EVALUATION

This SAMA can impact many of the external flooding evolutions given that a passive hydrogen ignition system could be available even in extreme flooding conditions. The circumstances related to each flood range are discussed below:

- Floods over 310' msl: For these floods, water level increases until it pours over the top of the existing flood barriers. Once core damage has occurred, the containment response is similar to an SBO scenario where water is not on the containment floor. The early containment failure frequency is assumed to be reduced in proportion to the early containment failures of the internal events model for this SAMA.

- Floods between 305' and 310' msl: Scenarios "A" through "D" are the result of flood gate failures. In these scenarios, no credit would be available for those cases where containment isolation was successfully performed (containment isolation failure will remain as containment isolation failures). In scenarios "A" and "C", cold shutdown is achieved and containment isolation is successful, therefore credit is taken for these cases. For sequences "B" and "D", no credit can be taken for hydrogen ignitors as these sequences represent cases where transition to cold shutdown has not occurred and the containment is not isolated. In sequence "E", the flood gates hold, but EDG failures cause an SBO and prevent a transition to cold shutdown, which results in containment isolation failure and no credit is taken for SAMA 19. For sequence "F", the operators have no warning of the impending flood and the plant is also not transitioned to cold shutdown before flood damage occurs, which implies containment isolation failure and no credit for SAMA 19.

- Floods below 305' mls: These are similar to internal events LOOP scenarios and early containment failures are assumed to be reduced in proportion to those in the internal events model.

Based on the qualitative descriptions above, the following quantitative structure was developed to represent the implementation of this SAMA:

External Flood Sequence Identifier	Quantification Method
>310 Feet	Reduce the "EARLY" release category (RC5) frequency contribution by the same fraction that this SAMA reduced the internal events RC5 frequency. Increase the "Late-SM" release category (RC7) frequency by the amount this SAMA reduced the RC5 frequency to simulate the shift of the release from RC group 5 to RC group 7.
305 to 310 feet Sequence "A"	Reduce the "EARLY" release category (RC5) frequency contribution by the same fraction that this SAMA reduced the internal events RC5 frequency. Increase the "Late-SM" release category (RC7) frequency by the amount this SAMA reduced the RC5 frequency to simulate the shift of the release from RC group 5 to RC group 7.
305 to 310 feet Sequence "B"	No change is made to this sequence's distribution.
305 to 310 feet Sequence "C"	Reduce the "EARLY" release category (RC5) frequency contribution by the same fraction that this SAMA reduced the internal events RC5 frequency. Increase the "Late-SM" release category (RC7) frequency by the amount this SAMA reduced the RC5 frequency to simulate the shift of the release from RC group 5 to RC group 7.
305 to 310 feet Sequence "D"	No change is made to this sequence's distribution.
305 to 310 feet Sequence "E"	No change is made to this sequence's distribution.
305 to 310 feet Sequence "F"	No change is made to this sequence's distribution.
<305 feet	Reduce the "EARLY" release category (RC5) frequency contribution by the same fraction that this SAMA reduced the internal events RC5 frequency. Increase the "Late-SM" release category (RC7) frequency by the amount this SAMA reduced the RC5 frequency to simulate the shift of the release from RC group 5 to RC group 7.

Due to the relatively large early containment failure component of the external events model, this SAMA has a large impact on the external flooding risk, as summarized below:

SAMA 19 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	8.11E-05	145.71	$434,849
Percent Change	0.0%	-17.8%	-19.8%

A further breakdown of this information is provided below according to release category.

SAMA 19 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' sequence A	305' to 310' sequence B	305' to 310' sequence C	305' to 310' sequence D	305' to 310' sequence E	305' to 310' sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	104.56	10.34	0.19	1.49	17.87	10.71	0.25	0.30	145.71
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$309,750	$30,635	$598	$4,401	$54,839	$32,858	$778	$991	$434,849

The corresponding external flooding component of the averted cost-risk is shown below:

SAMA 19 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$12,983,587	$2,559,886

E.6.19.3 COST OF IMPLEMENTATION

The cost of this enhancement was estimated to be $760,000 in the Calvert Cliffs SAMA analysis (BGE 1998).

E.6.19.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 19 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$567,990	$2,559,886	$3,127,876	$760,000	$2,367,876

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive.

E.6.20 SAMA NUMBER 20: EXTEND THE HIGH PRESSURE BOUNDARY THROUGH DHR VALVE DH-V-3 FOR ISLOCA ISOLATION

The highest frequency ISLOCA core damage scenario for TMI-1 is through two valves in the DHR suction line. While the frequency is relatively low in terms of CDF, the release frequency is relatively high given that primary containment is bypassed by definition. No effective mitigating actions are considered to be available in these cases because 1) the break may occur upstream of DH-V-3 or additional breaks in the low pressure boundary may occur after closure of a low pressure isolation valve, 2) reduction of primary system pressure may reduce the flow out of the break, but it would not stop it, and 3) refill of the BWST does not place the plant in a stable state and the impacts of auxiliary building flooding would have to be addressed before a successful endstate could be assigned to this type of action. Extending the pressure boundary through DH-V-3 would provide an additional isolation point in these cases.

This SAMA would provide an effective means of terminating the ISLOCA event and the reliability would be limited primarily by the ability of the operators to diagnose the event. Maintaining DH-V-3 as a motor operated valve will ensure that the break can be isolated quickly and without exposing the operators to potentially hazardous conditions.

E.6.20.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of SAMA 20’s averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

In order to represent this SAMA in the PRA, cutset changes were made to address the impact of extending the high pressure boundary of the DHR suction line. This method was chosen given that ISLOCA events are modeled in a single cutset and are easily manipulated within the cutsets. While the lumped event includes more than one ISLOCA contributor, most of the risk is due to the DHR suction line scenario, so it is assumed that manipulation of the ISLOCA cutset can be used to represent changes to the DHR suction line scenario frequency. For the purposes of this analysis, implementation of this SAMA is assumed to eliminate ISLOCA risk completely. The following table summarizes the changes that were made to the cutsets:

SAMA 20 - Cutset Changes

GATE AND / OR BASIC EVENT ID AND DESCRIPTION	DESCRIPTION OF CHANGE
%ISL: INTERFACING SYSTEM LOCA	The initiating event probability was changed from 1.80E-07 to 0.0.

The change identified above yielded a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk, as summarized below:

SAMA 20 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	2.35E-05	31.65	$108,733
Percent Change	-0.8%	-2.9%	-3.1%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 20 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.57E-07	1.59E-06	6.31E-10	3.66E-09	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.61	9.09	0.00	0.02	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$12,705	$44,202	$12	$68	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.35E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.52	0.00	0.63	0.01	31.65
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,459	$4	$618	$5	$108,733

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 20 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$3,184,724	$86,987	2.0	$173,974

E.6.20.2 EXTERNAL FLOODING EVALUATION

This SAMA does not have an impact on external flooding given that it impacts only ISLOCA events and dual of importance in SGTR events where RCS inventory leaves the containment and is unavailable for recirculation from the sump. For the external flooding cases, this is not an issue as the reactor is tripped by a manual shutdown (or LOOP) rather than an ISLOCA event. While LOCAs are likely in external flooding scenarios due to SBO induced seal LOCAs, the sump would be available if AC power was subsequently recovered. No measurable risk reduction is believed to result from implementation of this SAMA for external flooding, as summarized below:

SAMA 20 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	8.11E-05	177.16	$542,159
Percent Change	0.0%	0.0%	0.0%

A further breakdown of this information is provided below according to release category.

SAMA 20 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' sequence A	305' to 310' sequence B	305' to 310' sequence C	305' to 310' sequence D	305' to 310' sequence E	305' to 310' sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
Base Dose-Risk	1.33E+02	1.31E+01	1.90E-01	1.89E+00	1.79E+01	1.07E+01	2.50E-01	3.70E-01	1.77E+02
SAMA Dose-Risk	1.33E+02	1.31E+01	1.90E-01	1.89E+00	1.79E+01	1.07E+01	2.50E-01	3.70E-01	1.77E+02
Base OECR	4.06E+05	4.01E+04	5.98E+02	5.77E+03	5.48E+04	3.29E+04	7.78E+02	1.22E+03	$542,159
SAMA OECR	4.06E+05	4.01E+04	5.98E+02	5.77E+03	5.48E+04	3.29E+04	7.78E+02	1.22E+03	$542,159

The external flooding component of the averted cost-risk for this SAMA is, therefore, $0:

SAMA 20 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$15,543,473	$0

E.6.20.3 COST OF IMPLEMENTATION

The cost of this enhancement was estimated to be $3,030,000 by the TMI staff (Exelon 2007c).

E.6.20.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 20 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$173,974	$0	$173,974	$3,030,000	-$2,856,026

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.21 SAMA NUMBER 21: INSTALL CONCRETE SHIELDS TO BLOCK DIRECT PATHWAYS FROM THE RPV TO THE CONTAINMENT WALL AND/OR DIRECT CONTAINMENT FLOODING EARLY IN EXTERNAL FLOODING SCENARIOS

This SAMA is based on a failure mode identified in the Level 2 analysis that indicates core debris ejection during reactor vessel failure could result in dispersal of debris such that it could directly interact with the containment wall and cause a failure of the wall (early containment failure). Quantitatively, the largest contributor comes from low pressure melt cases where the core debris flows over the containment floor to contact the containment wall. This type of interaction could be prevented through the installation of concrete barriers to contain the core debris away from the outer containment wall.

Another option for this SAMA, which is important for external flooding cases, is to direct flooding of the containment early so that water would be on the floor of the containment before core damage/vessel failure. For internal events evolutions, the SAMGs direct containment flooding when there are indicators of the onset of core damage (e.g., high core temperatures, hydrogen in the reactor building), which adequately addresses the sequences of concern. For external flooding cases, however, the ability to initiate containment sprays will be lost before there are any indicators of core damage such that the existing SAMGs cannot be credited for directing containment flooding.

Both the installation of concrete barriers and the procedure changes for external flooding cases are discussed in more detail in the following subsections.

E.6.21.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component this SAMA's averted cost-risk associated with the internal events and the non-external flooding external events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

In order to represent this SAMA in the PRA, cutset changes were made to address the impact of installing the concrete barriers. This method was chosen given that the containment wall/core debris interaction events are represented by two basic events and can easily be changed. In the TMI-1 model, there is a low pressure melt case (CWNOLIMITLPME) and a high pressure melt case (CWNOLIMITHPME). The low pressure melt case is by far the more significant contributor of the two to the early containment failure frequency. The high pressure melt case, while already a low contributor, is linked to the failure to locally operate the ADVs, which is currently assigned a value of 1.0. Procedures exist at TMI-1 to operate the ADVs locally, but the model does not currently credit the procedures. As a result, the importance of CWNOLIMITHPME is artificially inflated. CWNOLIMITHPME could be excluded from consideration in this SAMA, but for completeness, both CWNOLIMITHPME and CWNOLIMITLPME are included in the modeling changes.

While this SAMA does reduce the early containment failure frequency, it does not necessarily eliminate the release and it must be re-distributed to prevent over crediting this SAMA. The concrete barrier will prevent core debris attack on the containment wall, but basemat failure could still occur depending on the availability of water on the containment floor and the coolability of the core debris. Based on a review of the cutsets containing events CWNOLIMITLPME and CWNOLIMITHPME, containment spray is available about 50 percent of the time. For the cases where it is not available, basemat failure is assumed. When containment spray is available, the debris is assumed to be coolable only 50 percent of the time, which is consistent with the TMI-1 Level 2 analysis. When spray is containment spray is available and the debris is coolable, it is assumed that containment heat removal is available and that these cases result in an intact containment (RC group 9) rather than a late overpressurization failure (RC group 7). The following table summarizes the model changes that were made:

SAMA 21 - Model Changes

GATE AND / OR BASIC EVENT ID AND DESCRIPTION	DESCRIPTION OF CHANGE
CWNOLIMITLPME: Plant Config and Layout Does Not Limit Material Reaching Cont. Wall With LPM	The basic event probability was changed from 1.00E-01 to 0.0 to account for the ability of the concrete barriers to prevent failure of the containment wall.
CWNOLIMITHPME: Plant Config and Layout Does Not Limit Material Reaching Cont. Wall With HPM	The basic event probability was changed from 1.00E-01 to 0.0 to account for the ability of the concrete barriers to prevent failure of the containment wall.
RC8 (Basemat failure) Frequency	Increase the frequency by 75 percent of the reduction in RC5 (Early containment failure). This accounts for both the cases in which containment spray is not available and those cases where containment spray is available, but the debris is not coolable. (0.5 * RC5 reduction + 0.5 * RC5 reduction * 0.5 = 0.75 * RC5 reduction)
RC9 (Intact) Frequency	Increase the frequency by 25 percent of the reduction in RC5 (Early containment failure). This accounts for the cases in which containment spray is available and the core debris is coolable. (0.5 * RC5 reduction * 0.5 = 0.25 * RC5 reduction)

The model changes identified above yielded no change in the CDF, but did reduce the Dose-risk and Offsite Economic cost-risk, as summarized below:

SAMA 21 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	2.37E-05	31.5	$108,333
Percent Change	0.0%	-3.4%	-3.5%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 21 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	5.94E-07	5.65E-08	2.20E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	3.65	0.35	0.06
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$11,999	$1,141	$208

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.38E-06	1.32E-05	8.05E-08	2.36E-06	1.91E-08	2.37E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.51	3.53	0.02	0.63	0.01	31.50
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$21,232	$3,461	$21	$618	$5	$108,333

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 21 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$3,179,284	$92,427	2.0	$184,854

E.6.21.2 EXTERNAL FLOODING EVALUATION

The typical external flooding evolution is one in which the plant is stable until flood waters breach the flood gates and fail safety equipment. Alone, the concrete barriers would shift containment failure and the corresponding release from the “Early” release category (RC group 5) to the “basemat failure” category (RC group 8), assuming the containment is isolated. Flooding the containment floor can prevent core/concrete attack 50 percent of the time and in conjunction with the concrete barriers, the containment failure mode would be a long term overpressurization failure with a release that would be categorizes as “Late-small” (RC group 8). For the internal events model, an “intact” containment state was assumed to be possible given the potential for heat removal to be available, but for the external flooding cases, heat removal is not assumed to be available due to SBO conditions and a late overpressurization failure is considered to be more appropriate. For the 50 percent of the cases in which core-concrete attack is not prevented, basemat failure is assumed (RC group 8).

For many flood sequences, the loss of AC power will not be anticipated in time to initiate containment flooding, but in some cases, changes in the procedures could allow containment flooding as a means of reducing the release severity:

- Floods over 310’ msl: For these floods, water level increases until it pours over the top of the existing flood barriers. In these evolutions, there would likely be an interval when water level is rising between 305’ and 310’ msl when the determination could be made that the flood water will eventually top the barriers and that containment flooding should be performed as a precaution. Given that the flood gates are available and can be used to maintain the core in a safe state without risking further damage to the plant, flooding the containment floor to a depth where the water would remain available until vessel breach would be undesirable until absolutely necessary. While this is true, it is a credible means of reducing the probability of early containment failure and basemat failures. Containment spray is assumed to always be available before flood gate topping such that containment flooding will be successful, if directed.

- Floods between 305’ and 310’ msl: Scenarios “A” through “D” are the result of flood gate failures. In these scenarios, no credit would be available for performing early containment spray as core damage would not be anticipated and there would be no desirable cue to direct containment flooding. In scenarios “A” and “C”, credit could be taken for the concrete barriers as cold shutdown is achieved (implies containment isolation) and the barriers would prevent interaction with the containment wall. For sequences “B” and “D”, no credit can be taken for the concrete barriers as these sequences represent cases where transition to cold shutdown has not occurred and the containment is not isolated (these remain containment isolation failure cases). In sequence “E”, the flood gates hold, but EDG failures cause an SBO and no credit would be available for containment spray. Due to the AC power failures, the plant was not transitioned to cold shutdown and a containment isolation failure would occur (no credit for concrete barriers). For sequence “F”, the operators have no warning of the impending flood and the plant is also not transitioned to cold shutdown before flood damage occurs, which implies containment isolation failure.

- Floods below 305' mls: These are similar to LOOP scenarios and containment flooding is already addressed by the SAMGs. These cases are treated in the same manner as the internal events cases.

Based on the qualitative descriptions above, the following quantitative structure was developed to represent the implementation of this SAMA:

External Flood Sequence Identifier	Quantification Method
>310 Feet	• Reduce the "EARLY" release category (RC group 5) frequency contribution by the same fraction that this SAMA reduced the internal events RC group 5 frequency. • Increase the basemat failure frequency (RC group 8) by 50 percent of the reduction in RC group 5. This accounts for the cases where containment spray is available, but the debris is not coolable. Containment spray is assumed to always be available before topping of the flood gates. (0.5 * RC5 reduction) • Increase the late containment failure frequency (RC group 7) by 50 percent of the reduction in RC group 5. This accounts for the cases in which containment spray is available, the core debris is coolable, and lack of heat removal results in late containment failure. Containment spray is assumed to always be available before topping of the flood gates. (0.5 * RC5 reduction)
305 to 310 feet Sequence "A"	Reduce the "EARLY" release category (RC group 5) frequency contribution by the same fraction that this SAMA reduced the internal events RC5 frequency. Increase the "Basemat Failure" release category (RC8) frequency by the amount this SAMA reduced the RC5 frequency to simulate the shift of the release from RC group 5 to RC group 8.
305 to 310 feet Sequence "B"	No change is made to this sequence's distribution.
305 to 310 feet Sequence "C"	Reduce the "EARLY" release category (RC5) frequency contribution by the same fraction that this SAMA reduced the internal events RC5 frequency. Increase the "Basemat Failure" release category (RC8) frequency by the amount this SAMA reduced the RC5 frequency to simulate the shift of the release from RC group 5 to RC group 8.
305 to 310 feet Sequence "D"	No change is made to this sequence's distribution.
305 to 310 feet Sequence "E"	No change is made to this sequence's distribution.
305 to 310 feet Sequence "F"	No change is made to this sequence's distribution.
<305 feet	Treated in the same manner as the internal events model.

Due to the relatively large early containment failure component of the external events model, this SAMA has a large impact on the external flooding risk, as summarized below:

SAMA 21 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	8.11E-05	165.06	$500,115
Percent Change	0.0%	-6.8%	-7.8%

A further breakdown of this information is provided below according to release category.

SAMA 21 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' sequence A	305' to 310' sequence B	305' to 310' sequence C	305' to 310' sequence D	305' to 310' sequence E	305' to 310' sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	121.80	12.15	0.19	1.75	17.87	10.71	0.25	0.34	165.06
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$367,957	$36,696	$598	$5,271	$54,839	$32,858	$778	$1,118	$500,115

The external flooding component of the averted cost-risk is summarized below:

SAMA 21 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$14,547,190	$1,181,137

E.6.21.3 COST OF IMPLEMENTATION

The cost of implementation is estimated to be $1,200,000 by the TMI staff (Exelon 2007c).

E.6.21.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 21 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$184,854	$996,283	$1,181,137	$1,200,000	-$18,863

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.22 SAMA NUMBER 22: INSTALL AN INDEPENDENT EFW SYSTEM

For TMI-1, loss of MFW after a trip coupled with loss of EFW can lead to large radionuclide releases in SGTR and induced SGTR scenarios due to the unavailability of water in the SGs for fission product scrubbing. A large contributor to EFW failure is estimated to be system wide common cause failures. An independent, motor driven, auxiliary feedwater system would be an effective means of addressing these cases. Power dependence is not a large issue for the cases addressed by this SAMA and the independent EFW pump is assumed to be powered by existing emergency power such that it would not be capable of mitigating SBO scenarios.

E.6.22.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMAs averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

New simplified model logic was added to the PRA model to represent an independent system that provides a backup to the existing EFW system. Requantification of the PRA model was then performed to determine new core damage and release category frequencies.

Specifically, for non-ATWS scenarios, a new level of logic was added above the gate EFNOATWS (EFW without ATWS conditions) consisting of a new AND gate named EFNOATWS-1 with two inputs. The two inputs to this new gate consisted of the original logic gate EFNOATWS and a new OR gate named ALT-EFW-NOATWS (failure of alternate EFW for non-ATWS conditions). The inputs to the OR gate
ALT-EFW-NOATWS consisted of the following inputs:

SAMA 22 NON-ATWS BASIC EVENTS	UNAVAILABILITY	EVENT DESCRIPTION
SAMA22ELECNOATWS	1.00E-02	NON-ATWS ALTERNATE EFW ELECTRICAL POWER DEPENDENCY FAILURES
SAMA22MECHNOATWS	1.00E-03	NON-ATWS ALTERNATE EFW MECHANICAL DEPENDENCY FAILURES
SAMA22HEP-NOATWS	1.00E-01	NON-ATWS ALTERNATE EFW HEP FAILURES
SAMA22JHEPNOATWS	5.00E-02	NON-ATWS ALTERNATE EFW JHEP FAILURES

The electrical event unavailability was based on the assumption that electrical dependencies require several other dependencies and control signals to function properly, thus resulting in a higher unavailability relative to assumed mechanical failures. The mechanical unavailability event was arbitrarily represented as 0.001, since most mechanical failures are typically of this order of magnitude. The independent HEP event was arbitrarily assigned an unavailability of 0.1, since this was based on the assumption that several actions would need to be performed outside the MCR. The JHEP event was estimated as having a high dependence for failure of a second related event, meaning that failure of the second HEP event was highly dependent on failure of the HEP event SAMA22HEP-NOATWS.

For ATWS scenarios, the fault tree logic for gate EFATWS was modified in the same manner as described above. In addition, the unavailabilities for the added basic events discussed above were increased by a factor of 3 (half a decade based on a logarithmic scale) to account for ATWS environmental stress factors and a greater sense of urgency. These events are identified in the table below:

SAMA 22 ATWS BASIC EVENTS	UNAVAILABILITY	EVENT DESCRIPTION
SAMA22ELEC--ATWS	3.00E-02	ATWS ALTERNATE EFW ELECTRICAL POWER DEPENDENCY FAILURES
SAMA22MECH--ATWS	3.00E-03	ATWS ALTERNATE EFW MECHANICAL POWER DEPENDENCY FAILURES
SAMA22HEP---ATWS	3.00E-01	ATWS ALTERNATE EFW HEP FAILURES
SAMA22JHEP--ATWS	1.50E-01	ATWS ALTERNATE EFW JHEP FAILURES

All affected logic described above that is modeled within the logic structure for post-LOOP recovery scenarios was also modified, with applicable gate names appended with the characters “-R”. This was only necessary for the logic involving non-ATWS scenarios.

The model changes identified above yielded a reduction in the Dose-risk and Offsite Economic cost-risk, but did not impact the CDF, as summarized below:

SAMA 22 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	2.22E-05	27.05	$85,423
Percent Change	-6.3%	-17.0%	-23.9%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 22 Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.21E-07	6.49E-07	1.80E-07	9.45E-09	9.07E-11	9.07E-11	1.90E-10	3.46E-10	3.81E-08	2.43E-08	8.54E-09	5.12E-07	6.88E-07	1.70E-07	2.14E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.41	3.71	0.91	0.05	0.00	0.00	0.00	0.00	0.11	0.07	0.03	1.50	4.23	1.05	0.06
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$11,704	$18,042	$3,348	$176	$3	$3	$7	$13	$343	$218	$77	$4,603	$13,898	$3,434	$202

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.72E-10	0.00E+00	8.02E-08	1.49E-08	2.18E-07	2.86E-09	7.47E-07	2.90E-07	3.14E-06	1.26E-05	2.70E-09	2.34E-06	3.08E-09	2.22E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.23	0.04	0.29	0.00	1.01	0.39	6.97	3.37	0.00	0.62	0.00	27.05
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$3	$0	$758	$141	$833	$11	$2,854	$1,108	$19,719	$3,311	$1	$613	$1	$85,423

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 22 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$2,662,735	$608,976	2.0	$1,217,952

E.6.22.2 EXTERNAL FLOODING EVALUATION

This SAMA will have a limited impact for external flooding scenarios given that many of the scenarios result in flooding the plant's safety equipment, which would render the proposed equipment inoperable. Even if the independent EFW system were located in a flood safe zone, the floods cause an SBO and subsequent seal LOCA that would result in core damage regardless of the operability of an alternate EFW system. The circumstances related to each flood range are discussed below:

- Floods over 310' msl: For these floods, water level increases until it pours over the top of the existing flood barriers. Flooding of safety equipment occurs and the subsequent seal LOCA will lead to core damage with or without SAMA 22. No credit is taken for this SAMA for this flood scenario.

- Floods between 305' and 310' msl: Scenarios "A" through "D" are the result of flood gate failures. In these scenarios, the result is the same as for floods over 310' msl and no credit is taken for SAMA 22. In sequence "E", the flood gates hold, but EDG failures cause an SBO. Alternate EFW could be beneficial if AC power was recovered to provide primary side makeup, but review of the LOOP/SBO model and the baseline SBO cutsets shows that EFW operability is only important to prolonging the time to core damage to allow AC power recovery. For floods of this magnitude, the normal AC power recovery credits are not considered to be applicable and the benefit of delaying core damage for a matter of a couple of hours would be minimal. No credit is taken for this SAMA for sequence "E". For sequence "F", the operators have no warning of the impending flood and the flood gates are not installed in time to prevent flooding of the safety equipment. As with the other, similar sequences, no credit is taken for SAMA 22 for sequence "F".

- Floods below 305' mls: These are similar to internal events LOOP scenarios and the availability of an alternate EFW system would be beneficial. In order to simplify the modeling for this sequence, SAMA 22 is assumed to eliminate all risk from these flood scenarios.

Implementation of this SAMA would result in only a limited risk reduction, as summarized below:

SAMA 22 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	8.08E-05	176.79	$540,940
Percent Change	-0.3%	-0.2%	-0.2%

A further breakdown of this information is provided below according to release category.

SAMA 22 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' sequence A	305' to 310' sequence B	305' to 310' sequence C	305' to 310' sequence D	305' to 310' sequence E	305' to 310' sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	0.00E+00	8.08E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.00	176.79
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$0	$540,940

The corresponding external flooding component of the averted cost-risk is shown below:

SAMA 22 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$15,507,657	$35,816

E.6.22.3 COST OF IMPLEMENTATION

Calvert Cliffs estimated the cost of installing an additional HPSI pump with a dedicated diesel to be between $5 million and $10 million. This type of enhancement is similar is scope to the changes required for this SAMA and the lower bound estimate of $5 million is used for this SAMA as the independent diesel is not required for this SAMA.

E.6.22.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 22 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$1,217,952	$35,816	$1,253,768	$5,000,000	-$3,746,232

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.23 SAMA NUMBER 23: DEVELOP ALARM RESPONSE PROCEDURES TO DIRECT OPERATION OF RR-V-5 ON LOW RBEC FLOW

Failure of RR-V-6 to open results in the loss of RBEC flow to the reactor building coolers, which can be diagnosed using the system flow indicators in the main control room; however, no alarm response procedures exist to specifically direct operation of the bypass valve (RR-V-5). If this procedure was developed, it may reduce the diagnosis time and improve the reliability of this operator action in an accident conditions.

E.6.23.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMAs averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events based averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

To model a more improved procedure regarding loss of RBEC flow from failure of RR-V-6 and recovery via MOV RR-V-5, the HEP event CFHRR1-----HVAOA was reduced by a factor of 10, from 7.79E-01 to 7.79E-02. There were no applicable JHEP events. The new cutset probabilities for the various Level 2 release categories were then summed and used to determine an estimate for the averted cost risk. Therefore, no new logic changes were made to the PRA model and no fault tree requantifications were performed. The following table summarizes the changes that were made to the model:

SAMA 23 - Model Changes

GATE AND / OR BASIC EVENT ID AND DESCRIPTION	DESCRIPTION OF CHANGE
CFHRR1-----HVAOA: OPERATOR FAILS TO OPEN MOV RR-V-5	The basic event probability was changed from 7.79E-1 to 7.79E-02.

The model changes identified above yielded a reduction in the Dose-risk and Offsite Economic cost-risk, but did not impact the CDF, as summarized below:

SAMA 23 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	2.37E-05	32.42	$111,626
Percent Change	0.0%	-0.6%	-0.6%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 23 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	1.36E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.04
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$129

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.36E-10	2.08E-11	7.72E-08	1.43E-08	1.42E-07	2.69E-09	7.13E-07	2.89E-07	3.17E-06	1.34E-05	1.69E-08	2.34E-06	1.91E-08	2.37E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.22	0.04	0.19	0.00	0.96	0.39	7.04	3.57	0.00	0.62	0.01	32.42
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$2	$0	$730	$135	$542	$10	$2,724	$1,104	$19,908	$3,505	$4	$613	$5	$111,626

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 23 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$3,256,480	$15,231	2.0	$30,462

E.6.23.2 EXTERNAL FLOODING EVALUATION

This SAMA will have a limited impact for external flooding scenarios given that many of the scenarios result in flooding the plant's safety equipment, which would render the reactor building coolers inoperable. For cases in which power is available, there would be some benefit. The circumstances related to each flood range are discusses below:

- Floods over 310' msl: For these floods, water level increases until it pours over the top of the existing flood barriers. Flooding of safety equipment occurs and the subsequent damage to the plant would result in a permanent loss of AC power. No credit is taken for this SAMA for this flood scenario.

- Floods between 305' and 310' msl: Scenarios "A" through "D" are the result of flood gate failures. In these scenarios, the result is the same as for floods over 310' msl and no credit is taken for SAMA 23. In sequence "E", the flood gates hold, but EDG failures cause an SBO. This SAMA could be useful if power was recovered and there was a failure of the RR-V-6 valve to open. Given that only 0.7 percent of the internal events SBO contributors are "power recovered" cases (flooding cases are less likely to recover power due to extreme weather), that RR-V-6 failures contribute to less that 2.0 percent to the release frequency even when power is available, and that the total Sequence "E" frequency is only 3.66E-06, the impact of this SAMA would not be measurable. No credit is taken for this SAMA for sequence "E". For sequence "F", the operators have no warning of the impending flood and the flood gates are not installed in time to prevent flooding of the safety equipment. As with the other, similar sequences, no credit is taken for SAMA 23 for sequence "F".

- Floods below 305' mls: These are similar to internal events LOOP scenarios and the recovery of RB cooling could be beneficial. The dose-risk and OECR of this flood sequence are assumed to be reduced in proportion to the internal events dose-risk and OECR.

Implementation of this SAMA would result in only a limited risk reduction, as summarized below:

SAMA 23 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	8.11E-05	177.16	$542,152
Percent Change	0.0%	0.0%	0.0%

A further breakdown of this information is provided below according to release category.

SAMA 23 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' sequence A	305' to 310' sequence B	305' to 310' sequence C	305' to 310' sequence D	305' to 310' sequence E	305' to 310' sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,212	$542,152

The corresponding external flooding component of the averted cost-risk is shown below:

SAMA 23 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$15,543,306	$167

E.6.23.3 COST OF IMPLEMENTATION

Procedure changes are estimated to be $50,000 (CPL 2004).

E.6.23.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 23 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$30,462	$167	$30,629	$50,000	-$19,371

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.24 SAMA NUMBER 24: INSTALL DAMAGE RESISTANT HIGH TEMPERATURE RCP SEALS WITH A DIESEL ENGINE AS AN ALTERNATE DRIVE FOR AN EFW PUMP AND A PORTABLE 480V AC GENERATOR FOR EXTENDED EFW OPERATION

For SBOs in which EFW has failed, neither primary nor secondary side cooling is available. Installing the enhanced RCP seals will prevent seal LOCAs and use of a portable generator would allow the turbine driven EFW pump to be used for extended periods in an SBO, as suggested in SAMA 2. However, in the event that the turbine driven EFW pump fails, there would be no means of providing secondary side makeup. Turbine driven EFW failures could be mitigated if an engine was available to drive one of the EFW pumps. Other industry SAMA applications have suggested similar strategies, but they typically suggest the turbine driven pumps as the best option for connection to the engine based on ease of connection. For scenarios with turbine driven EFW failure, however, the initial TD EFW pump failure may prevent its further use even with an alternate motive source. As a result, this SAMA, in addition to the requirements of SAMA 2, requires that the diesel engine be connected to one of the motor driven EFW pumps.

E.6.24.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMA's averted cost-risk associated with the internal events and the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events based averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

To simulate the availability of a proposed alternate diesel-driven EFW pump, the cutsets from SAMA 2 were further adjusted by setting the turbine-driven EFW pump start and run failures to zero, i.e., EFEF-P-1----P7FS and EFEFP1------P7FR, respectively. Other contributors exist related to turbine driven EFW failures, but these are the major contributors and removing them from the cutsets is considered to adequately represent the benefits this SAMA. The new cutset probabilities for CDF and the various release categories were then summed and used to determine an estimate for the averted cost risk. Therefore, no new logic changes were made to the PRA model and no fault tree requantifications were performed. The following table summarizes the changes that were made to the basic event data:

SAMA 24 - Model Changes

Gate and / or Basic Event ID and Description	Description of Change
EFEF-P-1----P7FS: TURBINE-DRIVEN PUMP EF-P-1 FAILS TO START	The basic event probability was changed from 4.66E-03 to 0.0.
EFEFP1------P7FR: TURBINE-DRIVEN PUMP EF-P-1 FAILS TO RU	The basic event probability was changed from 5.06E-02 to 0.0.

The model changes identified above yielded a reduction in the CDF, Dose-risk, and Offsite Economic cost-risk, as summarized below:

SAMA 24 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	1.11E-05	14.68	$54,017
Percent Change	-53.2%	-55.0%	-51.9%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 24 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.18E-07	8.46E-07	1.80E-07	9.29E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	7.15E-09	1.25E-09	4.86E-11	2.67E-08	3.54E-07	4.88E-08	5.81E-09
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.39	4.84	0.91	0.05	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.08	2.18	0.30	0.02
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$11,620	$23,519	$3,348	$173	$0	$0	$0	$0	$64	$11	$0	$240	$7,151	$986	$55

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.43E-11	0.00E+00	5.24E-09	1.33E-09	6.66E-08	3.81E-10	5.57E-08	3.54E-08	6.34E-07	8.12E-06	4.86E-09	2.81E-07	7.97E-11	1.11E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.01	0.00	0.09	0.00	0.08	0.05	1.41	2.17	0.00	0.08	0.00	14.68
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$0	$0	$50	$13	$254	$1	$213	$135	$3,982	$2,127	$1	$74	$0	$54,017

Based on these results, the averted cost-risk for all non-external flooding contributors can be calculated using the 2.0 multiplier on the internal events results:

SAMA 24 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$1,536,137	$1,735,574	2.0	$3,471,148

E.6.24.2 EXTERNAL FLOODING EVALUATION

This SAMA can have an impact on any SBO, seal LOCA, or EFW failure scenario. For the external flooding cases, the three flood regimes are impacted differently:

- Floods over 310' msl: In these scenarios, all safety equipment is flooded and this SAMA has no impact on the risk. No provisions are made for flood proofing the EFW pump in this SAMA. SAMA 32 addresses flood proof secondary side makeup capabilities.

- Floods between 305' and 310' msl: Most of the sequences are not impacted by this SAMA as core damage is caused by failure of the flood gates (the safety equipment is flooded) or because a flood warning is not provided and no preparations are made for the flood (the safety equipment is flooded). Flood sequence "E" represents cases where the flood gates are correctly installed, but a loss of all AC power leads to core damage. These SBO cases are assumed to be completely mitigated by this SAMA.

- Floods below 305' mls: The only impact these flood scenarios have on the plant is the potential to cause a loss of offsite power. As a result, these flooding sequences would be impacted in the same way as the internal events LOOP events. In order to simplify the calculations, SAMA 24 is assumed to eliminate all risk from this flooding sequence.

The following tables summarize the results of these changes:

SAMA 24 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	7.72E-05	166.08	$508,082
Percent Change	-4.8%	-6.3%	-6.3%

A further breakdown of this information is provided below according to release category.

SAMA 24 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' Sequence A	305' to 310' Sequence B	305' to 310' Sequence C	305' to 310' Sequence D	305' to 310' Sequence E	305' to 310' Sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	0.00E+00	8.65E-08	0.00E+00	7.72E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	132.75	13.13	0.19	1.89	17.87	0.00	0.25	0.00	166.08
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$405,951	$40,149	$598	$5,767	$54,839	$0	$778	$0	$508,082

Based on these results, the external flooding component of the averted cost-risk can then be calculated:

SAMA 24 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$14,598,420	$945,053

E.6.24.3 COST OF IMPLEMENTATION

The cost of implementation for this SAMA is estimated to be a combination of SAMA 2 ($7,300,000) and the $1.1 million estimate for a direct drive diesel injection pump from Palisades (NMC 2005). The total implementation cost is $8,400,000.

E.6.24.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 24 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$3,471,148	$945,053	$4,416,201	$8,400,000	-$3,983,799

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.25 SAMA NUMBER 25: INSTALL AN ADDITIONAL EDG

An additional source of AC power is a potential means of supplying an entire division of safety equipment in the event that on-site AC power is lost in a LOOP. While additional EDGs are expensive, they can be cost effective at some plants, especially those with a large LOOP/SBO contribution to CDF.

However, for TMI-1, the SBO EDG is available at the site and a less costly solution to reducing risk through AC power improvements would be to implement SAMA 1 rather than to install an additional EDG. Without auto alignment capability, the benefit of a new EDG would not be maximized and installing an additional EDG with auto alignment capability would be illogical when the existing SBO EDG could be upgraded first. Therefore, installation of an additional EDG would imply that SAMA 1 must already be installed. In this case, the benefit of installing an additional EDG is approximated assuming previous installation of SAMA 1, but the cost of SAMA 1 is not included in the SAMA 25 implementation cost.

E.6.25.2 NON-EXTERNAL FLOODING EVALUATION

Rather than perform a full scale model change to evaluate this SAMA, PRA insights from the SAMA 1 results can be used to show that adding an additional EDG after implementing SAMA 1 would not be cost effective. The RRW values for the SBO EDG “fail to start”, “fail to run”, and maintenance terms based on both CDF and Level 2 are provided in the table below from the SAMA 1 importance lists. These are the main contributors to SBO EDG failures:

BASIC EVENT	CDF BASED RRW VALUE	LEVEL 2 BASED RRW VALUE
GSEG-Y-4----DGFS: STATION BLACKOUT DG FAILS TO START	1.010	1.025
GS-SBODG----DGFR: SBO DIESEL FAILS TO RUN	1.019	1.049
GS-EG-Y-4---DGMM: SBO Diesel Generator in Maintenance	1.011	1.029
Equivalent RRW Value of Events =	1.04	1.103

For independent events such as these, the RRW values can be combined to obtain a total RRW factor. Of the “equivalent” RRW values above, the Level 2 value is the larger of the two results and if the larger 1.103 RRW is assumed to apply to both the CDF and the Level 2 results, the impact of eliminating SBO EDG failures can be estimated. This is done by dividing the SAMA 1 internal events MACR of $5,580,172 by 1.103 and subtracting the result from the SAMA 1 internal events MACR, which yields $521,086 ($5,580,172 - ($5,580,172 / 1.103) = $521,086).

This can be done because the relationship between the MACR and the frequencies is linear and because the larger of the two "equivalent" RRW values was used to represent both the Level 1 and Level 2 results.

E.6.25.3 EXTERNAL FLOODING EVALUATION

This SAMA can have an impact on any scenario requiring the operation of the SBO EDG. For the external flooding cases, the three flood regimes are impacted differently:

- Floods over 310' msl: In these scenarios, the safety equipment is flooded and the addition of another EDG would have no impact on risk.
- Floods between 305' and 310' msl: Most of the sequences would not be impacted by the addition of another EDG as core damage is caused by failure of the flood gates (the safety equipment is flooded) or because a flood warning is not provided and no preparations are made for the flood (the safety equipment is flooded). Flood sequence "E" represents cases where the flood gates are correctly installed, but a loss of all AC power leads to core damage. In these cases, the installation of another EDG could provide a large benefit. For the purposes of this evaluation, it is assumed that SAMA 25 will eliminate all of the contribution from Sequence "E".
- Floods below 305' mls: The only impact these flood scenarios have on the plant is the potential to cause a loss of offsite power. SAMA 25 would have an impact on these SAMAs and for the purposes of this analysis, all risk from this flood sequence is assumed to be eliminated.

The following tables summarize the results of these changes:

SAMA 25 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	7.72E-05	166.08	$508,082
Percent Change	-4.8%	-6.3%	-6.3%

A further breakdown of this information is provided below according to release category.

SAMA 25 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' Sequence A	305' to 310' Sequence B	305' to 310' Sequence C	305' to 310' Sequence D	305' to 310' Sequence E	305' to 310' Sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	0.00E+00	8.65E-08	0.00E+00	7.72E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	132.75	13.13	0.19	1.89	17.87	0.00	0.25	0.00	166.08
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$405,951	$40,149	$598	$5,767	$54,839	$0	$778	$0	$508,082

Based on these results, the external flooding component of the averted cost-risk can then be calculated:

SAMA 25 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$14,598,420	$945,053

E.6.25.3 COST OF IMPLEMENTATION

Browns Ferry estimated the cost of installing an additional EDG to be $6 million. While there are estimates as high as $25 million used in SAMA analyses for the installation of additional EDGs, the Browns Ferry estimate is used for TMI-1.

E.6.25.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 25 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$521,086	$945,053	$1,466,139	$6,000,000	-$4,533,861

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.26 SAMA NUMBER 26: REROUTE CABLES SO THAT THEY DO NOT PASS OVER IGNITION SOURCES IN FIRE ZONE CB-FA-2E (WEST INVERTER ROOM) OR WRAP THEM IN FIRE PROOF MATERIAL

The TMI-1 IPEEE fire analysis identified that cables important to control functions for essential AC panels (including Bus 1E) were routed over potential ignition sources in fire zone CB-FA-2E. Some of the risk from this fire zone could be averted if these cables were protected or rerouted such that battery charger/inverter fires would not result in damage to the cables. While these changes would not eliminate the risk corresponding to the ignition source fires, the cables are the dominant risk contributors for the zone. Two potential methods of mitigating the fire risk in CB-FA-2E have been identified for this SAMA

- Method A: Rerouting the cables so that they do not pass over the battery chargers or inverters or,
- Method B: Providing fire barriers capable of preventing fire propagation and damage to the overhead cables.

Both of these changes are assumed to be capable of preventing damage to the overhead cables. Rerouting the cables has the potential to completely eliminate the risk of cable damage while use of fire barriers has some non-zero failure rate associated with the barriers, but for this analysis, both approaches are assumed to completely eliminate the risk of cable damage.

The impact of these types of changes has been estimated using available information from the fire model and engineering judgment. No model quantification was performed for this evaluation.

It is assumed that if the portion of the fire CDF and release consequences related to cable damage in fire zone CB-FA-2E can be identified, then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below:

- Determine the component of the overall modified MACR attributable to non-external flooding external events,
- Determine the component of the non-external flooding external events cost-risk attributable to fire events,
- Determine the component of the fire based cost-risk attributable to fire zone CB-FA-2E,

- Determine the component of the fire based cost-risk attributable to the AC panel control cables located in fire zone CB-FA-2E,
- Calculate the percent reduction in the fire CB-FA-2E CDF that would occur if the SAMA is implemented and reduce the cost-risk for the fire zone by the same percent. The reduction in cost-risk is the averted cost-risk for this SAMA.

The baseline assumption for non-external flooding external events contributions in the TMI-1 SAMA is that they are approximately equal to the internal events contributions. Given that the internal events MACR is $3,271,711, the same value is assigned to external events.

The relative contribution of fire events to the total external events CDF is difficult to determine due to the fact that the methods of analysis for each of the external events types are not necessarily compatible. If the comparison is made strictly on the basis of the calculated CDFs, the fire contribution would only be 20.1%:

External Events Contribution Summary

External Event	CDF	Percent of Total Non-External Flooding External Events CDF
Seismic (based on LLNL seismic hazard curves)	8.43E-05/yr	78.6%
Fire*	2.16E-05/yr	20.1%
High Winds	7.77E-07/yr	0.7%
Aircraft Impact**	3.95E-07/yr	0.4%
Hazardous Chemicals	1.60E-07/yr	0.1%
Total	**1.07E-04/yr**	

*Includes the error in the IPEEE that results in overestimation of the CB-FA-2E fire zone frequency.

**This includes the contribution from accidental aircraft impact only. Intentional aircraft impact is addressed in separate plant programs and is beyond the scope of the SAMA analysis.

For seismically stable regions, the fire CDF is typically greater than the seismic CDF and for TMI-1, a larger value than the 20 percent identified in the table above is considered to be appropriate. For the purposes of this calculation, the fire CDF is assumed to be 85 percent of the total non-external flooding external events CDF. This corresponds to a cost-risk of $2,780,954 ($3,271,711 * 0.85 = $2,780,954).

The cost-risk associated with fire zone CB-FA-2E can then be determined based on its relative contribution to the total fire CDF by assuming the fire zone specific MACR is directly proportional to the CDF. For this calculation, the error identified in the IPEEE related to the CB-FA-2E CDF has been corrected:

Fire Area/Scenario	Description	CDF[1]	Percent of Total Fire CDF	Fire Zone Specific MACR
CB-FA-2d	East Inverter Room	4.94E-06/yr	26.17%	$727,776
CB-FA-2e	West Inverter Room	3.09E-06/yr	16.31%	$453,574
CB-FA-3a	1D Switchgear Room	3.94E-06/yr	20.87%	$580,385
CB-FA-3b	1E Switchgear Room	4.96E-06/yr	26.27%	$730,557
CB-FA-4b	Control Room – Console CR	1.96E-06/yr	10.38%	$288,663
	Total	1.89E-05/yr	100%	$2,780,955

The risk reduction possible for fire zone CB-FA-2E is a fraction of the total based on the potential capabilities of the changes proposed in this SAMA. Neither change (barriers or cable rerouting) is considered to be capable of preventing damage to the equipment in the cabinet where the fire starts; however, both changes are assumed to prevent damage to overhead cables. The averted cost-risk for these changes, therefore, is based on the difference between the CDF when cable damage occurs and the CDF when cable damage is eliminated.

The quantification of the CDF change due to this SAMA's implementation was performed using information from the IPEEE documentation. The IPEEE indicates that the CDF for fire zone CB-FA-2E is composed of two cases that are separated based on the location of the two batteries and two inverters in the zone. One battery and one inverter are located below the AC panel control cables and the other battery and inverter are not located below the AC power control cables. Fires in the battery or inverter below the AC control cables damage essential AC power (and are assumed to fail bus 1E), but fires in the battery or inverter located away from the AC panel control cables do not damage the AC control panel cables. The fire zone CDF for the existing plant configuration is summarized in the following table:

[1] The CB-2A-FE fire zone CDF reported in the IPEEE appears to have been overestimated due to computational errors. The correct CDF calculation for fire zone CB-FA-2E is shown here and used in the remainder of this calculation.

Current CB-FA-2E Fire Contributions

	Conditional CDF	IE Frequency	Fraction of IE Frequency Applicable	CDF
Case 1 (fires not resulting in cable failures)	1.16E-04	4.91E-03	5.00E-01	2.85E-07
Case 2 (fires resulting in cable failures)	1.14E-03	4.91E-03	5.00E-01	2.80E-06
			Total	**3.08E-06**

To represent implementation of the SAMA, Case 2 is adjusted such that the conditional CDF is equal to the conditional CDF for Case 1, which implies that the AC control cables are not damaged and that the consequences of failing either battery/inverter set are the same. The CDF results are shown below:

POST SAMA CB-FA-2E FIRE CONTRIBUTIONS

	CONDITIONAL CDF	IE FREQUENCY	FRACTION OF IE FREQUENCY APPLICABLE	CDF
Case 1 (fires not resulting in cable failures)	1.16E-04	4.91E-03	5.00E-01	2.85E-07
Case 2 (fires resulting in cable failures)	1.16E-04	4.91E-03	5.00E-01	2.85E-07
			Total	**5.70E-07**

The result is a CDF of 5.70E-7, which is 18.5 percent of the base CB-FA-2E CDF. This corresponds to a revised fire zone MACR of $83,911 ($453,574 * 0.185 = $83,911).

The difference between the baseline MACR for fire zone CB-FA-2E and MACR assuming SAMA implementation is the averted cost-risk for this SAMA: $453,574 - $83,911 = $369,663.

Of the two potential mitigation methods identified, cable wrapping (Method B) was determined to be the more cost effective approach. The cost of performing the cable wrapping in CB-FA-2e was estimated to be $900,000 by the TMI staff (Exelon 2007c).

Results

The results of the fire area analysis and the implementation cost estimates are used as input to the cost-benefit calculation. The results of this calculation are provided in the following table:

SAMA 26 - Net Value

Averted Cost-Risk	Cost of Implementation	Net Value
$369,663	$900,000	-$530,337

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.27 SAMA NUMBER 27: IMPROVE THE 480V AC LOAD CENTER WELDS

The IPEEE determined that the existing 480V AC load centers had the lowest seismic fragilities in the TMI-1 AC distribution system. Adding reinforcements to the welds on the load center framework would improve the seismic durability of the structure and increase the likelihood that the system would be available after a seismic event. The specific components considered to be addressed are 480V AC load centers 1P, 1R, 1S, and 1T, which are the components critical to improving the AC power system's seismic ruggedness. The other low seismic capacity components of the AC distribution system, the EDG air receivers, were enhanced subsequent to the completion of the IPEEE.

The ability to quantify the impact of improving the seismic capacity of the load centers is limited due to the small amount of information provided in the IPEEE related to the importance of the load centers over the four different seismic ranges evaluated. However, a process has been developed to approximate the potential benefit of increasing the HCLPF for the load centers from 0.12g to 0.30g through improvements to the welds. The revised HCLPF capacity value of 0.30g was chosen because it was used in industry seismic margins analyses as the threshold for components to be considered adequately durable. All of the calculations are based on information available in the IPEEE, the current PRA, and engineering judgment. No seismic model quantification was performed for this evaluation.

It is assumed that if the portion of the seismic CDF and release consequences related to the failures of the 480V AC load centers can be identified, then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below:

- Determine the component of the overall modified MACR attributable to non-external flooding external events,
- Determine the component of the non-external flooding external events cost-risk attributable

to seismic events,

- Determine the component of the seismic based cost-risk attributable to 480V AC load centers 1P, 1R, 1S, and 1T,

- Calculate the percent reduction in seismic CDF that would occur if the SAMA is implemented and reduce the cost-risk for the load centers by the same percent. The reduction in cost-risk is the averted cost-risk for this SAMA.

The baseline assumption for non-external flooding external events contributions in the TMI-1 SAMA is that they are approximately equal to the internal events contributions. Given that the internal events MACR is $3,271,711, the same value is assigned to external events.

The relative contribution of seismic events to the total external events CDF is difficult to determine due to the fact that the methods of analysis for each of the external events types are not necessarily compatible. If the comparison is made strictly on the basis of the calculated CDFs, the seismic contribution would be 78.6%:

External Events Contribution Summary

External Event	CDF	Percent of Total Non-External Flooding External Events CDF
Seismic (based on LLNL seismic hazard curves)	8.43E-05/yr	78.6%
Fire*	2.16E-05/yr	20.1%
High Winds	7.77E-07/yr	0.7%
Aircraft Impact**	3.95E-07/yr	0.4%
Hazardous Chemicals	1.60E-07/yr	0.1%
Total	**1.07E-04/yr**	

*Includes the error in the IPEEE that results in overestimation of the CB-FA-2E fire zone frequency.

**This includes the contribution from accidental aircraft impact only. Intentional aircraft impact is addressed in separate plant programs and is beyond the scope of the SAMA analysis.

For seismically stable regions, the fire CDF is typically greater than the seismic CDF, but for TMI-1, this is not the case when the NUREG 1488 LLNL hazard curves are used. While it may be inconsistent with many industry examples in which the fire risk outweighs the seismic risk, the 78.6 percent seismic contribution is retained for this evaluation. This corresponds to a cost-risk of $2,571,565 ($3,271,711 * 0.786 = $2,571,565).

The cost-risk associated with the 480V AC load centers can then be determined based on the overall seismic Fussell-Vesely (F-V) value for the load centers and the assumption that the overall seismic F-V value is constant over the seismic spectrum. This is typically not true, but when used over the entire seismic spectrum, it will provide a reasonable answer.

Two separate F-V values have been identified for the 480V AC load centers, which are part of the FRAG15 component group (based on the NUREG-1488 seismic hazard curve results):

- GW: offsite power available cases (F-V = 0.4),
- GY: offsite power failure cases (F-V = 0.15).

The CDF corresponding to the FRAG15 component group (the 480V load centers) can be estimated by multiplying the F-V values by the CDF for each range in the seismic spectrum, as summarized below:

GW FRAG15 Specific CDF

Initiating Event	CDF	CDF Related to FRAG15
SEIS1 (0.15g) (range = 0.052g - 0.2g)	1.26E-05	5.04E-06
SEIS2 (0.25g) (range = 0.2g - 0.3g)	2.61E-05	1.04E-05
SEIS3 (0.4g) (range = 0.3g - 0.5g)	3.25E-05	1.30E-05
SEIS4 (0.6g) (range = 0.5g - 1.01g)	1.31E-05	5.24E-06
Totals=	**8.43E-05**	**3.37E-05**

GY FRAG15 Specific CDF

Initiating Event	CDF	CDF Related to FRAG15
SEIS1 (0.15g) (range = 0.052g - 0.2g)	1.26E-05	1.89E-06
SEIS2 (0.25g) (range = 0.2g - 0.3g)	2.61E-05	3.92E-06
SEIS3 (0.4g) (range = 0.3g - 0.5g)	3.25E-05	4.88E-06
SEIS4 (0.6g) (range = 0.5g - 1.01g)	1.31E-05	1.97E-06
Totals=	**8.43E-05**	**1.26E-05**

Assuming the MACR is directly proportional to the CDF provides a means of determining the MACR for FRAG15 over the seismic spectrum given the total seismic MACR of $2,571,565:

GW FRAG15 Specific MACR

Initiating Event	CDF Related to FRAG15	MACR Related to FRAG15
SEIS1 (0.15g) (range = 0.052g - 0.2g)	5.04E-06	$153,745
SEIS2 (0.25g) (range = 0.2g - 0.3g)	1.04E-05	$318,471
SEIS3 (0.4g) (range = 0.3g - 0.5g)	1.30E-05	$396,564
SEIS4 (0.6g) (range = 0.5g - 1.01g)	5.24E-06	$159,846
Totals=	**3.37E-05**	**$1,028,626**

GY FRAG15 SPECIFIC MACR

INITIATING EVENT	CDF RELATED TO FRAG15	MACR RELATED TO FRAG15
SEIS1 (0.15g) (range = 0.052g - 0.2g)	1.89E-06	$57,654
SEIS2 (0.25g) (range = 0.2g - 0.3g)	3.92E-06	$119,427
SEIS3 (0.4g) (range = 0.3g - 0.5g)	4.88E-06	$148,711
SEIS4 (0.6g) (range = 0.5g - 1.01g)	1.97E-06	$59,942
Totals=	**1.26E-05**	**$385,735**

The quantification of the CDF change due to this SAMA's implementation was performed using information from the IPEEE documentation. The IPEEE indicates that the HCLPF capacity for FRAG15 is 0.12g and the failure probabilities for each seismic range are explicitly provided for FRAG15. In addition, the failure probabilities are explicitly provided for the BWST (FRAG21), which has a HCLPF capacity of 0.3g. It is assumed that if the 480V AC load center welds are improved, the failure probabilities can be represented by those documented for FRAG21. From these assumptions the revised CDFs, and therefore the MACRs, can be calculated. More specifically, the ratio of the post-SAMA FRAG15 failure probability to the baseline FRAG15 failure probability will be equivalent to the ratio of the post-SAMA FRAG15 CDF to the baseline FRAG15 CDF. Finally, the FRAG15 MACR is proportional to the CDF, so once the FRAG15 CDF ratio is known, the post-SAMA FRAG15 MACR can be calculated by multiplying the FRAG15 ratio by the baseline FRAG15 MACR for each seismic hazard range. The following tables summarize the results:

GW FRAG15 Specific MACR Post SAMA Implementation

Initiating Event	Baseline FRAG15 Failure Probability	Post-SAMA FRAG15 Failure Probability (0.3g HCLPF)	CDF (or FRAG15) Ratio	Baseline FRAG15 MACR	Post-SAMA FRAG15 MACR (0.3g HCLPF)
SEIS1 (0.15g) (range = 0.052g - 0.2g)	1.25E-02	2.15E-06	1.72E-04	$153,745	$26
SEIS2 (0.25g) (range = 0.2g - 0.3g)	2.67E-01	3.95E-03	1.48E-02	$318,471	$4,711
SEIS3 (0.4g) (range = 0.3g - 0.5g)	6.61E-01	4.78E-02	7.23E-02	$396,564	$28,677
SEIS4 (0.6g) (range = 0.5g - 1.01g)	9.50E-01	2.82E-01	2.97E-01	$159,846	$47,449
			Total =	**$1,028,626**	**$80,864**

GY FRAG15 SPECIFIC MACR POST SAMA IMPLEMENTATION

Initiating Event	Baseline FRAG15 Failure Probability	Post-SAMA FRAG15 Failure Probability (0.3g HCLPF)	CDF Ratio	Baseline FRAG15 MACR	Post-SAMA FRAG15 MACR (0.3g HCLPF)
SEIS1 (0.15g) (range = 0.052g - 0.2g)	1.58E-02	2.15E-06	1.36E-04	$57,654	$8
SEIS2 (0.25g) (range = 0.2g - 0.3g)	3.60E-01	3.95E-03	1.10E-02	$119,427	$1,310
SEIS3 (0.4g) (range = 0.3g - 0.5g)	8.44E-01	4.78E-02	5.66E-02	$148,711	$8,422
SEIS4 (0.6g) (range = 0.5g - 1.01g)	9.98E-01	2.82E-01	2.83E-01	$59,942	$16,938
			Total =	**$385,735**	**$26,678**

The averted cost-risk is the difference between the base FRAG15 MACRs and the post-SAMA implementation MACRs for both GW and GY, which is $1,306,819 (($1,028,626 - $80,864) + ($385,735 - $26,678) = $1,306,819).

E.6.27.1 COST OF IMPLEMENTATION

The cost of this enhancement was estimated to be $575,000 by the TMI staff (Exelon 2007c).

E.6.27.2 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is only the seismic averted cost-risk in this case, and the cost of implementation. The following table summarizes these results:

SAMA 27 - Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$1,306,819	$575,000	$731,819

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive.

E.6.28 SAMA NUMBER 28: IMPROVE THE DECAY HEAT SERVICE COOLER (DC-C-2A/B) ANCHORAGES

The IPEEE determined that the existing Decay heat service coolers (DC-C-2A/B) lacked sufficiently durable anchorages. Replacing the anchorages with more robust anchorages would improve the seismic durability of the structure and increase the likelihood that the heat exchangers would be available after a seismic event.

The ability to quantify the impact of improving the seismic capacity of the heat exchanger anchorages is limited due to the small amount of information provided in the IPEEE related to the importance of DC-C-2A/B over the four different seismic ranges evaluated. However, a process has been developed to approximate the potential benefit of increasing the HCLPF for the heat exchangers from 0.09g to 0.30g through improvements to the anchorages. The revised HCLPF capacity value of 0.30g was chosen because it was used in industry seismic margins analyses as the threshold for components to be considered adequately durable. All of the calculations are based on information available in the IPEEE, the current PRA, and engineering judgment. No seismic model quantification was performed for this evaluation.

It is assumed that if the portion of the seismic CDF and release consequences related to the failures of DC-C-2A/B can be identified, then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below:

- Determine the component of the overall modified MACR attributable to non-external flooding external events,

- Determine the component of the non-external flooding external events cost-risk attributable to seismic events,
- Determine the component of the seismic based cost-risk attributable to Decay Heat Service Coolers DC-C-2A/B,
- Calculate the percent reduction in seismic CDF that would occur if the SAMA is implemented and reduce the cost-risk for the heat exchangers by the same percent. The reduction in cost-risk is the averted cost-risk for this SAMA.

The baseline assumption for non-external flooding external events contributions in the TMI-1 SAMA is that they are approximately equal to the internal events contributions. Given that the internal events MACR is $3,271,711, the same value is assigned to external events.

The relative contribution of seismic events to the total external events CDF is difficult to determine due to the fact that the methods of analysis for each of the external events types are not necessarily compatible. If the comparison is made strictly on the basis of the calculated CDFs, the seismic contribution would be 78.6%:

External Events Contribution Summary

External Event	CDF	Percent of Total Non-External Flooding External Events CDF
Seismic (based on LLNL seismic hazard curves)	8.43E-05/yr	78.6%
Fire*	2.16E-05/yr	20.1%
High Winds	7.77E-07/yr	0.7%
Aircraft Impact**	3.95E-07/yr	0.4%
Hazardous Chemicals	1.60E-07/yr	0.1%
Total	**1.07E-04/yr**	

*Includes the error in the IPEEE that results in overestimation of the CB-FA-2E fire zone frequency.

**This includes the contribution from accidental aircraft impact only. Intentional aircraft impact is addressed in separate plant programs and is beyond the scope of the SAMA analysis.

For seismically stable regions, the fire CDF is typically greater than the seismic CDF, but for TMI-1, this is not the case when the NUREG 1488 LLNL hazard curves are used. While it may be inconsistent with many industry examples in which the fire risk outweighs the seismic risk, the 78.6 percent seismic contribution is retained for this evaluation. This corresponds to a cost-risk of $2,571,565 ($3,271,711 * 0.786 = $2,571,565).

The cost-risk associated with DC-C-2A/B can then be determined based on the overall seismic Fussell-Vesely (F-V) value for the heat exchangers and the assumption that the overall seismic F-V value is constant over the seismic spectrum. This is typically not true, but when used over the entire seismic spectrum, it will provide a reasonable answer. The overall seismic F-V value for component group FRAG11, which includes DC-C-2A/B, is 2.00E-02 (based on the NUREG-1488 seismic hazard curve results).

The CDF corresponding to the FRAG11 component group (the Decay Heat Service Coolers) can be estimated by multiplying the FRAG11 F-V value by the CDF for each range in the seismic spectrum. The following table summarizes the results:

FRAG11 Specific CDF

Initiating Event	CDF	CDF Related to FRAG11
SEIS1 (0.15g) (range = 0.052g - 0.2g)	1.26E-05	2.52E-07
SEIS2 (0.25g) (range = 0.2g - 0.3g)	2.61E-05	5.22E-07
SEIS3 (0.4g) (range = 0.3g - 0.5g)	3.25E-05	6.50E-07
SEIS4 (0.6g) (range = 0.5g - 1.01g)	1.31E-05	2.62E-07
Totals=	8.43E-05	1.69E-06

Assuming the MACR is directly proportional to the CDF provides a means of determining the MACR for FRAG11 over the seismic spectrum given the total seismic MACR of $2,571,565:

FRAG11 Specific MACR

Initiating Event	CDF Related to FRAG11	MACR Related to FRAG11
SEIS1 (0.15g) (range = 0.052g - 0.2g)	2.52E-07	$7,687
SEIS2 (0.25g) (range = 0.2g - 0.3g)	5.22E-07	$15,924
SEIS3 (0.4g) (range = 0.3g - 0.5g)	6.50E-07	$19,828
SEIS4 (0.6g) (range = 0.5g - 1.01g)	2.62E-07	$7,992
Totals=	1.69E-06	$51,431

The quantification of the CDF change due to this SAMA's implementation was performed using information from the IPEEE documentation. The IPEEE provides the seismic range specific failure probabilities for top event RX, which are driven by FRAG11 given that the HCLPF capacity is 0.09g while the only other contributing component has a HCLPF capacity of 0.43g. In addition, the failure probabilities are explicitly provided for the BWST (FRAG21), which has a HCLPF capacity of 0.30g. It is assumed that if the DC-C-2A/B anchorages are improved, the failure probabilities can be represented by those documented for FRAG21 (HCLPF for DC-C-2A/B improved to 0.30g). From these assumptions, the revised CDFs and the corresponding MACRs can be calculated using the ratio of the revised CDFs to the original CDFs. The following tables summarize the results:

FRAG11 Specific MACR Post SAMA Implementation

Initiating Event	Base FRAG11 Failure Probability (From top event RX)	FRAG11 Failure Probability After SAMA Implementation (0.3g HCLPF)	CDF Ratio	Baseline FRAG11 MACR	Post-SAMA FRAG11 MACR (0.3g HCLPF)
SEIS1 (0.15g) (range = 0.052g - 0.2g)	3.46E-02	2.15E-06	6.21E-05	$7,687	$0
SEIS2 (0.25g) (range = 0.2g - 0.3g)	4.82E-01	3.95E-03	8.20E-03	$15,924	$130
SEIS3 (0.4g) (range = 0.3g - 0.5g)	8.42E-01	4.78E-02	5.68E-02	$19,828	$1,126
SEIS4 (0.6g) (range = 0.5g - 1.01g)	9.87E-01	2.82E-01	2.86E-01	$7,992	$2,284
			Total =	**$51,431**	**$3,540**

The averted cost-risk is the difference between the base FRAG11 specific MACRs and the FRAG11 specific MACRS after SAMA implementation, which is $47,891 ($51,431 - $3,540 = $47,891).

E.6.28.1 COST OF IMPLEMENTATION

The cost of this enhancement was estimated to be $575,000 by the TMI staff (Exelon 2007c).

E.6.28.2 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is only the seismic averted cost-risk in this case, and the cost of implementation. The following table summarizes these results:

SAMA 28 - Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$47,891	$575,000	-$527,109

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.29 SAMA NUMBER 29: REPLACE EDG GROUND RESISTORS

Failure of the EDG ground resistors results in failure of the EDGs, which will lead to core damage in the event that off-site power is not available. Given that the HCLPF capacity for these components was estimated at 0.25g compared with 0.09g capacities of off-site power components (such as the 1/A and 1/B distribution buses or the aux transformers), it is likely that core damage will ensue due to long term loss of power if the EDG ground resistors fail from seismic shock. Replacing the resistors with more durable versions would improve the reliability of the EDGs in seismic events.

The ability to quantify the impact of improving the seismic capacity of the EDG ground resistors is limited due to the small amount of information provided in the IPEEE related to the importance of these components over the four different seismic ranges evaluated. However, a process has been developed to approximate the potential benefit of increasing the HCLPF capacity of the EDG ground resistors from 0.25g to a theoretical limit where it would never fail. All of the calculations are based on information available in the IPEEE, the current PRA, and engineering judgment. No seismic model quantification was performed for this evaluation.

It is assumed that if the portion of the seismic CDF and release consequences related to the failures of the EDG ground resistors can be identified, then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below:

- Determine the component of the overall modified MACR attributable to non-external flooding external events,
- Determine the component of the non-external flooding external events cost-risk attributable to seismic events,
- Determine the component of the seismic based cost-risk attributable to the EDG ground resistors,
- Assume that implementation of this SAMA would eliminate all risk related to the EDG ground resistors such that the averted cost-risk would be the total cost-risk related to the EDG ground resistors.

The baseline assumption for non-external flooding external events contributions in the TMI-1 SAMA is that they are approximately equal to the internal events contributions. Given that the internal events MACR is $3,271,711, the same value is assigned to external events.

The relative contribution of seismic events to the total external events CDF is difficult to determine due to the fact that the methods of analysis for each of the external events types are not necessarily compatible. If the comparison is made strictly on the basis of the calculated CDFs, the seismic contribution would be 78.6%:

External Events Contribution Summary

External Event	CDF	Percent of Total Non-External Flooding External Events CDF
Seismic (based on LLNL seismic hazard curves)	8.43E-05/yr	78.6%
Fire*	2.16E-05/yr	20.1%
High Winds	7.77E-07/yr	0.7%
Aircraft Impact**	3.95E-07/yr	0.4%
Hazardous Chemicals	1.60E-07/yr	0.1%
Total	1.07E-04/yr	

*Includes the error in the IPEEE that results in overestimation of the CB-FA-2E fire zone frequency.

**This includes the contribution from accidental aircraft impact only. Intentional aircraft impact is addressed in separate plant programs and is beyond the scope of the SAMA analysis.

For seismically stable regions, the fire CDF is typically greater than the seismic CDF, but for TMI-1, this is not the case when the NUREG 1488 LLNL hazard curves are used. While it may be inconsistent with many industry examples in which the fire risk outweighs the seismic risk, the 78.6 percent seismic contribution is retained for this evaluation. This corresponds to a cost-risk of $2,571,565 ($3,271,711 * 0.786 = $2,571,565).

The cost-risk associated with the EDG ground resistors can then be determined based on the overall seismic Fussell-Vesely (F-V) value for the EDG ground resistors and the assumption that the overall seismic F-V value is constant over the seismic spectrum. This is typically not true, but when used over the entire seismic spectrum, it will provide a reasonable answer. The overall seismic F-V value for FRAG17, which represents the EDG ground resistors, is 1.00E-02 (based on the NUREG-1488 seismic hazard curve results).

The CDF corresponding to the FRAG17 component group (the EDG ground resistors) can be determined by multiplying the FRAG-17 F-V value by the CDF for each range in the seismic spectrum. The following table summarizes the results:

FRAG17 Specific CDF

Initiating Event	CDF	CDF Related to FRAG17
SEIS1 (0.15g) (range = 0.052g - 0.2g)	1.26E-05	1.26E-07
SEIS2 (0.25g) (range = 0.2g - 0.3g)	2.61E-05	2.61E-07
SEIS3 (0.4g) (range = 0.3g - 0.5g)	3.25E-05	3.25E-07
SEIS4 (0.6g) (range = 0.5g - 1.01g)	1.31E-05	1.31E-07
Totals=	8.43E-05	8.43E-07

Assuming the MACR is directly proportional to the CDF provides a means of determining the MACR for FRAG17 over the seismic spectrum given the total seismic MACR of $2,571,565:

FRAG17 Specific MACR

Initiating Event	CDF Related to FRAG17	MACR Related to FRAG17
SEIS1 (0.15g) (range = 0.052g - 0.2g)	1.26E-07	$3,844
SEIS2 (0.25g) (range = 0.2g - 0.3g)	2.61E-07	$7,962
SEIS3 (0.4g) (range = 0.3g - 0.5g)	3.25E-07	$9,914
SEIS4 (0.6g) (range = 0.5g - 1.01g)	1.31E-07	$3,996
Totals=	8.43E-07	$25,716

Following the assumption that implementation of this SAMA can eliminate all risk related to the EDG ground resistors, the averted cost-risk is the total MACR for FRAG17, which is $25,716.

E.6.29.1 COST OF IMPLEMENTATION

The cost of this enhancement was estimated to be $800,000 by the TMI staff (Exelon 2007c).

E.6.29.2 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is only the seismic averted cost-risk in this case, and the cost of implementation. The following table summarizes these results:

SAMA 29 - Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$25,716	$800,000	-$774,284

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.30 SAMA NUMBER 30: IMPROVE DIESEL FIRE PUMP FUEL OIL TANK AND BATTERY RACK SUPPORTS

The Fire Service Water system provides cooling to the SBO EDG, backup cooling the DHCCW heat exchangers, and backup cooling to the "1A" and "1B" Instrument Air compressors. While seismic failures to the systems FSW supports would likely limit the benefit of improving the fuel oil tank and battery racks, some benefit may be available through improvements to the diesel fire pump’s reliability.

The ability to quantify the impact of improving the seismic capacity of the diesel fire pump is limited due to the small amount of information provided in the IPEEE related to the importance of the fire system. The motor driven pump (FS-P-2) appears to be explicitly included in the mode, but the diesel driven pumps (FS-P-1, FS-P-3) are not. However, a process has been developed to approximate the potential benefit of increasing the HCLPF capacity of the diesel driven pumps to a theoretical limit where they would never fail based on the seismic F-V value of the lowest contributor. All of the calculations are based on information available in the IPEEE, the current PRA, and engineering judgment. No seismic model quantification was performed for this evaluation.

It is assumed that if the portion of the seismic CDF and release consequences related to the failures of the diesel driven fire pump can be identified, then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below:

- Determine the component of the overall modified MACR attributable to non-external flooding external events,
- Determine the component of the non-external flooding external events cost-risk attributable to seismic events,
- Determine the component of the seismic based cost-risk attributable to the lowest reported

seismic component group (EDG ground resistors),

- Assume that the seismic importance of the diesel driven fire pumps is equivalent to the EDG ground resistors,

- Assume that implementation of this SAMA would eliminate all risk related to the diesel driven fire pumps such that the averted cost-risk would be the total cost-risk related to the diesel driven fire pumps (equivalent to the MACR for the EDG ground resistors).

Because neither the fire water system nor any fire water component was included in the seismic "system" or "component" importance lists, it is assumed that the MACR for the diesel fire driven pumps could not exceed that of the lowest component on the importance list. The IPEEE indicates that the lowest seismic F-V contributor is FRAG17, which represents the EDG ground resistors. Given that the MACR for FRAG17 was calculated in Section E.6.29, the calculations are not reproduced here, but the result was determined to be $25,716. This is considered to be the MACR for the diesel driven fire pumps.

E.6.30.1 COST OF IMPLEMENTATION

The cost of this enhancement was estimated to be $150,000 by the TMI staff (Exelon 2007c).

E.6.30.2 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is only the seismic averted cost-risk in this case, and the cost of implementation. The following table summarizes these results:

SAMA Number 30 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$25,716	$150,000	-$124,284

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

E.6.31 SAMA NUMBER 31: MODIFY SPECIFIC CONTAINMENT PENETRATION MOVS TO FAIL CLOSED

Most containment penetrations have AOV or SOV isolation valves that will fail closed on loss of air or power; however, there are cases in which MOVs are used instead. Those lines that do not include a pair of AOVs or SOVs that fail closed are typically below 1" in diameter or include at least one AOV or SOV that will fail closed on loss of air or power. However, the Nuclear Services Closed Cooling Water (NSCCW) and Reactor Building Normal Cooling (RBNC) systems include penetrations that only include MOVs:

- Valves NS-V-4, NS-V-15, NS-V-35 (NSCCW),
- Valves RB-V-2A, RB-V-7 (RBNC)

While these are closed cooling systems that would not normally provide a credible release path, heat exchanger breaks in seismic events could provide containment bypass routes given that a break occurs in the reactor building as well. Changing one of the valves in each of these paths to fail closed is a means of increasing the isolation probability over what is available from manual action.

Further review of the seismic design of the NSCCW and RBNC systems showed that while the heat exchangers linked to the penetrations in question were relatively weak, the piping and equipment associated with these lines within the reactor building were screened in the IPEEE as high capacity components. This indicates that failure of the piping and components within the reactor building would not occur except under the most extreme seismic conditions. In those cases, other integrity issues would likely exist and preventing a break in the NSCCW and RBNC lines would not provide any benefit. For reference purposes, an estimate of the cost required to replace the existing isolation valves with “fail closed”, solenoid operated AOVs was prepared and determined to be $4,100,000 (Exelon 2007c), which is greater than the entire baseline external events cost-risk of $3,271,711. This SAMA is screened from further consideration.

E.6.32 SAMA NUMBER 32: PRE-STAGE SEVERE EXTERNAL FLOODING EQUIPMENT

The existing severe flooding guidelines, which address external floods greater than 309’ msl (stillwater level, 310’ msl assumed wave action level), provide the TSC with information and guidance to help it direct the installation of “flood safe” primary and secondary side makeup systems. The guidance currently requires a large number of tasks in potentially challenging environmental conditions to prepare the plant for extreme flooding conditions. Review of the guidelines has resulted in the identification of several areas that could be improved to reduce the time required to implement the procedures and to improve the reliability of the process.

While the details of the enhancements have not yet been developed, the following high level improvements have been established as desirable for inclusion:

- Fully proceduralize guidelines: Upgrade the guidelines so that they provide step by step instructions on all aspects of the implementation process. For example, the guidelines currently direct connections to power and air sources without specifying the steps required to complete the connection. The details for these types of tasks must be provided,
- Permanently mount the power cables between the generator and pump staging areas,
- Permanently mount the emergency seal injection pump with a suction source from the fuel transfer tubes and use it in place of the submersible injection pumps to take advantage of its capability of injecting at normal operating pressure (rather than the 1200 psig available from the submersible pumps). The pump must be positioned at a flood-safe height,
- Permanently mount injection lines required for primary and secondary side makeup (may not be practical for the secondary side pump that takes suction from flood water in the turbine building),
- Consider an alternate secondary side suction source given that flood waters may recede well before an alternate secondary side makeup source will become available when AC power is re-established to the site,
- Ensure the power cables have all required connectors attached or stored in the staging areas,
- Pre-manufacture any required air supply or fuel oil connectors and store them in the staging areas,
- Store the portable generator on the turbine deck,
- Install a normally empty fuel oil tank for EG-Y-6 on the turbine deck that can be filled when it is required using power from EG-Y-6, if necessary.

Based on the IPEEE evaluation, one of the larger contributors to the severe flooding mitigation strategy is the reliability of EG-Y-6. For the 48 hour mission time evaluated in the relevant external flooding scenarios, the failure probability for EG-Y-6 is nearly 1.5E-01. This estimate is based on the use of the failure probabilities established for the large 4kV EDGs used to power the emergency buses at TMI. While the use of the EDG failure data for EG-Y-6 is believed to be conservative, component specific failure data for EG-Y-6 is not available. As a result, the design of this SAMA requires the purchase of an alternate, diverse portable generator to serve as a backup AC power source.

E.6.32.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMA's averted cost-risk associated with the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

In this case, the changes to the extreme flooding mitigation strategy are not expected to impact internal events or non-flooding external events risk. This is because the primary injection alignment cannot be performed before RCP seal heatup/damage in SBO events or other scenarios that lead to loss of seal cooling. For a majority of the external flooding cases, the severe flooding primary injection strategy could be aligned before the loss of on-site AC power such that seal cooling would never be lost. For the internal events model, there is no adequate warning that would allow such an early alignment and the only result from using the severe flooding primary injection method would likely be thermal shock to the RCP seals.

Based on the discussion above, this SAMA does not reduce internal events risk, as summarized below:

SAMA 32 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	2.37E-05	32.61	$112,259
Percent Change	0.0%	0.0%	0.0%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 32 - Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259

The non-external flooding external events contribution is typically calculated using the 2.0 multiplier on the internal events results, but in this case, the averted cost-risk is $0, so the non-external flooding external events contribution is also $0:

SAMA 32 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$3,271,711	$0	2.0	$0

E.6.32.2 EXTERNAL FLOODING EVALUATION

The severe flooding guidelines were originally credited in the IPEEE for both floods above 310' msl as well as for floods between 305' and 310' msl. Due to a more limited preparation time for the 305' to 310' msl floods, the failure probability was assumed to be 0.5 rather than the 0.255 used for the 310' msl floods. For floods below 305' msl, no credit was taken for the severe flooding guidelines as the submersible pumps used for secondary side makeup require flood water in the turbine building for a suction source. While this SAMA includes provisions for an alternate secondary side pump suction source, the expected alignment time of approximately 2 hours would likely preclude it from being an effective means of preventing core damage in a flood induced loop. In these cases, the alignment of the severe flood equipment would not begin in time to establish cooling before core melt.

For the purposes of this analysis, implementation of this SAMA is assumed to reduce the HEP for alignment of the external flooding measures from 1.1E-01 to 1.0E-02. In addition, the availability of the diverse, alternate portable AC generator is considered to reduce the failure probability of the flood-safe AC power source from 1.43E-01 to 2.04E-02 (1.43E-01 * 1.43E-01 = 2.04E-2, which assumes completely independent generators). This results in a total failure probability of 3.04E-02 (1.0E-02 + 2.04E-02 = 3.04E-02) for the severe flooding mitigation strategy.

Because the severe flooding guidelines were credited differently in each of the flood ranges, three separate strategies are required to obtain the revised core damage frequencies for the flooding scenarios:

- Floods >310' msl: The CDF for this scenario was calculated in the IPEEE as the product of the flood frequency and the failure probability for the alignment of the severe flooding mitigation strategy. As a result, the revised frequency can be obtained by multiplying the base CDF by the ratio of SAMA based severe flood mitigation failure probability to the baseline severe flood mitigation failure probability (3.04E-02 / 2.55E-01 = 1.19E-01).

- Floods between 305' and 310' msl: In the IPEEE, a multiplier of 0.5 was applied to each of the sequences in the flooding event tree to represent the potential to avert the flood using the severe flooding guidelines. The increase in the failure probability over the >310' msl case was made to account for the decreased time available in the 305' and 310' msl cases. For this evaluation, it is assumed that the failure to implement SAMA 32 is dominated by operator dependence. Non-negligible dependence exists between the actions to install the flood gates and to implement SAMA 32; however, the dependence is cognitive. As execution failure would be the majority contributor to the flood HEPs and because the execution and cognitive contributors are not separated for the flood actions, it could be overly conservative to use the dependence factors based on the available HEPs, especially given that the appropriate dependence level would likely be "high". To simulate the results of a true dependence assessment where the cognitive and execution components of the HEP are explicitly provided, a moderate dependence factor is used rather than a high dependence factor. As a result, the base event tree failure probabilities are multiplied by 0.14 (which is obtained from equation 10-16 of NUREG/CR-1278 (NRC 1983)) rather than 0.5 to get the new frequencies. In order to obtain the post-SAMA frequencies for these sequences, the flood frequencies reported in the IPEEE are multiplied by 0.28

(0.14/0.5=0.28) to account for the original 0.5 failure probability assigned to the contemporary severe flooding guidelines. Sequence "F" represents failure of the early flood warning and precluded the use of the flood panels in the IPEEE; however, credit was taken for the severe flood guidelines in the same manner as for the other sequences. For consistency with the IPEEE, the same credit taken for SAMA 32 in the other 305' to 310' msl sequences is also taken for Sequence "F". Given that Sequence "F" is a minimal contributor, this assumption has no meaningful impact on the results.

- Floods below 305' msl: While there are provisions to use a non-floodwater suction source for SAMA 32, the 2 hour alignment time may make it ineffective to prevent CD after flood induced LOOP. No credit is taken for SAMA 32 for these floods.

The results of this process are summarized below:

SAMA 32 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	1.26E-05	28.5	$87,324
Percent Change	-84.4%	-83.6%	-83.9%

A further breakdown of this information is provided below according to release category.

SAMA 32 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' sequence A	305' to 310' sequence B	305' to 310' sequence C	305' to 310' sequence D	305' to 310' sequence E	305' to 310' sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	7.58E-06	1.76E-06	1.86E-08	2.53E-07	1.71E-06	1.02E-06	2.42E-08	2.50E-07	1.26E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	15.80	3.68	0.05	0.53	5.00	3.00	0.07	0.37	28.50
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$48,308	$11,242	$167	$1,615	$15,355	$9,200	$218	$1,219	$87,324

The external flooding based averted cost-risk for this SAMA is shown below:

SAMA 32 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$2,491,451	$13,052,022

E.6.32.3 COST OF IMPLEMENTATION

The cost of implementation is estimated to be $1,700,000 (Exelon 2007c).

E.6.32.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 32 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$0	$13,052,022	$13,052,022	$1,700,000	$11,352,022

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive.

E.6.33 SAMA NUMBER 33: INCREASE THE FLOOD PROTECTION HEIGHT

The current configuration protects to the design basis limit of 310 feet msl and levels any higher result in topping of the existing flood doors and flooding of sensitive areas. Raising the height of the flood doors (completely sealing the doors, raising required air intakes/exhaust ducts, as required) would prevent water incursion and allow for continued operation of the normal safety equipment. The goal of this SAMA is to increase the flood protection height to a point where the extreme flooding CDF would be comparable to the internal events CDF of 2.37E-05/yr. In this case, the goal is assumed to be a CDF of 1.0E-05/yr and the assumption is made that when the flood waters exceed the flood protection height, core damage occurs (no credit taken for existing extreme flooding guidance). The exceedance frequency of 1E-05/yr corresponds to a level of 320.3’ msl (stillwater level). Protecting the plant against these floods would require modifications to match the stillwater of 320.3’ msl plus the wave setup height, which was determined to be up to 4’ (GPU 1990). The total flood protection height required is, therefore, 324.3’ msl, which is rounded up to 324.5’ msl.

Based on a review of plant documentation, the following changes would be required to protect the plant up to 324.5’ msl:

- EDG Building, GATE D1: Raise the flood gate to completely seal the door.
- EDG Building, GATE D2: Sealed by security changes, no additional changes are required.
- EDG Building, GATE D3: Raise the flood gate to completely seal the door.
- EDG Building, GATE D4: The gates must be extended from 311’-0” to 324.5’.
- EDG Building, Air Vent Valve: A 2-1/2” diameter penetration is located at elevation 311’-2” in the north wall and one in the west wall at elevation 312’-4” for fuel oil day tank air vent valves. Both penetrations must be waterproofed and the outlets must be extended to 324.5’.
- Air Intake Structure, Access Door: The bottom of the door is at 312’-0” and has no flood protection. The door should be completely sealed.
- Air Intake Structure, Air Vents: The bottoms of the intake louvers are a 312’. These must be completely sealed.
- Intermediate Building, Gate C-1: The tops of the existing gates are at 311’-6” and leave about 3 feet open to the top of the doorway. The door should be completely sealed and fitted with an entry hatch.
- Control Building, Gate B-1: The tops of the existing gates are at 311’ and leave an additional 10 feet open to the top of the doorway. The doors should be sealed and fitted with an entry hatch. Covering the entire doorway may not be required, but the conservative modification would be to provide complete protection.
- Control Building, Gate B-2: The tops of the existing gates are at 311’ and leave an additional 2 feet open to the top of the doorway. The door should be completely sealed and fitted with an entry hatch.

- Intake Screen Pumphouse, Gate E-1: The tops of the existing gates are at 311’ and leave an additional 4 feet open to the top of the doorway. The door should be completely sealed and fitted with an entry hatch.

- Intake Screen Pumphouse, Gate E-4: The tops of the existing gates are at 311’ and leave an additional 6 feet open to the top of the doorway. The door should be completely sealed and fitted with an entry hatch.

- Intake Screen Pumphouse, Gate E-2: The tops of the existing gates are at 311’ and leave an additional 4 feet open to the top of the doorway. The door should be completely sealed and fitted with an entry hatch.

- Intake Screen Pumphouse, Gate E-3: The tops of the existing gates are at 311’ and leave an additional 4 feet open to the top of the doorway. The door should be completely sealed and fitted with an entry hatch. In addition, two penetrations exist at 311’-4” and 312’-8” and an exhaust penetration exists in the west wall. These penetrations must be sealed and communication with the atmosphere must be provided at a level of at least 324.5’.

In addition, there is concern that the cable vaults holding the cables that connect the EDGs to the emergency buses are not waterproof. These cable vaults must be waterproofed so that the EDG output cables do not short out in the event that the cables have lost integrity.

E.6.33.1 INTERNAL EVENTS AND NON-EXTERNAL FLOODING EVALUATION

This subsection describes the calculation of the component of this SAMA’s averted cost-risk associated with the non-external flooding events. As described in Section E.4.6.3, the external events risk, excluding external flooding, is considered to be equal to the internal events risk. Quantitatively, this is accounted for by multiplying the internal events averted cost-risk by a factor of 2.0. This process is described below and is one of the two components that comprise the total averted cost-risk for a SAMA.

In this case, the changes to the extreme flooding protection height will not impact internal events or non-flooding external events risk and this SAMA will not reduce the CDF, dose risk, or OECR, as summarized below:

SAMA 33 - Internal Events Results

	CDF (/yr)	Dose-Risk	OECR
Base Results	2.37E-05	32.61	$112,259
SAMA Results	2.37E-05	32.61	$112,259
Percent Change	0.0%	0.0%	0.0%

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

SAMA 33 Internal Events Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{SAMA}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{SAMA}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{SAMA}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{SAMA}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{SAMA}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{SAMA}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259

The non-external flooding external events contribution is typically calculated using the 2.0 multiplier on the internal events results, but in this case, the averted cost-risk is $0, so the non-external flooding external events contribution is also $0:

SAMA 33 - Non-External Flooding Averted Cost-Risk

Base Case Internal Events Cost-Risk	SAMA Case Internal Events Cost-Risk	Internal Events Averted Cost-Risk	Non-Flood External Events Multiplier	Total Non-Flood Averted Cost-Risk
$3,271,711	$3,271,711	$0	2.0	$0

E.6.33.2 EXTERNAL FLOODING EVALUATION

This SAMA only has the potential of reducing the risk of the extreme floods, those which result in flood waters exceeding 310' msl. The lesser floods are already protected by dikes or flood gates and for those cases where flood gate installation fails, this SAMA would also fail.

For the purposes of this analysis, implementation of this SAMA is assumed to eliminate extreme flooding risk if installed properly. The same failure probability used in the IPEEE for installing the flood doors for the 305' to 310' msl floods is used for the floods over 310' (HSL1 at 5.62E-02). In this case, no credit is taken for the implementing the existing severe flooding guidelines in the event that SAMA 33 is implemented and fails. SAMA 33 impacts neither the 305' to 310' msl floods nor the floods below 305' msl. The results of this assumption are summarized below:

SAMA 33 - External Flooding Results

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
SAMA Results	3.14E-5	73.59	$225,428
Percent Change	-61.3%	-58.5%	-58.4%

A further breakdown of this information is provided below according to release category.

SAMA 33 - External Flooding Contributions by Release Category

Flood Category	>310'	305' to 310' sequence A	305' to 310' sequence B	305' to 310' sequence C	305' to 310' sequence D	305' to 310' sequence E	305' to 310' sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
SAMA Frequency	1.40E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	3.14E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
SAMA Dose-Risk	29.18	13.13	0.19	1.89	17.87	10.71	0.25	0.37	73.59
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
SAMA OECR	$89,220	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$225,428

The external flooding based averted cost-risk for this SAMA is shown below:

SAMA 33 - External Flooding Averted Cost-Risk

Base Case External Flooding Cost-Risk	SAMA Case External Flooding Cost-Risk	External Flooding Averted Cost-Risk
$15,543,473	$6,401,188	$9,142,285

E.6.33.3 COST OF IMPLEMENTATION

The cost of this enhancement was estimated to be $2,700,000 by the TMI staff (Exelon 2007c).

E.6.33.4 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk, which is the sum of the external flooding and non-external flooding based averted cost-risks, and the cost of implementation. The following table summarizes these results:

SAMA 33 - Net Value

Non-External Flooding Based Averted Cost-Risk	External Flooding Based Averted Cost-Risk	Total Averted Cost-Risk	Cost of Implementation	Net Value
$0	$9,142,285	$9,142,285	$2,700,000	$6,442,285

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive.

E.7 UNCERTAINTY ANALYSIS

Sensitivity cases were run for the following conditions to assess their impact on the overall SAMA evaluation:

Use the 95th percentile PRA results in place of the mean PRA results.

Assume no baseline BWST Refill capability

- Use alternate MACCS2 input variables for selected cases.

- Assume no credit for extreme external flooding guidance

E.7.1 95TH PERCENTILE PRA RESULTS

The results of the SAMA analysis can be impacted by implementing conservative values from the PRA's uncertainty distribution. 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 the 95th percentile results to examine the impact of uncertainty in the PRA model.

For TMI-1, the UNCERT32 software code was used to perform the Level 1 internal events model uncertainty analysis. The results of the calculation are provided below:

Parameter	Value
Mean	4.10E-05
5 percent	8.98E-06
50 percent	1.81E-05
95 percent	6.51E-05
Standard Deviation	9.36E-04

The PRA uncertainty calculation identifies the 95th percentile CDF as 6.51E-05 per year. This is a factor of 2.75 greater than the CDF point estimate produced by the TMI-1 PRA.

E.7.1.1 PHASE I IMPACT

For Phase I screening, use of the 95th percentile PRA results will increase the MACR and for some sites, it may prevent the screening of some of the higher cost modifications. In the event that a SAMA is retained based on use of the 95th percentile MACR, it would be unlikely to impact the SAMA conclusions. This is due to the fact that the benefit gleaned from the implementation of those SAMAs must be extremely large in order to be cost beneficial. For TMI-1, no SAMAs were screened in Phase I, so use of the 95th percentile PRA results does not impact the Phase I analysis. However, the 95th percentile PRA results MACR is calculated here for completeness.

As discussed above, the 95th PRA results are approximately a factor of 2.75 greater than the point estimate CDF. The uncertainty analyses that are available for the Level 1 models are not available for Level 2 and 3 PRA models. In order to simulate the use of the 95th percentile results for the Level 2 and 3 models, the same scaling factor calculated for the Level 1 results was assumed to apply to the Level 2 and 3 models. Because the MACR calculations scale linearly with the CDF, dose-risk, and offsite economic cost-risk, the 95th percentile MACR can be calculated by multiplying the base case MACR by 2.75. This results in a 95th percentile MACR of $60,739,250.

E.7.1.2 PHASE II IMPACT

As mentioned above, the 95th percentile PRA results are not available for the Level 2 and 3 models. In order to estimate the impact of using the 95th percentile PRA results in the Phase II SAMA analysis, the same process used to calculate the revised MACR was applied to each of the Phase II SAMAs (the averted cost-risk for each SAMA was increased by a factor of 2.75 over the base case).

The following table provides a summary of the impact of using the 95th percentile PRA results in the detailed cost-benefit calculations that have been performed.

Results Summary for the 95th Percentile PRA Results

SAMA ID	Cost of Implement-ation	Averted Cost- Risk (Base)	Net Value (Base)	Averted Cost- Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effective-ness?
SAMA 1	$3,125,000	$986,145	-$2,138,855	$2,711,899	-$413,101	No
SAMA 2	$7,300,000	$4,297,001	-$3,002,999	$11,816,753	$4,516,753	Yes
SAMA 3	$2,450,000	$594,926	-$1,855,074	$1,636,047	-$813,954	No
SAMA 5	$3,150,000	$230,163	-$2,919,837	$632,948	-$2,517,052	No
SAMA 6	$2,750,000	$398,924	-$2,351,076	$1,097,041	-$1,652,959	No
SAMA 7	$1,000,000	$449,254	-$550,746	$1,235,449	$235,449	Yes
SAMA 8	$145,000	$1,234,676	$1,089,676	$3,395,359	$3,250,359	No
SAMA 10	$3,800,000	$982,048	-$2,817,952	$2,700,632	-$1,099,368	No
SAMA 11	$4250,000	$16,088,692	$11,838,692	$44,243,903	$39,993,903	No
SAMA 12	$50,000	$198,438	$148,438	$545,705	$495,705	No
SAMA 13	$950,000	$305,294	-$644,706	$839,559	-$110,442	No
SAMA 14	$3,150,000	$603,886	-$2,546,114	$1,660,687	-$1,489,314	No
SAMA 15	$450,000	$199,098	-$250,902	$547,520	$97,520	Yes
SAMA 16	$1,100,000	$1,592,631	$492,631	$4,379,735	$3,279,735	No
SAMA 17	$950,000	$51,988	-$898,012	$142,967	-$807,033	No
SAMA 18	$100,000	$33,260	-$66,740	$91,465	-$8,535	No
SAMA 19	$760,000	$3,127,876	$2,367,876	$8,601,659	$7,841,659	No
SAMA 20	$3,030,000	$173,974	-$2,856,026	$478,429	-$2,551,572	No
SAMA 21	$1,200,000	$1,181,137	-$18,863	$3,248,127	$2,048,127	Yes
SAMA 22	$5,000,000	$1,253,768	-$3,746,232	$3,447,862	-$1,552,138	No
SAMA 23	$50,000	$30,629	-$19,371	$84,230	$34,230	Yes
SAMA 24	$8,400,000	$4,416,201	-$3,983,799	$12,144,553	$3,744,553	Yes
SAMA 25	$6,000,000	1,466,139	-$4,533,861	$4,031,882	-$1,968,118	No
SAMA 26	$900,000	$369,663	-$530,337	$1,016,573	$116,573	Yes
SAMA 27	$575,000	$1,306,819	$731,819	$3,593,752	$3,018,752	No
SAMA 28	$575,000	$47,891	-$527,109	$131,701	-$443,299	No
SAMA 29	$800,000	$25,716	-$774,284	$70,719	-$729,281	No
SAMA 30	$150,000	$25,716	-$124,284	$70,719	-$79,281	No
SAMA 32	$1,700,000	$13,052,022	$11,352,022	$35,893,061	$34,193,061	No
SAMA 33	$2,700,000	$9,142,285	$6,442,285	$25,141,284	$22,441,284	No

Of the SAMAs classified as “not cost beneficial” in the baseline Phase II analysis, seven SAMAs (2, 7, 15, 21, 23, 24, and 26) were found to be cost beneficial when the 95th percentile PRA results were applied. The use of the 95th percentile PRA results is not considered to provide the most realistic assessment of the cost effectiveness of a SAMA; however, these seven additional SAMAs could be considered for implementation to address the uncertainties inherent in the SAMA analysis.

E.7.2 BWST REFILL CAPABILITY

A recent inspection at TMI questioned the viability of preventing core damage in SGTR scenarios by refilling the BWST. Specifically, it is not certain whether the BWST can be refilled at a rate that will completely make up for the inventory being lost through the tube rupture. Analysis has shown that in certain scenarios (e.g., no RCS cooldown and depressurization), the current BWST refill capability will only delay core damage, but not prevent it. Because SGTR events are large contributors to the TMI-1 dose-risk and OECR, changes to the assumptions related to BWST refill capabilities can have a significant impact on the accident consequence analysis given that successful BWST refill is assumed to avert core damage. While the results of the BWST refill analysis have not yet been finalized, this sensitivity has been developed to determine how the SAMA 10 evaluation (automated BWST refill) could be impacted by the assumption that manual BWST refill is not capable of preventing core damage for SGTR events at TMI-1.

Currently, the PRA model assumes that manual refill of the BWST will support continuous makeup to the primary system, thus preventing core damage in SGTR scenarios. The importance list review showed that further improving the reliability of this function would have a meaningful impact on both the Level 1 and Level 2 results. The cost benefit results provided for SAMA 10 in Section E.6.10 are predicated on the assumption that the current BWST refill capability prevents core damage; however, if the current capability only delayed core damage to allow other recovery actions rather than prevent core damage, the impact of implementing SAMA 10 would be greater than what is shown in the baseline assessment. The averted cost-risk for the SAMA would be estimated using the difference in the MACR for the plant configuration in which BWST refill always fails and the MACR for the plant configuration in which BWST is fully automated. This is a bounding assessment since assuming no refill capability is conservative. However, detailed modeling of partial success via manual BWST refill would be very complicated and may only reduce the averted cost-risk by a small amount.

Because SAMA 10 already evaluated the plant configuration in which BWST refill is fully automated, the information required to obtain the MACR for that plant configuration is already available and is the sum of the “SAMA case external flooding cost risk” and 2 times the “SAMA case internal events cost-risk” (multiplier of 2 required to account for the non-external flooding external events contribution). As documented in Section E.6.10, the “SAMA case external flooding cost risk" is $15,543,473 and the "SAMA case internal events cost-risk" is $2,763,004. The total MACR would therefore be $21,069,481 ($15,543,473 + 2 * $2,763,004).

In order to obtain the revised baseline MACR in which BWST refill always fails, the basic event representing the independent operator action for BWST refill is set to 1.0. Because failure of the BWST refill action is a physical limitation, the JHEPs are eliminated from the results. The changes made to the cutset file to obtain the "revised baseline" results are summarized in the table below:

BWST Refill Sensitivity Model Changes

Gate and / or Basic Event ID and Description	Description of Change
BWST-HRE27-HTKOA: FAILURE TO REFILL BWST (SPLIT FRAC REV)	The basic event probability was changed from 2.65E-02 to 1.0.
JHAHCD4RE27HEPOA: AVHCD4_FF--HCDOA AND BWST-HRE27-HTKOA (JHEP addressing BWST refill and cooldown via secondary side)	The basic event probability was changed from 9.17E-05 to 0.0.
JHHRE27HL1AHEPOA: BWST-HRE27-HTKOA AND DLHHL1A----HVHOA (JHEP addressing BWST refill and opening drop line for DHR cooling)	The basic event probability was changed from 2.00E-04 to 0.0.
JHHEF2HRE27HEPOA: AVHEF2_FF--HCDOA AND BWST-HRE27-HTKOA (JHEP addressing BWST refill and manually initiating cooldown using the OTSG)	The basic event probability was changed from 1.3E-03 to 0.0.
JHHIGHREHHLHEPOA: IGHIG1_HER-HSGOA, BWST-HRE27-HTKOA, and DLHHL1A----HVHOA (JHEP addressing BWST refill, failure to isolate a SGTR, and opening drop line for DHR cooling)	The basic event probability was changed from 5.0E-07 to 0.0. (Event was not in cutsets)

The results of these changes are summarized in the tables below:

BWST Refill Sensitivity Results

	CDF (/YR)	DOSE-RISK	OECR
Sensitivity Results	2.75E-05	54.04	$216,329

A further breakdown of this information is provided below according to release category. Note that the results for the following RCs are not provided given that the frequencies are always zero: RC2-01, RC2-03, RC3-05, RC3-06, RC4-05, RC4-06, RC4-07, RC4-08, RC6-01, RC6-02, AND RC6-06.

BWST Refill Sensitivity Results By Release Category

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{Sens}$	2.33E-06	3.46E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Dose-Risk$_{Sens}$	13.33	19.79	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
OECR$_{Sens}$	$64,774	$96,188	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{Sens}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.33E-05	1.69E-08	2.36E-06	1.91E-08	2.75E-05
Dose-Risk$_{Sens}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.54	0.00	0.63	0.01	54.04
OECR$_{Sens}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,476	$4	$618	$5	$216,329

These results are converted into a cost-risk using the methods documented in Section E.4:

BWST Refill Sensitivity Non-External Flooding Cost-Risk

Sensitivity Case Internal Events Cost-Risk	Non-External Flooding External Events Multiplier	Total Non-Flood Cost-Risk
$5,578,084	2.0	$11,156,168

Assuming that the external flooding MACR is constant at $15,543,473, the total MACR for the case without BWST refill capability would be $26,699,641 ($15,543,473 + $11,156,168 = $26,699,641). It should be noted that the use of the multiplier of 2 to account for external events contributions for this case may be inappropriate because SGRT events are not considered in the external events scenarios.

Finally, the averted cost risk and net value for SAMA 10 assuming an initial configuration in which BWST refill is not credited can be recalculated:

BWST Sensitivity SAMA 10 Net Value

No BWST Refill Case MACR	Fully Automated BWST Refill MACR	Averted Cost-Risk	Cost of Implementation	Net Value
$26,699,641	$21,069,481	$5,630,160	$3,800,000	$1,830,160

Given that the net value is positive for this case, the implication is that if the actual TMI-1 conditions are best represented by no credit for BWST refill (a conservative assumption), SAMA 10 is a cost effective change.

E.7.3 MACCS2 INPUT VARIATIONS

The MACCS2 model was developed using the best information available for the Three Mile Island site; however, reasonable changes to modeling assumptions can lead to variations in the Level 3 results. In order to determine how certain assumptions could impact the SAMA results, a sensitivity analysis was performed on a group of parameters that has previously been shown to impact the Level 3 results. These parameters (and the associated sensitivity case identifiers) include:

- Meteorological data (TMI1999; TMI2000)
- Population estimates(TMI30INC; TMISIT00)
- Evacuation effectiveness (TMISLOW)
- Radionuclide release characteristics (TMIATM1; TMIATM2)
- Recovery, decontamination, and resettlement factors (Intermediate Phase) (TMICHR1, TMICHR2)

The risk metrics produced by MACCS2 that are evaluated in the sensitivity analyses are the 50 mile population dose and the 50 mile offsite economic cost. The following subsections discuss the changes in these results for each of the sensitivity cases that are shown below. The final subsection, E.7.3.6, correlates the worst case changes identified in the sensitivity runs to a change in the site's averted cost-risk and discusses the implications of the sensitivity analysis on the SAMA analysis.

CASE	DESCRIPTION	POP. DOSE RISK Δ BASE (%)	COST RISK Δ BASE (%)
TMI1998	Base Case (Year 1998 MET data)	--	--
TMI1999	Year 1999 MET data	-10.5%	-9.29%
TMI2000	Year 2000 MET data	-4.73%	-5.15%
TMI30INC	Year 2034 population values increased uniformly 30% over base case.	28.3%	29.5%
TMISit00	Year 2000 population based (Base Case is Year 2034)	-28.9%	-29.6%
TMISlow	Evacuation speed decreased 50% to 0.59 mph, 0.26 m/sec (Base Case is 1.18 mph).	15.3%	0%
TMIATM1	Release height set to ground level	-4.58%	-5.22%

CASE	DESCRIPTION	POP. DOSE RISK Δ BASE (%)	COST RISK Δ BASE (%)
TMIATM2	Plume thermal heat content set to ambient (i.e., buoyant plume rise not modeled)	1.65%	1.09%
TMICHR1	Long Term Phase starts immediately after the Early Phase is over (No Intermediate Phase; Base Case is 6 month Intermediate Phase)	16.8%	-36.9%
TMICHR2	1 Year Intermediate Phase following the Early Phase (Base Case is 6 month Intermediate Phase)	-8.84%	34.0%

E.7.3.1 METEOROLOGICAL SENSITIVITY

In addition to the base case meteorological data (year 1998), data is also analyzed for the years 1999 and 2000. Analysis of these alternate data sets yielded population dose-risks and offsite economic cost-risks that are lower than the 1998 data by at least 4.7 percent and by as much as 10.5 percent.

As no particular criteria have been defined by the industry related to determining which meteorological data set should be used as a base case for a site, the year 1998 data is conservatively chosen for Three Mile Island given that it yielded the largest results.

E.7.3.2 POPULATION SENSITIVITY

The population sensitivity cases (TMI30INC, TMISIT00) demonstrate a significant dependence on population estimates. This is expected given that the population dose and offsite economic costs are primarily driven by the regional population.

In case TMI30INC, the baseline 2034 population is uniformly increased by 30 percent in all sectors of the 50-mile radius. This change increased the estimated population dose-risk and offsite economic cost by over 28 percent each.

A second population based sensitivity (TMISIT00) is performed to determine the impact of using year 2000 census data rather than projecting to the end of the license renewal period (Year 2034). The baseline SAMA case is based on a population projection to year 2034 based on the population growth trends shown between the years 1990 and 2000. When year 2000 data is utilized, the overall dose-risk and OECR decrease, as expected. Specifically, the dose-risk and the OECR decreased by about 29 percent each.

E.7.3.3 EVACUATION SENSITIVITY

The evacuation sensitivity case (TMISLOW) demonstrates population dose-risk impacts associated with evacuation assumptions. While evacuation assumptions do impact the population dose-risk estimates, they do not impact MACCS2 offsite economic cost-risk estimates because MACCS2 calculated cost-risks are based on land contamination levels which remain unaffected by evacuation assumptions and the number of people evacuating.

For Three Mile Island, a slow evacuation assumption is used in the base case (1.18 mph). An additional 50 percent decrease in the evacuation speed to 0.59 mph increased the dose-risk by approximately 15 percent.

E.7.3.4 RADIOACTIVE RELEASE SENSITIVITY

The sensitivity cases TMIATM1 and TMIATM2 quantify the impact of the assumptions related to the height of the release and thermal energy of the plume, respectively. TMIATM1 assumes that the release occurs at ground level rather than at an elevation that could correspond to a release through the stack or a break high in the reactor building. The lower release height shows a decrease in dose-risk and OECR of approximately 5 percent. Reducing the thermal plume heat content to ambient conditions has a minimal impact. TMIATM2 shows an increase in the dose-risk and the OECR of about 1 percent.

E.7.3.5 INTERMEDIATE PHASE DURATION SENSITIVITY

The Intermediate Phase, as modeled by MACCS2, is the time period beginning after the early phase (one week emergency phase) and extends to the time when recovery actions such as decontamination and resettlement are started (long term phase). MACCS2 allows the habitation of land during the intermediate phase unless the projected dose criterion is exceeded. If the projected dose criterion is exceeded during the intermediate phase, the individual is relocated. MACCS2 allows an intermediate phase ranging from no intermediate phase to one (1) year. The Intermediate Phase related sensitivity cases (TMICHR1 and TMICHR2) show significant dependence in relation to economic impact, and are therefore discussed further:

- The No Intermediate Phase case (TMICHR1) is developed based on the NUREG-1150 modeling approach. However, the 37 percent reduction in economic cost estimates based on the approach are judged too optimistic in that the land decontamination efforts are modeled as starting one week after the accident (i.e., directly after the early phase ends) such that a significant portion of population relocation costs are omitted. For example, the costs associated with temporary housing while decontamination strategies are developed and decontamination teams are contracted are not accounted for without an intermediate phase. It is believed that NUREG-1150 studies omitted the intermediate phase because the MACCS2 intermediate phase coding was not validated at that time. A competing factor is that the population dose increases because people are allowed to re-occupy the land sooner (17 percent increase over the base case).

- The 1 Year Intermediate Phase case (TMICHR2) is developed based on the maximum length of time allowed by MACCS2 for the intermediate phase. A long intermediate phase can be unrealistic in that re-occupation of the contaminated land is not performed during this phase even if contamination levels decrease (by natural radioactive decay) to levels which would allow it (i.e., resettlement is evaluated as part of the long term phase, not the intermediate phase). Therefore, population relocation costs may be over estimated using a long (i.e., one year) intermediate phase. An Intermediate Phase of one year shows a 34 percent increase in the OECR estimates compared with the six month (base case) Intermediate phase. However, the population dose decreased by 9 percent with a longer Intermediate Phase due to later resettlement on decontaminated land.

The six month intermediate phase (base case) is judged to be a best estimate approach in that it provides a reasonable time for both decontamination efforts and resettlement to begin. The sensitivity cases demonstrate that this six month modeling approach is mid-range of the modeling choices available and is used as the base case.

E.7.3.6 IMPACT ON SAMA ANALYSIS

Several different Level 3 input parameters are examined as part of the Three Mile Island MACCS2 sensitivity analysis. The primary reason for performing these sensitivity runs is to identify any reasonable changes that could be made to the Level 3 input parameters that would impact the conclusions of the SAMA analysis. While the table in Section E.7.3 summarizes the changes to the dose-risk and OECR estimates for each sensitivity case, it is prudent to consider if any of these changes would result in the retention of the SAMAs that were screened using the baseline results.

Of all the MACCS2 sensitivity cases, the largest increase in the dose-risk is 28 percent in case TMI30INC while the largest increase in OECR is 34 percent in case TMICHR2. While these are separate cases, the Three Mile Island MACR is recalculated using these results to determine the impact of using the worst case for each parameter simultaneously. The resulting MACR is $28,048,743 (a factor of 1.27 increase over the base case), which is less than the $60,739,250 calculated in Section E.7.1 for the 95th percentile PRA results. The 95th percentile PRA results sensitivity is considered to bound this case and no SAMAs would be retained based on this sensitivity that were not already identified in Section E.7.1.

E.7.4 EXTREME FLOODING MITIGATION

The extreme flooding scenario (floods over 310' msl) accounts for 53% of the TMI-1 MACR. While this single sequence is highly important to site risk, the calculation of its CDF is simplified, using only the frequency of a flood exceeding 310' msl (stillwater level) and the failure probability of the severe flood mitigation strategy. In addition, the flooding sequences between 305' and 310' msl contribute a CDF of 1.71E-05/yr and are also based on simplified risk estimates. Typically, simplified estimates such as these include a conservative bias to prevent under predicting negative events; however, due to the large uncertainty in external flood scenarios, it is still possible that the quantification results underestimate the flooding risk. This sensitivity is intended to examine how an optimistic assessment of the flooding risk could impact the SAMA analysis. This sensitivity could be accomplished by modifying the flooding frequency for each of the flood ranges by a set factor, but in this case, the source of uncertainty was assumed to be in the likelihood of successfully implementing the extreme flooding mitigation strategy, which is credited for both floods over 310' msl and those between 305' and 310' msl. SAMA 32 investigates the cost benefit of improving the extreme flooding mitigation strategy, but this sensitivity will provide some insight on how the existing assumptions related to the response capability impact the other SAMA evaluations.

E.7.4.1 PHASE I IMPACT

In this sensitivity, no credit is taken for the use of the current TMI severe flood guidance. This pessimistic assumption changes the extreme flooding CDF from 6.37E-05/yr to 2.50E-04/yr. In addition, the CDFs for all of the sequences in the 305' msl to 310' msl range are increased by a factor of two, which mathematically eliminates the credit taken for the flood guidelines for those sequences. The following table summarizes the changes to the dose-risk and OECR corresponding to these changes in CDF:

Flooding Sensitivity: No Credit for Severe Flooding Guidance

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Base Ext. Flooding Results	8.11E-05	177.16	$542,159
Sensitivity Results	2.84E-04	609.47	$1,864,412
Percent Change	+250.2%	+244.0%	+243.9%

A further breakdown of this information is provided below according to release category.

Flooding Sensitivity: Contributions by Sequence

Flood Category	>310'	305' to 310' sequence A	305' to 310' sequence B	305' to 310' sequence C	305' to 310' sequence D	305' to 310' sequence E	305' to 310' sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
Sensitivity Frequency	2.50E-04	1.26E-05	1.33E-07	1.81E-06	1.22E-05	7.31E-06	1.73E-07	2.50E-07	2.84E-04
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
Sensitivity Dose-Risk	521.00	26.26	0.39	3.77	35.75	21.42	0.51	0.37	609.47
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
Sensitivity OECR	$1,593,214	$80,298	$1,196	$11,535	$109,678	$65,717	$1,555	$1,219	$1,864,412

The corresponding external flooding component of the averted cost-risk is shown below:

Flooding Sensitivity: Revised External Flooding MACR

Base Case External Flooding MACR	Sensitivity Case External Flooding MACR	Difference (Sensitivity MACR - Base MACR)
$15,543,473	$53,604,345	$38,060,872

As can be seen, assuming no credit for TMI's current extreme flood mitigation capabilities results in a large increase in the external flooding MACR ($38,060,872 increase). Given that no SAMAs are screened in the Phase I analysis based on cost, the extreme flooding mitigation capabilities do not impact the Phase I analysis.

E.7.4.2 PHASE II IMPACT

If the same changes are made to the credit taken for the extreme flooding mitigation capabilities for each SAMA (i.e., no credit for the current mitigation strategies), the averted cost-risks are altered for those SAMAs that had some impact on the external flooding risk. The following table summarizes the changes to the cost benefit calculations when no credit is taken for the severe flooding mitigation capabilities:

Results Summary for the Extreme Flooding Capability Sensitivity

SAMA ID	Cost of Implement-ation	Averted Cost- Risk (Base)	Net Value (Base)	Averted Cost- Risk (Sensitivity)	Net Value (Sensitivity)	Change in Cost Effective-ness?
SAMA 1	$3,125,000	$986,145	-$2,138,855	$986,143	-$2,138,857	No
SAMA 2	$7,300,000	$4,297,001	-$3,002,999	$5,206,254	-$2,093,746	No
SAMA 3	$2,450,000	$594,926	-$1,855,074	$601,141	-$1,848,859	No
SAMA 5	$3,150,000	$230,163	-$2,919,837	$230,164	-$2,919,836	No
SAMA 6	$2,750,000	$398,924	-$2,351,076	$405,139	-$2,344,861	No
SAMA 7	$1,000,000	$449,254	-$550,746	$449,256	-$550,744	No
SAMA 8	$145,000	$1,234,676	$1,089,676	$1,234,676	$1,089,676	No
SAMA 10	$3,800,000	$982,048	-$2,817,952	$982,048	-$2,817,952	No
SAMA 11	$4250,000	$16,088,692	$11,838,692	$54,144,650	$49,894,650	No
SAMA 12	$50,000	$198,438	$148,438	$198,438	$148,438	No
SAMA 13	$950,000	$305,294	-$644,706	$305,294	-$644,706	No
SAMA 14	$3,150,000	$603,886	-$2,546,114	$603,888	-$2,546,112	No
SAMA 15	$450,000	$199,098	-$250,902	$200,003	-$249,997	No
SAMA 16	$1,100,000	$1,592,631	$492,631	$1,592,631	$492,631	No
SAMA 17	$950,000	$51,988	-$898,012	$51,988	-$898,012	No
SAMA 18	$100,000	$33,260	-$66,740	$40,379	-$59,621	No
SAMA 19	$760,000	$3,129,354	$2,369,354	$10,098,967	$9,338,967	No
SAMA 20	$3,030,000	$173,974	-$2,856,026	$173,974	-$2,856,026	No
SAMA 21	$1,200,000	$1,181,137	-$18,863	$3,908,256	$2,708,256	Yes
SAMA 22	$5,000,000	$1,253,768	-$3,746,232	$1,253,770	-$3,746,230	No
SAMA 23	$50,000	$30,629	-$19,371	$30,630	-$19,370	No
SAMA 24	$8,400,000	$4,416,201	-$3,983,799	$5,325,454	-$3,074,546	No
SAMA 25	$6,000,000	1,466,139	-$4,533,861	2,375,392	-$3,624,608	No
SAMA 26	$900,000	$369,663	-$530,337	$369,663	-$530,337	No
SAMA 27	$575,000	$1,306,819	$731,819	$1,306,819	$731,819	No
SAMA 28	$575,000	$47,891	-$527,109	$47,891	-$527,109	No
SAMA 29	$800,000	$25,716	-$774,284	$25,716	-$774,284	No
SAMA 30	$150,000	$25,716	-$124,284	$25,716	-$124,284	No
SAMA 32	$1,700,000	$13,052,022	$11,352,022	$51,109,295	$49,409,295	No
SAMA 33	$2,700,000	$9,142,285	$6,442,285	$43,403,546	$40,703,546	No

As demonstrated in the table above, of all the SAMAs evaluated, the "cost effectiveness" classification was only changed for SAMA 21. Given that the 95th percentile PRA results sensitivity presented in Section E.7.1 also identified this SAMA as potentially cost effective, it can be concluded that the results of the SAMA analysis are not impacted by making pessimistic assumptions related to external flooding risk at TMI-1.

E.7.5 SENSITIVITY ANALYSIS: IMPACT OF IMPLEMENTING SAMA 32

While the TMI-1 SAMA list is comprised of unique plant enhancements, it is not uncommon for one SAMA to address areas of risk that are also addressed by one or more other SAMAs. The implication is that implementing a SAMA may impact the net values of the non-implemented SAMAs. Depending on the nature of the SAMAs under consideration, implementation of any given SAMA may result in the reclassification of previously cost beneficial SAMAs as "not cost beneficial". Because SAMA 32 is a potential candidate for implementation at TMI-1, a sensitivity analysis has been performed to evaluate the impact of its implementation on the cost benefit analysis.

Because implementation of SAMA 32 results in a risk decrease, there is no mechanism that would allow a non-cost beneficial SAMA to become cost beneficial; therefore, this sensitivity analysis only addresses the SAMAs that were classified as cost beneficial in either the base case or the 95th percentile PRA results sensitivity case. Specifically, these SAMAs include: 2, 7, 8, 11, 12, 15, 16, 19, 21, 23, 24, 26, 27, and 33.

E.7.5.1 ANALYSIS PROCESS

The intent of this analysis is to quantify the net value of each SAMA assuming that SAMA 32 is already implemented at the site. In order to do this, it was necessary to define the PRA model configuration with SAMA 32 implemented as the new "base case". All model changes made to represent implementation of the other SAMAs were made using the new "base case" as the starting point. This allowed the risk reduction for each SAMA to be measured from the configuration in which SAMA 32 was implemented to the configuration in which SAMA 32 was implemented in conjunction with one additional SAMA.

Establishing SAMA 32 as the "base case" required no changes to the internal events model given that SAMA 32 did not impact internal events risk. Consequently, all of the internal events based risk reductions calculated for the cost beneficial SAMAs were unchanged from the original SAMA analysis. The same was true for the non-external flooding external events contributions given that they were directly derived from the internal events results through the use of a multiplier.

The external flooding results, however, were impacted by SAMA 32 and it was necessary to review the external flooding frequencies for each of the SAMAs and adjust them to account for the impacts of SAMA 32.

For all cases other than for SAMAs 11 and 33, the same quantification strategies described in Section E.6 were used to quantify the external flooding benefits of the SAMAs.

For SAMAs 11 and 33, additional work was required to define how multiple flood mitigation strategies would impact risk. The following table summarizes the assumptions used to perform the quantifications:

Quantification Strategy for Implementation of Multiple Flood Mitigation SAMAs

Case	Floods >310	Floods 305' to 310'	Floods <305'
Implementation of SAMA 32 and SAMA 33	SAMA 33 would be the primary action with SAMA 32 as the backup. It is assumed that the failure probability for installing SAMA 33's extended flood gates is the same as the IPEEE value of 5.62E-02 for the 305' to 310' floods (variable HSL1). Implementation of SAMA 32 is then addressed by a human dependence factor. Non-negligible dependence exists between the actions to install the flood gates and to implement SAMA 32, but the dependence is cognitive. As execution would be the majority contributor to the flood HEPs and because the execution and cognitive contributors are not separated for the flood actions, it would be overly conservative to use the dependence factors based on the available HEPs. To simulate the results of a true assessment, a moderate dependence factor (from equation 10-16 of NUREG/CR-1278 (NRC 1983)) is used rather than a high factor, which would likely be appropriate for the cognitive portion of the HEPs. The failure probability for SAMA 32 is, therefore, 0.14. The CDF for this sequence would be calculated as follows: CDF=2.5E-04*5.62E-02*0.14=1.97E-06	Having higher gates will not impact the installation failure probability significantly. With SAMA 32 implemented, the CDFs should be the same as with SAMA 32 alone.	This SAMA does not impact floods below 305' msl. The CDF should be the same as with SAMA 32 alone.
Implementation of SAMA 32 and SAMA 11	The implementation of SAMA 11 would essentially result in a configuration that would supercede that established by SAMA 32. The CDF for this sequence would be calculated by multiplying the flooding frequency by the failure probability of SAMA 11 (2.05E-02): CDF=2.5E-04*2.05E-02=5.12E-06	The failure probabilities for SAMA 11 are dominated by hardware faults and use of a dependence factor is not required for addressing any potential dependence between installation of the flood panels and operation of SAMA 11. The CDF for these sequences should be obtained by multiplying the sequence CDFs by 2.05E-02. The 0.5 multiplier used in the IPEEE for the existing severe flood guidelines is disregarded and excluded from the calculation.	These sequences would be improved through implementation of SAMA 11. The original CDF, which is the same as the CDF with SAMA 32 implemented, should be multiplied by 2.05E-02.

Finally, the 95th percentile PRA results were used in the quantifications given that they are typically used in the final classification of a SAMA's cost benefit status.

E.7.5.2 RESULTS

The following table summarizes the results of the sensitivity analysis. As shown below, only one SAMA that was originally identified as potentially cost beneficial would be reclassified as "not cost beneficial" if SAMA 32 were implemented at the site (SAMA 21).

Results Summary for the SAMA 32 Implementation Sensitivity

SAMA ID	Cost of Implement-ation	Averted Cost- Risk (95th percentile PRA results)	Net Value (95th percentile PRA results	Averted Cost- Risk (SAMA 32 Implemented, 95th percentile PRA results)	Net Value (SAMA 32 Implemented, 95th percentile PRA results)	Change in Cost Effective-ness?
SAMA 2	$7,300,000	$11,816,753	$4,516,753	$10,016,562	$2,716,562	No
SAMA 7	$1,000,000	$1,235,449	$235,449	$1,235,451	$235,451	No
SAMA 8	$145,000	$3,395,359	$3,250,359	$3,395,359	$3,250,359	No
SAMA 11	$4,250,000	$44,243,903	$39,993,903	$8,339,832	$4,089,832	No
SAMA 12	$50,000	$545,705	$495,705	$545,705	$495,705	No
SAMA 15	$450,000	$547,520	$97,520	$545,562	$95,562	No
SAMA 16	$1,100,000	$4,379,735	$3,279,735	$4,379,738	$3,279,738	No
SAMA 19	$760,000	$8,601,659	$7,841,659	$2,528,235	$1,768,235	No
SAMA 21	$1,200,000	$3,248,127	$2,048,127	$921,330	-$278,670	Yes
SAMA 23	$50,000	$84,230	$34,230	$84,233	$34,233	No
SAMA 24	$8,400,000	$12,144,553	$3,744,553	$10,344,362	$1,944,362	No
SAMA 26	$900,000	$1,016,573	$116,573	$1,016,573	$116,573	No
SAMA 27	$575,000	$3,593,752	$3,018,752	$3,593,752	$3,018,752	No
SAMA 33	$2,700,000	$25,141,284	$22,441,284	$2,839,757	$139,757	No

For SAMAs 2, 11, 19, 21, 24, and 33, the averted cost-risk reductions were all over $1,000,000. A reduction of this magnitude indicates that a large portion of the risk originally intended to be addressed by these SAMAs was removed by SAMA 32 and implementation may not be appropriate. Final judgements related to these SAMAs would likely have to be made using insights outside of the PRA analysis.

The remaining SAMAs (7, 8, 12, 15, 16, 23, 26, and 27) are essentially independent of SAMA 32 and none of their averted cost-risk estimates were impacted by more than 1 percent. No changes to the conclusions related to these SAMAs would be expected based on implementation of SAMA 32.

E.7.6 SENSITIVITY ANALYSIS: IMPACT OF SECPOP ERROR CORRECTIONS

The SECPOP2000 code is used to process population and economic data to serve as input data for the Level 3 PRA code MACCS2 that is used to support SAMA evaluations. The SECPOP2000 code is sponsored by the NRC and is maintained by Sandia National Laboratory.

After completion of the TMI SAMA analysis, three SECPOP errors were identified that if uncorrected, result in MACCS2 utilizing incorrect data thereby impacting the SAMA cost benefit calculations. The TMI SAMA evaluation was not impacted by the first SECPOP error described in this discussion (i.e., Error #1), but the analysis is affected by the second and third errors (Error #2 and Error #3, respectively). All three errors are discussed below for completeness.

E.7.6.1 ERROR #1

In May 2007, a formatting error associated with the SECPOP2000 output file option (which generates a text file for use as an input file to MACCS2) was publicized throughout the industry. The error involves the formatting of the columns in the text file resulting in MACCS2 mis-reading the data. Exelon Risk Management was aware of this formatting error well before its publication throughout the industry. For the TMI SAMA analysis, Risk Management had manually corrected the alignment of the SECPOP2000 output for proper reading by MACCS2. As a result, the TMI SAMA evaluation is not impacted by this error.

E.7.6.2 ERROR #2

In mid-July 2007, an error associated with the formatting of the 1997 economic database file used by SECPOP2000 was discovered by a MACCS2 industry user. This error was discovered when the user attempted to update the database file with new data, and the SECPOP2000 output did not change. Investigation revealed that a formatting error in the database file resulted in SECPOP2000 processing incorrect economic and land use data (i.e., data is output for the wrong counties). The incorrect county selection results in incorrect data being used in MACCS2, ultimately influencing the SAMA cost benefit calculations. The magnitude of the error's impact on the results is different for each site as it depends on the relative difference between the correct county data and incorrect county data read by SECPOP2000, which varies for each county considered. As a result, a site-specific analysis is required to assess the impact on the cost benefit analysis.

E.7.6.3 ERROR #3

In early-August 2007, an additional SECPOP2000 error was identified related to the use of the 1997 economic database file. SECPOP2000 was written to process the county data based on a sequential county numbering system; however, there are gaps in the data file. The first gap appears at county number 955 and any county beyond 955 is handled incorrectly by SECPOP2000. This error was corrected by manipulating the county numbering system in the 1997 economic database file and re-running SECPOP2000.

The nature of Error #3 is similar to Error #2 in that its impact on the cost benefit analysis depends on the relative differences between the correct and incorrect county data. This varies for each county considered and as a result, obtaining an estimate of the impact of the error requires a site specific analysis.

E.7.6.4 IMPACT ON TMI MACR

Review of the TMI SAMA analysis indicates that correcting Error #2 and Error #3 results in a measurable change to both of the MACCS2 outputs that are used to quantify the TMI MACR:

- Dose
- Economic cost

After addressing the errors, the MACCS2 model was re-quantified and the revised results were used to update the MACR calculation. The following tables provide a summary of the corrected results compared with the base case. The designator "PE23" is used to identify the case in which both Error #2 and Error #3 have been corrected.

SECPOP2000 Error Corrections - Internal Events Results Overview

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
Internal Events Results - Base	2.37E-05	32.61	$112,259
Internal Event Results - Post Error Corrections (case PE23)	2.37E-05	32.33	$128,937
Percent Change	0.0%	-0.8%	14.8%

The following tables provide the release category specific results:

Release Category	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
Freq.(/yr)$_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Freq. (/yr)$_{PE23}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
Dose-Risk$_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
Dose-Risk$_{PE23}$	2.62	9.11	0.92	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.02	0.92	4.54	1.02	0.06
OECR$_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208
OECR$_{PE23}$	$14,670	$51,039	$3,873	$272	$4	$4	$8	$13	$398	$149	$87	$3,223	$17,071	$3,835	$242

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
Freq.(/yr)$_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Freq. (/yr)$_{PE23}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
Dose-Risk$_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
Dose-Risk$_{PE23}$	0.00	0.00	0.22	0.04	0.30	0.00	0.99	0.38	6.95	3.42	0.00	0.61	0.00	32.33
OECR$_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259
OECR$_{PE23}$	$3	$0	$880	$157	$981	$12	$3,248	$1,260	$22,904	$3,897	$5	$696	$6	$128,937

Based on these results, the revised non-external flooding cost-risk can be calculated using the methodology from Section E.4 and the 2.0 multiplier on the internal events results:

SECPOP2000 Error Corrections - Non-External Flooding Cost-Risk

PE23 Internal Events Cost-Risk	Non-Flood External Events Multiplier	Non-Ext. Flooding Cost-Risk
$3,514,124	2.0	$7,028,248

Because the Level 3 results are also used in the external flooding evaluation, the impact on the external flooding contribution must also be considered. The following tables summarize the changes to the external flooding results.

SECPOP2000 Error Corrections - External Flooding Results Overview

	CDF (/yr)	Dose-Risk (person-rem/yr)	OECR ($/yr)
External Flooding Results - Base	8.11E-05	177.16	$542,159
External Flooding Results - Post Error Corrections (PE23)	8.11E-05	175.86	$619,814
Percent Change	0.0%	-0.7%	14.3%

A further breakdown of this information is provided below according to flood sequence.

SECPOP2000 Error Corrections - External Flooding Contributions by Flood Sequence

Flood Category	>310'	305' to 310' sequence A	305' to 310' sequence B	305' to 310' sequence C	305' to 310' sequence D	305' to 310' sequence E	305' to 310' sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
Freq. (/yr)$_{PE23}$	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
Dose-Risk$_{PE23}$	131.68	13.02	0.19	1.87	17.81	10.67	0.25	0.37	175.86
Base OECR	$405,951	$40,149	$598	$5,767	$54,839	$32,858	$778	$1,219	$542,159
OECR$_{PE23}$	$464,785	$45,968	$678	$6,603	$62,220	$37,281	$882	$1,397	$619,814

Based on these results, the revised external flooding cost-risk can be calculated using the methodology from Section E.4, which yields $16,672,271. Finally, the revised TMI MACR is the sum of the External Flooding and non-External Flooding contributors:

SECPOP2000 Error Corrections - MACR

PE23 Non-External Flooding Cost-Risk	PE23 External Flooding Cost-Risk	Total MACR (sum of Ext. Flood and Non-Ext. Flood)
$7,028,248	$16,672,271	$23,700,519

Given that the base case MACR was developed by rounding the results of the process documented in Section E.4 to the next highest thousand, the same is done here to obtain a MACR of $23,701,000. This result represents an increase over the base case of 7.3% (($23,701,000-$22,087,000)/ $22,087,000*100=7.3%).

Further investigations revealed that impacts on individual SAMA candidates may differ due to specific release category dependencies (i.e., some release categories may see increases while other release categories see decreases.) Therefore, changes to the averted cost-risk values for each SAMA candidate can not be readily predicted without a SAMA specific re-quantification, which is addressed in Section E.7.6.5.

E.7.6.5 IMPACT ON INDIVIDUAL SAMA CALCULATIONS

In addition to the impact on the MACR, the SECPOP errors also impacted the averted cost-risks and net values that were calculated for each of the SAMAs. The following table summarizes the impact of all SECPOP2000 error corrections (case PE23) in conjunction with the mean PRA results for the detailed cost-benefit calculations that were performed for the SAMA analysis.

Results Summary for SECPOP2000 Corrections (Case PE23, Mean PRA Results)

SAMA ID	Cost of Implement-ation	Averted Cost- Risk (Base)	Net Value (Base)	Averted Cost- Risk (PE23)	Net Value (PE23)	Change in Cost Effective-ness?
SAMA 1	$3,125,000	$986,145	-$2,138,855	$1,039,690	-$2,085,310	No
SAMA 2	$7,300,000	$4,297,001	-$3,002,999	$4,597,411	-$2,702,589	No
SAMA 3	$2,450,000	$594,926	-$1,855,074	$624,045	-$1,825,955	No
SAMA 5	$3,150,000	$230,163	-$2,919,837	$240,738	-$2,909,262	No
SAMA 6	$2,750,000	$398,924	-$2,351,076	$412,415	-$2,337,585	No
SAMA 7	$1,000,000	$449,254	-$550,746	$467,015	-$532,985	No
SAMA 8	$145,000	$1,234,676	$1,089,676	$1,318,032	$1,173,032	No
SAMA 10	$3,800,000	$982,048	-$2,817,952	$1,086,512	-$2,713,488	No
SAMA 11	$4250,000	$16,088,692	$11,838,692	$17,237,942	$12,987,942	No
SAMA 12	$50,000	$198,438	$148,438	$210,304	$160,304	No
SAMA 13	$950,000	$305,294	-$644,706	$333,154	-$616,846	No
SAMA 14	$3,150,000	$603,886	-$2,546,114	$630,447	-$2,519,553	No
SAMA 15	$450,000	$199,098	-$250,902	$209,632	-$240,368	No
SAMA 16	$1,100,000	$1,592,631	$492,631	$1,745,154	$645,154	No
SAMA 17	$950,000	$51,988	-$898,012	$55,242	-$894,758	No
SAMA 18	$100,000	$33,260	-$66,740	$32,229	-$67,771	No
SAMA 19	$760,000	$3,127,876	$2,367,876	$3,415,704	$2,655,704	No
SAMA 20	$3,030,000	$173,974	-$2,856,026	$189,934	-$2,840,066	No
SAMA 21	$1,200,000	$1,181,137	-$18,863	$1,292,074	$92,074	Yes
SAMA 22	$5,000,000	$1,253,768	-$3,746,232	$1,380,631	-$3,619,369	No
SAMA 23	$50,000	$30,629	-$19,371	$32,220	-$17,780	No
SAMA 24	$8,400,000	$4,416,201	-$3,983,799	$4,730,523	-$3,669,477	No
SAMA 25	$6,000,000	1,466,139	-$4,533,861	1,574,565	-$4,425,435	No
SAMA 26	$900,000	$369,663	-$530,337	$397,053	-$502,947	No
SAMA 27	$575,000	$1,306,819	$731,819	$1,403,645	$828,645	No
SAMA 28	$575,000	$47,891	-$527,109	$51,440	-$523,560	No
SAMA 29	$800,000	$25,716	-$774,284	$27,621	-$772,379	No
SAMA 30	$150,000	$25,716	-$124,284	$27,621	-$122,379	No
SAMA 32	$1,700,000	$13,052,022	$11,352,022	$14,000,044	$12,300,044	No
SAMA 33	$2,700,000	$9,142,285	$6,442,285	$9,807,683	$7,107,683	No

As demonstrated in the table, the SECPOP2000 error corrections had a relatively small impact on the averted cost-risk estimates and only one SAMA (SAMA 21) that was originally classified as “not cost beneficial” was re-classified as “cost beneficial” based on the use of the corrected input. Given that SAMA 21 was identified as potentially cost beneficial in the 95th percentile

PRA results sensitivity analysis that is documented in Section E.7.1, this change did not result in the identification of any new potentially cost beneficial SAMAs.

In addition to the review of the mean PRA results quantifications, it was necessary to examine how the 95th percentile PRA results quantifications were impacted given that they were also used to identify potentially cost beneficial SAMAs. The following table provides a summary of the cost benefit calculations using the results of the SECPOP2000 error corrections in conjunction with the 95th percentile PRA results. In this case, no SAMAs were identified as potentially cost beneficial that were not already identified in original 95th percentile PRA results sensitivity analysis documented in Section E.7.1.

Results Summary for SECPOP2000 Corrections (Case PE23, 95th Percentile PRA Results)

SAMA ID	Cost of Implement-ation	Averted Cost- Risk (Original 95th Percentile Results)	Net Value (Original 95th Percentile Results)	Averted Cost- Risk (PE23 with 95th Percentile Results)	Net Value (PE23 with 95th Percentile Results)	Change in Cost Effective-ness?
SAMA 1	$3,125,000	$2,711,899	-$413,101	$2,859,148	-$265,853	No
SAMA 2	$7,300,000	$11,816,753	$4,516,753	$12,642,880	$5,342,880	No
SAMA 3	$2,450,000	$1,636,047	-$813,954	$1,716,124	-$733,876	No
SAMA 5	$3,150,000	$632,948	-$2,517,052	$662,030	-$2,487,971	No
SAMA 6	$2,750,000	$1,097,041	-$1,652,959	$1,134,141	-$1,615,859	No
SAMA 7	$1,000,000	$1,235,449	$235,449	$1,284,291	$284,291	No
SAMA 8	$145,000	$3,395,359	$3,250,359	$3,624,588	$3,479,588	No
SAMA 10	$3,800,000	$2,700,632	-$1,099,368	$2,987,908	-$812,092	No
SAMA 11	$4250,000	$44,243,903	$39,993,903	$47,404,341	$43,154,341	No
SAMA 12	$50,000	$545,705	$495,705	$578,336	$528,336	No
SAMA 13	$950,000	$839,559	-$110,442	$916,174	-$33,827	No
SAMA 14	$3,150,000	$1,660,687	-$1,489,314	$1,733,729	-$1,416,271	No
SAMA 15	$450,000	$547,520	$97,520	$576,488	$126,488	No
SAMA 16	$1,100,000	$4,379,735	$3,279,735	$4,799,174	$3,699,174	No
SAMA 17	$950,000	$142,967	-$807,033	$151,916	-$798,085	No
SAMA 18	$100,000	$91,465	-$8,535	$88,630	-$11,370	No
SAMA 19	$760,000	$8,601,659	$7,841,659	$9,393,186	$8,633,186	No
SAMA 20	$3,030,000	$478,429	-$2,551,572	$522,319	-$2,507,682	No
SAMA 21	$1,200,000	$3,248,127	$2,048,127	$3,553,204	$2,353,204	No
SAMA 22	$5,000,000	$3,447,862	-$1,552,138	$3,796,735	-$1,203,265	No
SAMA 23	$50,000	$84,230	$34,230	$88,605	$38,605	No
SAMA 24	$8,400,000	$12,144,553	$3,744,553	$13,008,938	$4,608,938	No
SAMA 25	$6,000,000	$4,031,882	-$1,968,118	$4,330,055	-$1,669,945	No

Results Summary for SECPOP2000 Corrections (Case PE23, 95th Percentile PRA Results)

SAMA ID	Cost of Implement-ation	Averted Cost- Risk (Original 95th Percentile Results)	Net Value (Original 95th Percentile Results)	Averted Cost- Risk (PE23 with 95th Percentile Results)	Net Value (PE23 with 95th Percentile Results)	Change in Cost Effective-ness?
SAMA 26	$900,000	$1,016,573	$116,573	$1,091,894	$191,894	No
SAMA 27	$575,000	$3,593,752	$3,018,752	$3,860,024	$3,285,024	No
SAMA 28	$575,000	$131,701	-$443,299	$141,459	-$433,541	No
SAMA 29	$800,000	$70,719	-$729,281	$75,958	-$724,042	No
SAMA 30	$150,000	$70,719	-$79,281	$75,958	-$74,042	No
SAMA 32	$1,700,000	$35,893,061	$34,193,061	$38,500,121	$36,800,121	No
SAMA 33	$2,700,000	$25,141,284	$22,441,284	$26,971,128	$24,271,128	No

E.8 CONCLUSIONS

The benefits of revising the operational strategies in place at TMI-1 and/or implementing hardware modifications can be evaluated without the insight from a risk analysis. Use of the PRA in conjunction with cost-benefit analysis methodologies has, however, provided an enhanced understanding of the effects of the proposed changes relative to the cost of implementation and projected impact on offsite dose and economic impacts. The results of this study indicate that of the identified potential improvements that can be made at TMI-1, several are cost beneficial based on the methodology applied in this analysis.

The baseline Phase II analysis indicates that the following SAMAs are potentially cost beneficial:

- SAMA 8: Automate Reactor Coolant Pump Trip (on high motor bearing temperature)
- SAMA 11: Enhance Extreme External Flooding Mitigation Equipment to Address SBO and Loss of Seal Cooling Scenarios
- SAMA 12: Use the DHR System as an Alternate Suction Source for HPI
- SAMA 16: Automate HPI Injection on Low Pressurizer Level
- SAMA 19: Install Battery Backed Hydrogen Igniters or a Passive Hydrogen Ignition System
- SAMA 27: Improve the 480V AC load center welds
- SAMA 32: Pre-stage Severe Flooding Equipment
- SAMA 33: Increase the Flood Protection Height

In addition, when the 95th percentile PRA results are used in the analysis, the following additional SAMAs are potentially cost beneficial:

- SAMA 2: Install Damage Resistant, High Temperature RCP Seals with a Portable 480V Generator for Extended EFW Operation
- SAMA 7: Use Fire Service Water as an Alternate Cooling Source for the ICCW Heat Exchangers

- SAMA 15: Automate Swap to Recirculation Mode
- SAMA 21: Install Concrete Shields to Block Direct Pathways from the RPV to the Containment Wall and/or Direct Containment Flooding Early in External Flooding Scenarios
- SAMA 23: Develop Alarm Response Procedures to Direct Operation of RR-V-5 on Low RBEC Flow
- SAMA 24: Install Damage Resistant, High Temperature RCP Seals with a Diesel Engine as an Alternate Drive for an EFW Pump and a Portable Generator for Level Control Instrumentation
- SAMA 26: Reroute Cables so that They Do Not Pass Over Ignition Sources in Fire Area CB-FA-2e (West Inverter Room) or Wrap them in Fire Proof Material

While the identification of a SAMA as potentially “cost beneficial” indicates that it may be advantageous to implement the SAMAs from a PRA based risk reduction perspective, not all of the SAMAs should be designated as serious candidates for implementation. Some of the SAMAs address the same types of risk such that implementation of a given SAMA would significantly reduce or eliminate the benefit of another SAMA. In addition, there are differences in the level of uncertainty in the PRA bases that support the SAMA cost benefit calculations. While a particular SAMA may show a large potential risk reduction, it would be inappropriate to justify the expenditure of a large sum of money to address a risk that is likely overstated by pessimistic PRA assumptions or technical limitations. Table E.8.1 summarizes these considerations for the SAMAs that have been identified as potentially cost beneficial for TMI-1. In addition, this table provides the following information:

- The implementation cost for the SAMA
- Averted cost-risk (based on the 95th percentile PRA results),
- Net value (based on the 95th percentile PRA results), and
- The ratio of the averted cost-risk per dollar of implementation cost (identified as the “dollar per dollar” (DPD) ratio).

E.9 FIGURES

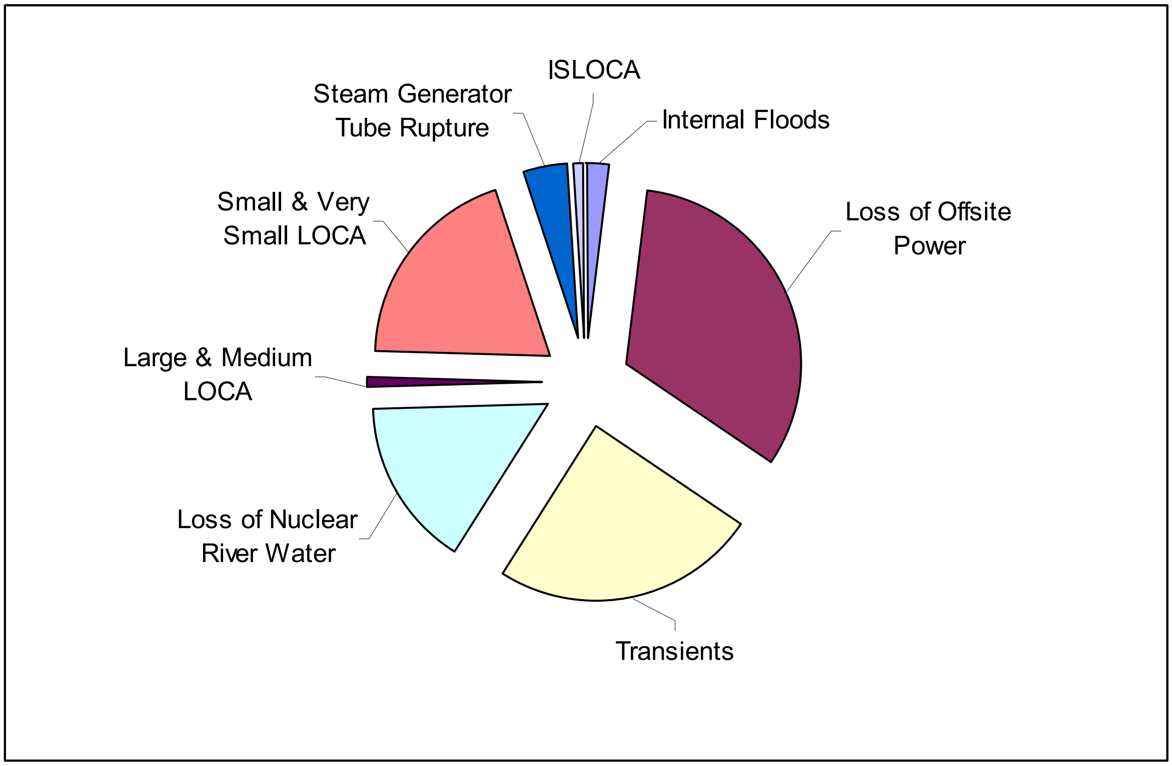


Figure E.2-1
TMI-1 Level 1 CDF Contributions

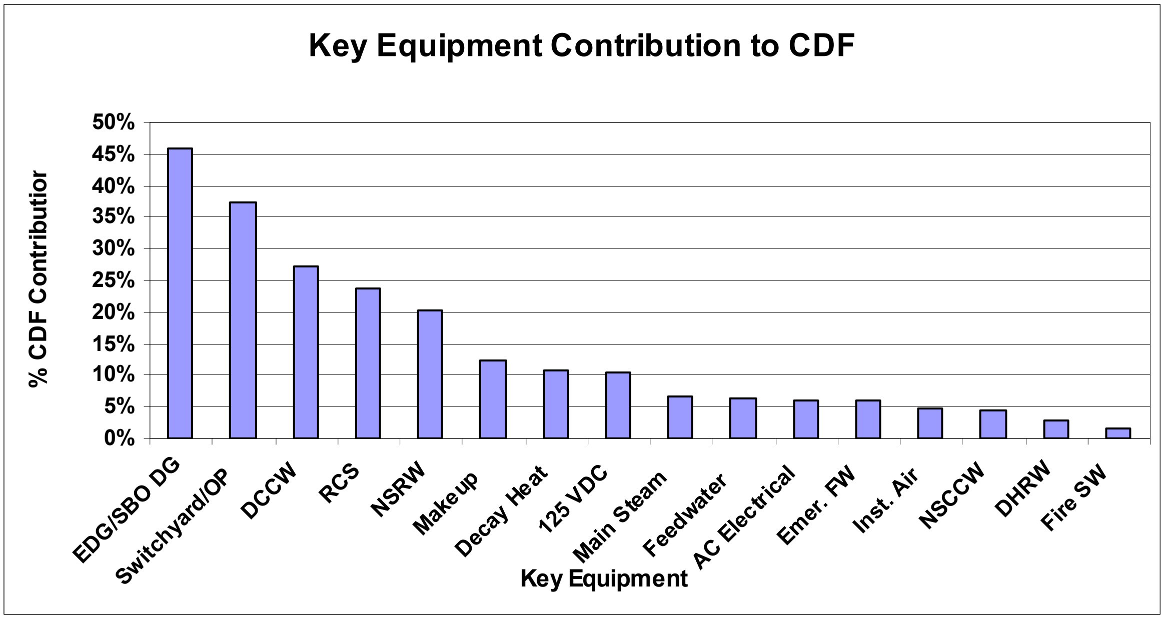


Figure E.2-2
TMI-1 System Importance Rankings

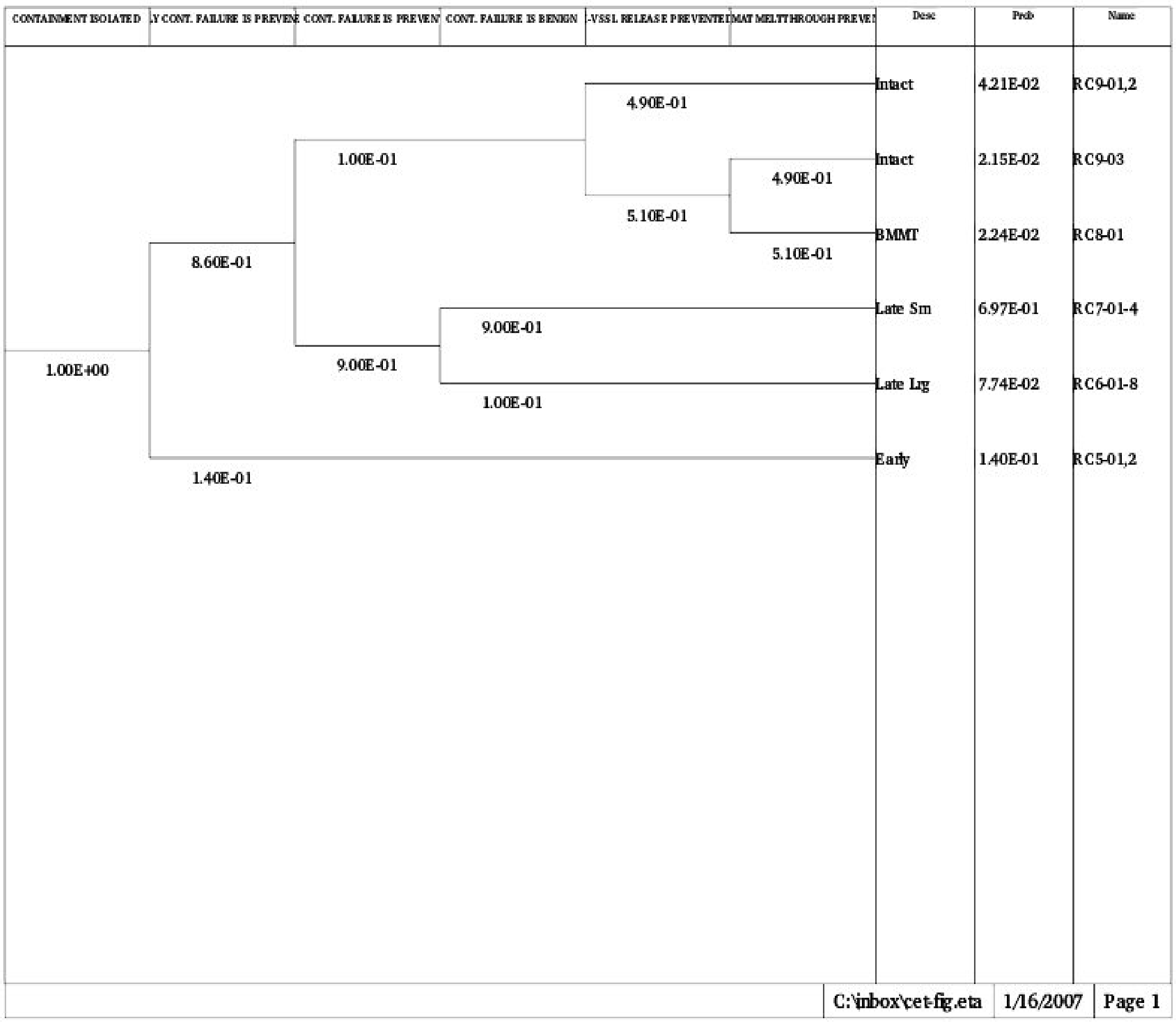


Figure E.2-3
Simplified CET Binning Logic for External Flooding Analysis

E.10 TABLES

TABLE E.2-1
THREE MILE ISLAND PRA MODEL SUMMARY

Model Revision Date	Model Name	Internal Events Excluding Internal Flooding (1/yr)	Seismic (1/yr)	Internal Flooding (1/yr)	Total CDF (1/yr)	Total LERF (1/yr)	Trunc. Limit (1/yr)	Notes
Nov. 1987	Original PRA	4.43E-4	2.70E-6	<1.0E-5	5.5E-4	NA	NR	1
Dec. 1992	IPE	4.19E-5	-	-	4.19E-5	NA	NR	2
Dec. 1994	IPEEE Update	-	3.21E-5	-	-	NA	-	3
Aug. 2000	2000 Update	3.74E-5	-	3.0E-06	4.1E-5	3.75E-6	NR	4
Nov. 2001	L2RV2	3.69E-5	-	2.56E-6	3.95E-5	2.70E-6	1E-12	5
Jul. 2003	ABSA	3.33E-5	-	3.5E-7	3.38E-5	1.39E-6	1E-14	6
Dec. 2004	2004 Rev. 0	3.07E-5	-	2.6E-7	3.09E-5	-	1E-11	7
Jun. 2005	2004 Rev. 1	3.32E-5	-	3.7E-7	3.36E-5	-	1E-11	8
June 2007	2004 Rev. 2	2.32E-5	-	4.5E-7	2.37E-5	3.02E-06	1E-11	9

Notes:

1. Original PRA for Three Mile Island Unit 1; Truncation limit not reported (NR). All sequences quantified but some are grouped with more severe support states. LERF not computed.
2. 1992 update for the IPE. Control building ventilation failures deleted from model based on physical testing of the system and rooms served. Truncation limit not reported. LERF not computed.
3. IPEEE update. Seismic results not modified since this report.
4. TMI RISKMAN® 2000 Update; Level 2 added to model for first time. Truncation limit not reported. Model reflects plant design as of 1998 (see Reference [9]).
5. TMI RISKMAN® L2RV2 model: Level 2 model directly linked with Level 1 sequences.
6. TMI RISKMAN® ABSA model: Revisions in support of responses to peer certification comments. Plant model reflects plant design as of January, 2003 (see Reference [8]).
7. TMI CAFTA® 2004, Rev. 0 model: Initial conversion of ABSA Level 1 model from RISKMAN® to CAFTA® software. This model was never officially implemented. Level 2 model not revised.
8. TMI CAFTA® 2004, Rev. 1 model: Implementation of various model changes and improvements since Revision 0 (see Reference [4]). Level 2 model not revised.
9. TMI CAFTA® 2004, Rev. 2 model: Implementation of various model changes and improvements since Revision 1 (see Reference [5]). New Level 2 model (see Reference [6]) developed using CAFTA® based on February 1993 Level 2 model (see Reference [3]).

TABLE E.2-2
CORE MELT BINS

BIN #	DESCRIPTION
1	Large LOCA, injection failure
2	Large LOCA, early recirculation failure
3	Large LOCA, late recirculation failure
4	Medium LOCA, injection failure
5	Medium LOCA, early recirculation failure
6	Medium LOCA, late recirculation failure
7	Small LOCA, injection failure, steam generators available
8	Small LOCA, recirculation failure, steam generators available
9	Small LOCA, injection failure, steam generators unavailable
10	Small LOCA, early recirculation failure, steam generators unavailable
11	Small LOCA, late recirculation failure, steam generators unavailable
12	Cycling relief valve, injection failure
13	Cycling relief valve, early recirculation failure
14	Cycling relief valve, late recirculation failure
15	Steam generator tube rupture, injection failure, steam generators unavailable
16	Steam generator tube rupture, early recirculation failure, steam generators unavailable
17	Steam generator tube rupture, late recirculation failure, steam generators unavailable
18	Steam generator tube rupture, steam generators available
19	Interfacing-systems LOCA

TABLE E.2-3
CORE MELT BIN ASSIGNMENTS FOR LEVEL 1 TRANSIENT CORE DAMAGE STATES

SEQUENCE ID [6]	CORE MELT ASSIGNMENTS FROM TABLE E.2-2	COMMENTS
GT-004	13 or 14	Depending on time of recirculation failure.
GT-005	2	Based on PTS failures assuming to be a part of this core melt bin.
GT-006	12	

TABLE E.2-4
CORE MELT BIN ASSIGNMENTS FOR LEVEL 1
LOOP-SBO CORE DAMAGE STATES

SEQUENCE ID [6]	CORE MELT ASSIGNMENTS FROM TABLE E.2-2	COMMENTS
LOOP-002	2	Based on PTS failures assuming to be a part of this core melt bin.
LOOP-004	13 or 14	Depending on time of recirculation failure.
LOOP-005	12	
LOOP-006	2	Based on PTS failures assuming to be a part of this core melt bin.
LOOP-009	8	
LOOP-011	7	
LOOP-012	2	Based on PTS failures assuming to be a part of this core melt bin.
LOOP-014	10 or 11	Depending on time of recirculation failure.
LOOP-015	9	
LOOP-016	2	Based on PTS failures assuming to be a part of this core melt bin.
LOOP-018	2	Based on PTS failures assuming to be a part of this core melt bin.
LOOP-021	13 or 14	Depending on time of recirculation failure.
LOOP-022	12	
LOOP-023	2	Based on PTS failures assuming to be a part of this core melt bin.
LOOP-025	13 or 14	Depending on time of recirculation failure.
LOOP-026	12	
LOOP-027	2	Based on PTS failures assuming to be a part of this core melt bin.
LOOP-030	8	
LOOP-032	7	
LOOP-033	2	Based on PTS failures assuming to be a part of this core melt bin.
LOOP-036	8	
LOOP-038	7	
LOOP-039	2	Based on PTS failures assuming to be a part of this core melt bin.
LOOP-042	8	
LOOP-044	7	
LOOP-046	10 or 11	Depending on time of recirculation failure.
LOOP-047	9	
LOOP-048	2	Based on PTS failures assuming to be a part of this core melt bin.
LOOP-050	10 or 11	Depending on time of recirculation failure.
LOOP-051	9	

TABLE E.2-4
CORE MELT BIN ASSIGNMENTS FOR LEVEL 1 LOOP-SBO CORE DAMAGE STATES

SEQUENCE ID [6]	CORE MELT ASSIGNMENTS FROM TABLE E.2-2	COMMENTS
LOOP-052	2	Based on PTS failures assuming to be a part of this core melt bin.
LOOP-055	8	
LOOP-057	7	
LOOP-058	2	Based on PTS failures assuming to be a part of this core melt bin.
LOOP-059	7	
LOOP-062	8	
LOOP-064	7	
LOOP-066	10 or 11	Depending on time of recirculation failure.
LOOP-067	9	
LOOP-068	2	Based on PTS failures assuming to be a part of this core melt bin.
LOOP-069	9	

TABLE E.2-5
CORE MELT BIN ASSIGNMENTS FOR LEVEL 1 VERY SMALL LOCA CORE DAMAGE STATES

SEQUENCE ID [6]	CORE MELT ASSIGNMENTS FROM TABLE E.2-2	COMMENTS
VSL-004	8	Conservatively binned since depressurization was successful
VSL-006	8	
VSL-007	2	Based on PTS failures assuming to be a part of this core melt bin.
VSL-011	8	Conservatively binned since depressurization was successful
VSL-013	8	
VSL-014	2	Based on PTS failures assuming to be a part of this core melt bin.
VSL-016	10 or 11	Depending on time of recirculation failure.
VSL-017	2	Based on PTS failures assuming to be a part of this core melt bin.
VSL-018	10	
VSL-019	9	SSHR is assumed unavailable.

TABLE E.2-6
CORE MELT BIN ASSIGNMENTS FOR LEVEL 1 SMALL LOCA CORE DAMAGE STATES

SEQUENCE ID [6]	CORE MELT ASSIGNMENTS FROM TABLE E.2-2	COMMENTS
SL-002	10 or 11	Depending on time of recirculation failure. SSHR is assumed unavailable.
SL-003	2	Based on PTS failures assuming to be a part of this core melt bin.
SL-005	8	
SL-006	2	Based on PTS failures assuming to be a part of this core melt bin.
SL-008	8	
SL-009	2	Based on PTS failures assuming to be a part of this core melt bin.
SL-010	10	Failure of early recirculation is assumed.
SL-011	9	SSHR is assumed unavailable.

TABLE E.2-7
CORE MELT BIN ASSIGNMENTS FOR LEVEL 1 MEDIUM LOCA CORE DAMAGE STATES

SEQUENCE ID [6]	CORE MELT ASSIGNMENTS FROM TABLE E.2-2	COMMENTS
ML-002	5 or 6	Depending on time of recirculation failure.
ML-003	4	Injection failure is assumed, even though partial injection was successful.
ML-004	4	

TABLE E.2-8
CORE MELT BIN ASSIGNMENTS FOR LEVEL 1 LARGE LOCA CORE DAMAGE STATES

SEQUENCE ID [6]	CORE MELT ASSIGNMENTS FROM TABLE E.2-2	COMMENTS
LL-002	2 or 3	Depending on time of recirculation failure.
LL-003	1	Injection failure is assumed, even though partial injection was successful.
LL-004	1	

TABLE E.2-9
CORE MELT BIN ASSIGNMENTS FOR LEVEL 1 SGTR CORE DAMAGE STATES

SEQUENCE ID [6]	CORE MELT ASSIGNMENTS FROM TABLE E.2-2	COMMENTS
SGTR-004	18	
SGTR-006	18	
SGTR-010	18	
SGTR-012	18	
SGTR-013	16	Since SSHR is unavailable, water is assumed to be present in containment due to primary pressure relief.
SGTR-014	16	SSHR is assumed unavailable.
SGTR-015	15	SSHR is assumed unavailable.

TABLE E.2-10
CORE MELT BIN ASSIGNMENTS FOR LEVEL 1 STEAMLINE BREAKS UPSTREAM MSIVS CORE DAMAGE STATES

SEQUENCE ID [6]	CORE MELT ASSIGNMENTS FROM TABLE E.2-2	COMMENTS
SLBI-003	13 or 14	Depending on time of recirculation failure.
SLBI-004	13	Conservative assumption due to failure of pressure relief.
SLBI-005	12	
SLBI-007	10 or 11	Depending on time of recirculation failure. SSHR is assumed unavailable.
SLBI-008	9	SSHR is assumed unavailable.
SLBI-010	13 or 14	Depending on time of recirculation failure.
SLBI-011	13	Conservative assumption due to failure of pressure relief.
SLBI-012	2	Based on PTS failures assuming to be a part of this core melt bin.
SLBI-013	12	

TABLE E.2-11
CORE MELT BIN ASSIGNMENTS FOR LEVEL 1 STEAMLINE BREAKS DOWNSTREAM MSIVS CORE DAMAGE STATES

SEQUENCE ID [6]	CORE MELT ASSIGNMENTS FROM TABLE E.2-2	COMMENTS
SLBO-004	13 or 14	Depending on time of recirculation failure.
SLBO-005	13	Conservative assumption due to failure of pressure relief.
SLBO-006	2	Based on PTS failures assuming to be a part of this core melt bin.
SLBO-007	12	
SLBO-009	10 or 11	Depending on time of recirculation failure. SSHR is assumed unavailable.
SLBO-010	2	Based on PTS failures assuming to be a part of this core melt bin.
SLBO-011	9	SSHR is assumed unavailable.

TABLE E.2-12
CORE MELT BIN ASSIGNMENTS FOR LEVEL 1 ATWS CORE DAMAGE STATES

SEQUENCE ID [6]	CORE MELT ASSIGNMENTS FROM TABLE E.2-2	COMMENTS
ATWS-002	14	Least conservative bin, since core damage may not result for this sequence.
ATWS-003	12	
ATWS-005	14	Least conservative bin, since core damage may not result for this sequence.
ATWS-006	12	
ATWS-007	12	Failure of injection is assumed
ATWS-008	12	Failure of injection is assumed
ATWS-009	1	Injection is assumed ineffective
ATWS-010	1	Injection is assumed ineffective

TABLE E.2-13
CORE MELT BIN ASSIGNMENTS FOR LEVEL 1 ISLOCA CORE DAMAGE STATES

SEQUENCE ID [6]	CORE MELT ASSIGNMENTS FROM TABLE E.2-2	COMMENTS
ISLOC-001	19	

TABLE E.2-14
CONTAINMENT SAFEGUARDS/ISOLATION STATE

STATE ID	DESCRIPTION
A	All safeguards available, containment isolated
B	Fans available, sprays available in injection mode; sprays unavailable in recirculation mode, containment isolated
C	Fans available; sprays unavailable in injection and recirculation modes, containment isolated
D	Sprays available in injection and recirculation modes; fans unavailable, containment isolated
E	Sprays in injection mode available; fans unavailable, sprays unavailable in recirculation mode, containment isolated
F	No safeguards available, containment isolated
G	All safeguards available, small isolation failure
H	Fans available, sprays available in injection mode; sprays unavailable in recirculation mode, small isolation failure
I	Fans available; sprays unavailable in injection and recirculation modes, small isolation failure
J	Sprays available in injection and recirculation modes; fans unavailable, small isolation failure
K	Sprays in injection mode available; fans unavailable, sprays unavailable in recirculation mode, small isolation failure
L	No safeguards available, small isolation failure
M	All safeguards available, large isolation failure
N	Fans available, sprays available in injection mode; sprays unavailable in recirculation mode, large isolation failure
O	Fans available; sprays unavailable in injection and recirculation modes, large isolation failure
P	Sprays available in injection and recirculation modes; fans unavailable, large isolation failure
Q	Sprays in injection mode available; fans unavailable, sprays unavailable in recirculation mode, large isolation failure
R	No safeguards available, large isolation failure

TABLE E.2-15
CONTAINMENT EVENT TREE TOP EVENTS

EVENT NODE/STATE	DESCRIPTION
A	**Containment Bypass**
Success	Containment is available as a barrier to fission product release
Failure	Containment is not available as a barrier to fission product release (SGTR, ISLOCA)
B	**Containment Isolation**
Success	Containment is isolated
Failure	Containment is not isolated
C	**Large Isolation Failure**
Success	Isolation failure is small
Failure	Isolation failure is large
D	**Auxiliary Building Release**
Success	Fission product release is through the Auxiliary Building
Failure	Fission product release does not go through the Auxiliary Building
E	**Early Containment Failure**
Success	Early containment failure does not take place
Failure	Early containment failure does occur
F	**Late Containment Failure**
Success	Late containment failure does not take place
Failure	Late containment failure does occur
G	**Benign Containment Failure**
Success	Containment failure is benign, i.e., leak before break
Failure	Containment failure is catastrophic
H	**Ex-Vessel Release of Fission Products**
Success	Ex-vessel release is prevented
Failure	Ex-vessel release is not prevented
I	**Containment Basemat Failure**
Success	Containment failure from basemat melt-through is prevented
Failure	Containment failure from basemat melt-through occurs
J	**Revaporization Release**
Success	Revaporization release does not take place
Failure	Revaporization release does occur
K	**Fission Product Scrubbing**
Success	Fission products are scrubbed in containment, steam generator, or Auxiliary Building
Failure	Fission products are not scrubbed

TABLE E.2-16
INDIVIDUAL RELEASE CATEGORY DEFINITIONS

RELEASE CATEGORY	DEFINITION	BASELINE FREQUENCY (/YR)
1.01	Containment bypass, outside the auxiliary building, with fission product scrubbing, release begins at approximately 4 hrs	4.57E-07
1.02	Containment bypass, outside the auxiliary building, without fission product scrubbing, release begins at approximately 3 hrs	1.59E-06
2.01	Containment bypass, to the auxiliary building, without ex-vessel release of fission products, with fission product scrubbing, release begins at approximately 4 hrs	0.0
2.02	Containment bypass, to the auxiliary building, without ex-vessel release of fission products, without fission product scrubbing, release begins at approximately 3 hrs	1.81E-07
2.03	Containment bypass, to the auxiliary building, with ex-vessel release of fission products, with fission product scrubbing, release begins at approximately 4 hrs	0.0
2.04	Containment bypass, to the auxiliary building, with ex-vessel release of fission products, without fission product scrubbing, release begins at approximately 3 hrs	1.27E-08
3.01	Large isolation failure, to the auxiliary building, without ex-vessel release of fission products, with fission product scrubbing, release begins at approximately 1.5 hrs	9.07E-11
3.02	Large isolation failure, to the auxiliary building, without ex-vessel release of fission products, without fission product scrubbing, release begins at approximately 1.5 hrs	9.07E-11
3.03	Large isolation failure, to the auxiliary building, with ex-vessel release of fission products, with fission product scrubbing, release begins at approximately 1.5 hrs	1.90E-10
3.04	Large isolation failure, to the auxiliary building, with ex-vessel release of fission products, without fission product scrubbing, release begins at approximately 1.5 hrs	2.88E-10
3.05	Large isolation failure, outside the auxiliary building, without ex-vessel release of fission products, release begins at approximately 1.5 hrs	0.0
3.06	Large isolation failure, outside the auxiliary building, with ex-vessel release of fission products, release begins at approximately 1.5 hrs	0.0
4.01	Small isolation failure, to the auxiliary building, without ex-vessel release of fission products, with fission product scrubbing, release begins at approximately 2.5 hrs	3.90E-08
4.02	Small isolation failure, to the auxiliary building, without ex-vessel release of fission products, without fission product scrubbing, release begins at approximately 2.5 hrs	1.46E-08

TABLE E.2-16
INDIVIDUAL RELEASE CATEGORY DEFINITIONS

RELEASE CATEGORY	DEFINITION	BASELINE FREQUENCY (/YR)
4.03	Small isolation failure, to the auxiliary building, with ex-vessel release of fission products, with fission product scrubbing, release begins at approximately 2.5 hrs	8.54E-09
4.04	Small isolation failure, to the auxiliary building, with ex-vessel release of fission products, without fission product scrubbing, release begins at approximately 2.5 hrs	3.16E-07
4.05	Small isolation failure, to the environment, without ex-vessel release of fission products, with fission product scrubbing, release begins at approximately 2.5 hrs	0.0
4.06	Small isolation failure, to the environment, without ex-vessel release of fission products, without fission product scrubbing, release begins at approximately 2.5 hrs	0.0
4.07	Small isolation failure, to the environment, with ex-vessel release of fission products, without fission product scrubbing, release begins at approximately 2.5 hrs	0.0
4.08	Small isolation failure, to the environment, with ex-vessel release of fission products, without fission product scrubbing, release begins at approximately 2.5 hrs	0.0
5.01	Early containment failure, without ex-vessel fission product release, release begins at approximately 3.25 hrs	7.39E-07
5.02	Early containment failure, with ex-vessel fission product release, release begins at approximately 5.5 hrs	1.66E-07
6.01	Late overpressurization, with catastrophic containment failure, without ex-vessel fission product release, without revaporization, with fission product scrubbing, release begins at approximately 45 hrs	0.0
6.02	Late overpressurization, with catastrophic containment failure, without ex-vessel fission product release, without revaporization, without fission product scrubbing, release begins at approximately 45 hrs	0.0
6.03	Late overpressurization, with catastrophic containment failure, without ex-vessel fission product release, with revaporization, with fission product scrubbing, release begins at approximately 45 hrs	2.20E-08
6.04	Late overpressurization, with catastrophic containment failure, without ex-vessel fission product release, with revaporization, without fission product scrubbing, release begins at approximately 45 hrs	2.36E-10
6.05	Late overpressurization, with catastrophic containment failure, with ex-vessel release of fission products, without revaporization, with fission product scrubbing, release begins at approximately 45 hrs	2.08E-11
6.06	Late overpressurization, with catastrophic containment failure, with ex-vessel release of fission products, without revaporization, without fission product scrubbing, release begins at approximately 45 hrs	0.0

TABLE E.2-16
INDIVIDUAL RELEASE CATEGORY DEFINITIONS

RELEASE CATEGORY	DEFINITION	BASELINE FREQUENCY (/YR)
6.07	Late overpressurization, with catastrophic containment failure, with ex-vessel release of fission products, with revaporization, with fission product scrubbing, release begins at approximately 45 hrs	8.00E-08
6.08	Late overpressurization, with catastrophic containment failure, with ex-vessel release of fission products, with revaporization, without fission product scrubbing, release begins at approximately 45 hrs	1.43E-08
7.01	Late overpressurization, with benign containment failure, without ex-vessel fission product release, with fission product scrubbing, release begins at approximately 14.5 hrs	2.25E-07
7.02	Late overpressurization, with benign containment failure, without ex-vessel fission product release, without fission product scrubbing, release begins at approximately 14.5 hrs	2.75E-09
7.03	Late overpressurization, with benign containment failure, with ex-vessel release of fission products, with fission product scrubbing, release begins at approximately 14.5 hrs	7.45E-07
7.04	Late overpressurization, with benign containment failure, with ex-vessel release of fission products, without fission product scrubbing, release begins at approximately 14.5 hrs	7.89E-07
8.01	Containment failure from basemat melt-through, with ex-vessel release of fission products, release begins at approximately 36 hrs	3.19E-06
9.01	No containment failure, without ex-vessel fission product release, with fission product scrubbing, release begins at approximately 0.5 hrs	1.32E-05
9.02	No containment failure, without ex-vessel fission product release, without fission product scrubbing, release begins at approximately 2.5 hrs	1.69E-08
9.03	No containment failure, with ex-vessel fission product release, with fission product scrubbing, release begins at approximately 2.5 hrs	2.36E-06
9.04	No containment failure, with ex-vessel fission product release, without fission product scrubbing, release begins at approximately 2.5 hrs	1.91E-08

TABLE E.2-17
SUMMARY OF REPRESENTATIVE MAAP SEQUENCES FOR TMI-1 SOURCE TERMS

MAAP CASE	NAME	DESCRIPTION	EFW	SEAL LOCA?	SPRAYS ON?	FANS ON?	TCU HOURS	TCD HOURS	HLCR HOURS	TVF HOURS	TCF HOURS	TEND HOURS	NG FRACTION	CSI FRACTION
TM0034	INTACT	No cont failure, no exvessel rel, FP scrbbed	Y	Y	Y	Y	18.8	26.0	26.7	34.6	NA	48	1.2E-01	4.6E-04
TM0035	BMMT	Basemat melt w/o debris cooling	Y	Y	N	N	18.7	26.0	26.6	34.7	64.4	48	9.7E-01	8.7E-03
TM0036	LATE - SM	Small late containment failure	6 hrs	Y	N	N	8.2	9.0	9.9	16.5	52.1	72	7.0E-01	6.5E-03
TM0037	LATE-LRG	Large containment failure	Y	Y	N	N	18.8	26.0	26.6	34.8	70.8	72	1.0E+00	6.9E-02
TM0038	EARLY	Early containment failure at vessel breach	6 hrs	Y	N	N	8.2	9.3	NA	11.7	11.7	48	1.0E+00	6.0E-02
TM0039	ISO-SM	Containment isolation failure - small	N	Y	N	N	0.6	0.8	1.4	6.0	0.0	48	8.3E-01	3.4E-02
TM0040	ISO-LRG	Containment isolation failure - large	6 hrs	Y	N	N	8.5	9.4	10.0	16.0	0.0	48	1.0E+00	2.3E-01
TM0041	ISLOCA	.003 ft^2 break	N	N	N	N	15.0	15.8	16.8	24.3	NA	72	9.2E-01	1.8E-01
TM0042	SGTR	.0066 ft^2 break	N	N	N	N	12.7	13.5	16.6	18.3	NA	48	1.0E+00	6.5E-01

Notes to Table E.2-17:

EFW	Is EFW available for makeup?
Tcu	Time of core uncovery
Tcd	Time of core damage (max core > 1800F)
Tvf	Time of vessel failure
Tcf	Time of containment failure
Tend	End time of scenario run
NG	Noble Gas release
CsI	CsI release

TABLE E.2-18
TMI-1 SOURCE TERM SUMMARY

RELEASE CATEGORY	INTACT	BMMT	LATE-SM	LATE-LRG	EARLY	ISO-SM	ISO-LRG	ISLOCA	SGTR
MAAP Case ID	TM0034	TM0035	TM0036	TM0037	TM0038	TM0039	TM000040	TM0041	TM0042
Run Duration	48 hr	72 hr	72 hr	120	48 hr	48 hr	48 hr	72 hr	48 hr
Time after Scram when General Emergency is declared (3)	26 hr	26 hr	9 hr	26 hr	9.3 hr	0.8 hr	9.4 hr	15.8 hr	13.5 hr
Fission Product Group:									
1) Noble									
Total Plume 1 Release Fraction	1.25E-01	3.00E-01	7.00E-01	1.00E+00	1.00E+00	8.30E-01	1.00E+00	9.20E-01	1.00E+00
Start of Plume 1 Release (hr)	26.00	26.00	10.00	70.80	11.70	1.00	10.00	16.00	14.00
End of Plume 1 Release (hr)	48.00	64.00	72.00	70.80	11.70	48.00	20.00	20.00	16.00
Total Plume 2 Release Fraction[2]		1.00E+00							
Start of Plume 2 Release (hr)		64.00							
End of Plume 2 Release (hr)		64.00							
2) CsI									
Total Plume 1 Release Fraction	4.60E-04	8.70E-03	6.50E-03	7.00E-02	6.00E-02	3.40E-02	2.30E-01	1.80E-01	2.00E-02
Start of Plume 1 Release (hr)	26.00	26.00	10.00	70.80	11.70	1.00	10.00	16.00	14.00
End of Plume 1 Release (hr)	30.00	50.00	20.00	100.00	11.70	8.00	16.00	25.00	14.00
Total Plume 2 Release Fraction[2]									6.50E-01
Start of Plume 2 Release (hr)									34.00
End of Plume 2 Release (hr)									44.00
3) TeO2									
Total Plume 1 Release Fraction	4.60E-04	9.00E-03	9.00E-03	2.00E-02	3.80E-02	1.50E-02	2.00E-01	6.00E-02	1.00E-02
Start of Plume 1 Release (hr)	26.00	26.00	10.00	70.80	11.70	1.00	10.00	16.00	14.00
End of Plume 1 Release (hr)	30.00	50.00	20.00	100.00	11.70	8.00	16.00	20.00	14.00
Total Plume 2 Release Fraction[2]									4.00E-02
Start of Plume 2 Release (hr)									34.00
End of Plume 2 Release (hr)									44.00

TABLE E.2-18
TMI-1 SOURCE TERM SUMMARY

RELEASE CATEGORY	INTACT	BMMT	LATE-SM	LATE-LRG	EARLY	ISO-SM	ISO-LRG	ISLOCA	SGTR
4) SrO									
Total Plume 1 Release Fraction	7.00E-05	8.50E-04	4.00E-04	5.00E-06	4.50E-03	1.50E-03	1.00E-02	6.00E-03	9.00E-04
Start of Plume 1 Release (hr)	29.00	30.00	10.00	70.80	11.70	1.00	12.00	16.00	14.00
End of Plume 1 Release (hr)	32.00	40.00	20.00	70.80	20.00	8.00	20.00	20.00	24.00
Total Plume 2 Release Fraction[2]									
Start of Plume 2 Release (hr)									
End of Plume 2 Release (hr)									
5) MoO2									
Total Plume 1 Release Fraction	3.50E-04	4.00E-03	2.80E-03	2.00E-05	2.00E-02	2.00E-02	3.50E-02	3.00E-02	6.00E-03
Start of Plume 1 Release (hr)	29.00	30.00	10.00	70.80	11.70	1.00	10.00	16.00	14.00
End of Plume 1 Release (hr)	32.00	40.00	20.00	70.80	11.70	8.00	16.00	20.00	14.00
Total Plume 2 Release Fraction[2]									
Start of Plume 2 Release (hr)									
End of Plume 2 Release (hr)									
6) CsOH									
Total Plume 1 Release Fraction	4.50E-04	9.00E-03	5.50E-03	2.00E-02	3.00E-02	1.00E-02	1.50E-01	5.00E-02	2.00E-02
Start of Plume 1 Release (hr)	26.00	26.00	10.00	70.80	11.70	1.00	10.00	16.00	14.00
End of Plume 1 Release (hr)	30.00	50.00	20.00	100.00	11.70	8.00	16.00	20.00	14.00
Total Plume 2 Release Fraction[2]									9.00E-02
Start of Plume 2 Release (hr)									34.00
End of Plume 2 Release (hr)									44.00
7) BaO									
Total Plume 1 Release Fraction	1.80E-04	3.00E-03	1.00E-03	1.20E-05	5.00E-03	9.00E-03	1.50E-02	2.50E-02	2.00E-03
Start of Plume 1 Release (hr)	29.00	30.00	10.00	70.80	11.70	1.00	10.00	16.00	14.00
End of Plume 1 Release (hr)	32.00	40.00	20.00	70.80	20.00	8.00	16.00	20.00	14.00
Total Plume 2 Release Fraction[2]									
Start of Plume 2 Release (hr)									
End of Plume 2 Release (hr)									

TABLE E.2-18
TMI-1 SOURCE TERM SUMMARY

RELEASE CATEGORY	INTACT	BMMT	LATE-SM	LATE-LRG	EARLY	ISO-SM	ISO-LRG	ISLOCA	SGTR
8) La2O3									
Total Plume 1 Release Fraction	2.00E-06	5.50E-05	3.00E-05	5.50E-07	5.50E-04	1.00E-04	9.00E-04	2.50E-04	1.00E-04
Start of Plume 1 Release (hr)	29.00	30.00	10.00	70.80	11.70	1.00	14.00	16.00	14.00
End of Plume 1 Release (hr)	32.00	40.00	20.00	70.80	20.00	8.00	20.00	20.00	24.00
Total Plume 2 Release Fraction[2]									
Start of Plume 2 Release (hr)									
End of Plume 2 Release (hr)									
9) CeO2									
Total Plume 1 Release Fraction	1.00E-05	5.20E-04	5.00E-04	1.00E-05	1.50E-02	1.50E-03	2.00E-02	1.50E-03	2.00E-03
Start of Plume 1 Release (hr)	29.00	30.00	10.00	70.80	11.70	4.00	14.00	16.00	14.00
End of Plume 1 Release (hr)	32.00	50.00	20.00	70.80	20.00	10.00	20.00	26.00	24.00
Total Plume 2 Release Fraction[2]									
Start of Plume 2 Release (hr)									
End of Plume 2 Release (hr)									
10) Sb									
Total Plume 1 Release Fraction	4.00E-04	1.50E-02	8.00E-03	5.00E-02	1.80E-01	5.00E-02	1.50E-01	1.50E-01	7.00E-01
Start of Plume 1 Release (hr)	29.00	30.00	10.00	70.80	11.70	1.00	10.00	16.00	28.00
End of Plume 1 Release (hr)	32.00	40.00	20.00	120.00	20.00	8.00	20.00	20.00	30.00
Total Plume 2 Release Fraction[2]									
Start of Plume 2 Release (hr)									
End of Plume 2 Release (hr)									
11) Te2									
Total Plume 1 Release Fraction	0.00E+00	1.00E-04	3.00E-05	1.50E-03	2.00E-04	4.00E-03	7.00E-04	9.00E-05	2.00E-04
Start of Plume 1 Release (hr)		30.00	18.00	70.80	11.70	6.00	16.00	30.00	20.00
End of Plume 1 Release (hr)		40.00	20.00	70.80	20.00	16.00	20.00	40.00	24.00
Total Plume 2 Release Fraction[2]									
Start of Plume 2 Release (hr)									
End of Plume 2 Release (hr)									

TABLE E.2-18
TMI-1 SOURCE TERM SUMMARY

RELEASE CATEGORY	INTACT	BMMT	LATE-SM	LATE-LRG	EARLY	ISO-SM	ISO-LRG	ISLOCA	SGTR
12) UO2									
Total Plume 1 Release Fraction	0.00E+00	5.00E-06	2.80E-06	1.50E-06	1.20E-04	1.00E-05	2.00E-04	5.00E-06	1.00E-05
Start of Plume 1 Release (hr)		30.00	18.00	70.80	11.70	6.00	16.00	30.00	20.00
End of Plume 1 Release (hr)		50.00	20.00	70.80	20.00	16.00	20.00	40.00	24.00
Total Plume 2 Release Fraction[2]									
Start of Plume 2 Release (hr)									
End of Plume 2 Release (hr)									

Notes to Table E.2-18:

(1) Puff releases are denoted in the table by those entries with equivalent start and end times.
(2) Plume 2 release fraction is cumulative and includes the initial plume 1 release fraction
(3) General Emergency declaration based on time of core damage per Radiological Emergency Plant for TMI, EP-AA-1009 Revision 7

TABLE E.2-19
TMI-1 INITIATING EVENT CONTRIBUTIONS TO CDF

INITIATOR	PROBABILITY	%CDF
Loss of Offsite Power	7.73E-06	32.6%
Transients	5.80E-06	24.5%
Small & Very Small LOCA	4.66E-06	19.7%
Loss of Nuclear River Water	3.67E-06	15.5%
Steam Generator Tube Rupture	9.93E-07	4.2%
Internal Floods	4.50E-07	1.9%
Large & Medium LOCA	2.06E-07	0.9%
ISLOCA	1.80E-07	0.8%

TABLE E.2-20
TMI-1 TOP INITIATING EVENT CONTRIBUTIONS FOR EACH RELEASE CATEGORY

RELEASE CATEGORY GROUP	RELEASE CATEGORY FREQUENCY (1/YR)	PERCENT CONTRIBUTION OF TOP INITIATING EVENTS
1	2.04E-6	27.5%: Loss of Instrument Air 25.2%: “A” Division SGTR 25.2%: “B” Division SGTR
2	1.93E-7	97.8%: Interfacing System LOCA 1.0%: Loss of Offsite Power 0.3%: Loss of 4160V AC Bus
3	6.60E-10	80.9%: Loss of Offsite Power 19.1%: Loss of 4160V AC Bus
4	3.78E-7	87.7%: Loss of Offsite Power 4.1%: Loss of 4160V AC Bus 3.0%: Steam Line Break
5	9.05E-7	35.3%: Loss of Offsite Power 18.1%: Loss of Nuclear River Water 13.3%: Very Small LOCA
6	1.17E-7	89.7%: Loss of Offsite Power 4.3%: Loss of 4160V AC Bus 2.2%: Very Small LOCA
7	1.26E-6	90.1% Loss of Offsite Power 3.8%: Loss of 4160V AC Bus 2.0%: Very Small LOCA
8	3.19E-6	77.5%: Loss of Offsite Power 6.4%: Very Small LOCA 4.8%: Loss of Nuclear River Water
9	1.44E-5	36.5%: Loss of Offsite Power 18.9%: Loss of Nuclear River Water 10.2%: Very Small LOCA

TABLE E.2-21
EXTERNAL FLOODING CDF SUMMARY

SEQUENCE IDENTIFIER	LEVEL 1 SEQUENCE DESCRIPTION	FREQUENCY (/YR)*
>310 Feet	No detailed core damage progression information is available for these floods in the IPEEE. Based on the available text, successful installation of flood gates would delay the time to equipment damage, but not prevent it (SBO and core damage would still occur). The IPEEE indicates that there should be several hours available between a high water level warning and the onset of flooding, even for hurricane events. This is in addition to the warnings that would exist related to any incoming storm. As a result, it is assumed that the reactor is placed in cold shutdown prior to the onset of site flooding. Core damage ultimately occurs after the failure of the extreme flooding measures.	6.37E-05
305 to 310 feet Sequence “A”	Flood event occurs, Offsite power is available, Flood preparations fail given that transition to cold shutdown was successful.	6.30E-06
305 to 310 feet Sequence “B”	Flood event occurs, Offsite power is available, Transition to cold shutdown fails, Flood preparations fail given that transition to cold shutdown failed.	6.65E-08
305 to 310 feet Sequence “C”	Flood event occurs, Offsite power is unavailable (on-site power OK), Flood preparations fail given that transition to cold shutdown was successful.	9.05E-07
305 to 310 feet Sequence “D”	Flood event occurs, Offsite power is unavailable (on-site power OK), Transition to cold shutdown fails, Flood preparations fail given that transition to cold shutdown failed.	6.10E-06
305 to 310 feet Sequence “E”	Flood event occurs, Offsite power is unavailable, On-site power is unavailable.	3.66E-06
305 to 310 feet Sequence “F”	Flood event occurs, Early warning system fails.	8.65E-08
<305 feet	A site flood with river levels between 300 and 305 feet occurs only with a dike failure. All safety equipment appears to be contained in buildings that do not have penetrations below the 305 foot level. Offsite power equipment in the switchyard is not damaged until flood levels reach 307 feet, which would imply off-site power is available if the grid is energized (not likely in a hurricane induced event). The CDF estimated in the IPEEE is based on the flooding frequency, the probability of dam failure, and an assumed 0.1 conditional core damage probability. No details are available related to the core damage progression.	2.5E-07
TOTAL		8.11E-05

* Includes credit for current severe flooding guidelines.

TABLE E.2-22
CET NODE BINNING CHARACTERISTICS

CET NODE	BINNING CHARACTERISTIC
Early Containment Failure is Prevented	Used to identify "early" containment failures. Failure of the node denotes an early containment breach has occurred while success indicates that the containment remains intact or fails late.
Late Containment Failure is Prevented	Failure of the node implies a "late" containment overpressurization failure has occurred. The success path contains both "no containment failure" cases and basemat melt through cases.
Containment Failure is Benign	For late overpressurization failure cases, success of this node indicates that containment failure results in a "small" release pathway while failure of the node indicates a "large" release pathway has opened.
Ex-Vessel Release of Fission Products is Prevented	Release of the fission products from the vessel is used to determine whether or not a basemat failure could occur. If the corium is retained in the vessel (success of the node), no basemat failure is possible. Failure of the node requires a subsequent evaluation of the interaction between the corium and the containment floor.
Containment Failure From Basemat Melt through is Prevented	For those cases in which the fission products are not retained in the vessel, failure of this node implies that the containment basemat fails due to the interaction between the concrete and the corium. Success of the node implies that the containment remains intact.

TABLE E.2-23
FLOOD SEQUENCE SOURCE TERM FREQUENCIES

FLOOD SEQUENCE	SGTR (RC1)	ISLOCA (RC2)	ISO-LRG (RC3)	ISO-SM (RC4)	EARLY (RC5)	LATE-LRG (RC6)	LATE-SM (RC7)	BMMT (RC8)	INTACT (RC9)
>310' Flood Freq.(/yr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.92E-06	4.93E-06	4.44E-05	1.43E-06	4.05E-06
305' to 310' Sequence A Freq. (/yr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.82E-07	4.88E-07	4.39E-06	1.41E-07	4.01E-07
305' to 310' Sequence B Freq. (/yr)	0.00E+00	0.00E+00	0.00E+00	6.65E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
305' to 310' Sequence C Freq. (/yr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.27E-07	7.00E-08	6.31E-07	2.03E-8	5.76E-08
305' to 310' Sequence D Freq. (/yr)	0.00E+00	0.00E+00	0.00E+00	6.10E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
305' to 310' Sequence E Freq. (/yr)	0.00E+00	0.00E+00	0.00E+00	3.66E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
305' to 310' Sequence F Freq. (/yr)	0.00E+00	0.00E+00	0.00E+00	8.65E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Floods <305' msl	1.68E-07	0.00E+00	0.00E+00	3.32E-09	2.11E-08	0.00E+00	1.09E-08	3.38E-08	1.64E-07

TABLE E.2-24
TMI PEER REVIEW SUMMARY OVERALL ASSESSMENT

PRA ELEMENT	GRADE BASED ON SUB-ELEMENTS
Initiating Events (IE)	3 (C)
Accident Sequence Evaluation (AS)	3
Thermal Hydraulic Analysis (TH)	2 (C)
Systems Analysis (SY)	3 (C)
Data Analysis (DA)	3 (C)
Human Reliability Analysis (HR)	2
Dependency Analysis (DE)	3
Structural Response (ST)	3
Quantification (QU)	3
Containment Performance Analysis (L2)	2 (C)
Maintenance and Update Process (MU)	2 (C)

Overall Assessment: The Three Mile Island PRA can be effectively used to support applications involving risk significant determinations supported by deterministic analysis, once the technical issues and recommendations for enhancements that are noted in the element summaries and Fact and Observation Sheets are addressed. When these enhancements are addressed for thermal hydraulics analysis, containment performance analysis, and the maintenance and update process, the current PRA elements are capable of supporting risk-ranking elements.

Areas Requiring Enhancement: Significant opportunities for enhancements to support applications involving risk significance determinations were identified for all PRA elements except for Accident Sequence Evaluation, Dependency Analysis, Structural Response, and Level 1 Sequence Quantification. The peer review process for TMI-1 resulted in one ‘A’, 29 ‘B’, 37 ‘C’, and 14 ‘D’ level F&O findings identified during the review. All ‘A’ and ‘B’ F&Os have been closed with the exception of SY-21. See Section E.2.4.

(C): This identifier is used to denote a grade that is conditional on the resolution of specific review comments; if the comment(s) is/are not resolved, a lower grade would be appropriate.

TABLE E.3-1
ESTIMATED POPULATION DISTRIBUTION WITHIN A 50-MILE RADIUS OF THREE MILE ISLAND, YEAR 2034

Sector	0-1 mile (1.00) [(1)]	1-2 miles (1.78) [(1)]	2-3 miles (1.00) [(1)]	3-4 miles (1.14) [(1)]	4-5 miles (1.22) [(1)]	5-10 miles (1.33) [(1)]	10-mile total
N	0	228	3110	9798	455	19442	33034
NNE	0	1226	267	684	899	24566	27642
NE	0	1930	465	667	440	4138	7639
ENE	46	228	79	706	1491	3663	6212
E	26	154	51	656	2652	27227	30766
ESE	25	411	230	547	1151	6719	9084
SE	0	1005	77	714	550	5184	7530
SSE	85	389	354	748	448	4606	6630
S	0	0	311	1693	1804	12795	16603
SSW	0	0	625	251	1061	6100	8036
SW	0	2136	567	1991	645	3262	8600
WSW	0	881	199	1785	1276	3569	7710
W	0	3090	448	2491	3593	8835	18456
WNW	0	3273	64	995	1751	17079	23162
NW	0	0	35	0	4158	46674	50867
NNW	0	0	892	1551	4192	32894	39529
Total	182	14950	7774	25277	26565	226752	301500

[(1)] Ten year radial population growth factor applied to year 2000 census data to develop year 2034 estimate.

TABLE E.3-2
ESTIMATED POPULATION DISTRIBUTION WITHIN A 50-MILE RADIUS OF THREE MILE ISLAND, YEAR 2034

Sector	0-10 miles	10-20 miles (1.09) (1)	20-30 miles (1.10) (1)	30-40 miles (1.12) (1)	40-50 miles (1.11) (1)	50-mile total
N	33034	16171	11115	12504	66687	139511
NNE	27642	21750	5535	23296	62672	140895
NE	7639	42789	76809	18906	88956	235099
ENE	6212	14482	23100	67848	300119	411762
E	30766	24171	110948	76620	66474	308978
ESE	9084	64191	201929	49553	84839	409596
SE	7530	30257	16040	25237	45943	125006
SSE	6630	69506	22672	26782	145000	270590
S	16603	127880	32539	35911	154350	367283
SSW	8036	54317	71630	37706	87671	259361
SW	8600	13149	31487	45963	36183	135382
WSW	7710	12601	15712	15080	41633	92736
W	18456	32360	56527	25691	33767	166801
WNW	23162	96481	26716	10568	7576	164503
NW	50867	113320	16415	17466	23171	221239
NNW	39529	65264	19006	14046	22665	160510
Total	301500	798690	738178	503178	1267705	3609252

(1) Ten year radial population growth factor applied to year 2000 census data to develop year 2034 estimate.

TABLE E.3-3
THREE MILE ISLAND MACCS2 CORE INVENTORY

ENTRY	NUCLIDE[(2)]	THREE MILE ISLAND MACCS2[(1)]	ENTRY	NUCLIDE[(2)]	THREE MILE ISLAND MACCS2[(1)]
1	Co-58	2.475E+16	31	Te-131m	3.774E+17
2	Co-60	1.890E+16	32	Te-132	3.774E+18
3	Kr-85	3.885E+16	33	I-131	2.645E+18
4	Kr-85m	8.620E+17	34	I-132	3.811E+18
5	Kr-87	6.067E+15	35	I-133	5.549E+18
6	Kr-88	1.702E+18	36	I-134	6.141E+18
7	Rb-86	2.397E+18	37	I-135	5.142E+18
8	Sr-89	2.900E+18	38	Xe-133	5.549E+18
9	Sr-90	3.126E+17	39	Xe-135	2.038E+18
10	Sr-91	3.959E+18	40	Cs-134	6.326E+17
11	Sr-92	4.144E+18	41	Cs-136	1.754E+17
12	Y-90	3.226E+17	42	Cs-137	4.255E+17
13	Y-91	3.548E+18	43	Ba-139	5.105E+18
14	Y-92	4.144E+18	44	Ba-140	4.920E+18
15	Y-93	4.624E+18	45	La-140	4.994E+18
16	Zr-95	4.587E+18	46	La-141	4.661E+18
17	Zr-97	4.661E+18	47	La-142	4.550E+18
18	Nb-95	4.587E+18	48	Ce-141	4.514E+18
19	Mo-99	5.031E+18	49	Ce-143	4.477E+18
20	Tc-99m	4.403E+18	50	Ce-144	3.626E+18
21	Ru-103	4.033E+18	51	Pr-143	4.403E+18
22	Ru-105	2.690E+18	52	Nd-147	1.839E+18
23	Ru-106	1.521E+18	53	Np-239	4.994E+19
24	Rh-105	2.538E+18	54	Pu-238	1.428E+16
25	Sb-127	2.767E+17	55	Pu-239	1.114E+15
26	Sb-129	8.361E+17	56	Pu-240	1.199E+15
27	Te-127	3.677E+16	57	Pu-241	4.957E+17
28	Te-127m	2.741E+17	58	Am-241	7.621E+14
29	Te-129	1.232E+17	59	Cm-242	1.794E+17
30	Te-129m	8.213E+17	60	Cm-244	1.454E+16

1. Core inventory obtained from TMI specific calculation C-1101-900-E-220-178
2. MACCS2 allows up to 60 nuclides input

TABLE E.3-4
MACCS2 RELEASE CATEGORIES VS. THREE MILE ISLAND RELEASE CATEGORIES

MACCS2 Release Categories	Three Mile Island Release Categories
1-Xe/Kr	Noble Gases
2-I	CsI
3-Cs	CsOH
4-Te	TeO2 (Sb(1) & Te2(2) are included)
5-Sr	SrO
6-Ru(Mo)	MoO2 (Mo is in Ru MACCS category)
7-La	La2O3
8-Ce	CeO2 (UO2(2) are included)
9-Ba	BaO

(1) The largest release fraction of the TeO2 and Sb category is used
(2) These release fractions are typically negligible.

TABLE E.3-5
MACCS2 BASE CASE MEAN RESULTS

SOURCE TERM (DESIGNATOR)	RELEASE CATEGORY	DOSE (P-SV)	DOSE (P-REM)	OFFSITE ECONOMIC COST ($)
1 (SGTR)	RC1-01 - RC1-02	5.72E+04	5.72E+06	2.78E+10
2 (ISLOCA)	RC2-01 - RC2-04	5.05E+04	5.05E+06	1.86E+10
3 (ISO-LRG)	RC3-01 - RC3-06	8.91E+04	8.91E+06	3.76E+10
4 (ISO-SM)	RC4-01 - RC4-08	2.93E+04	2.93E+06	8.99E+09
5 (EARLY)	RC5-01 - RC5-02	6.15E+04	6.15E+06	2.02E+10
6 (LATE-LRG)	RC6-01 - RC6-08	2.81E+04	2.81E+06	9.45E+09
7 (LATE-SM)	RC7-01 - RC7-04	1.35E+04	1.35E+06	3.82E+09
8 (BMMT)	RC8-01	2.22E+04	2.22E+06	6.28E+09
9 (INTACT)	RC9-01 - RC9-04	2.67E+03	2.67E+05	2.62E+08

TABLE E.3-6
RELEASE CATEGORY SPECIFIC MACCS2 BASE CASE MEAN RESULTS

RELEASE CATEGORY	RC1-01	RC1-02	RC2-02	RC2-04	RC3-01	RC3-02	RC3-03	RC3-04	RC4-01	RC4-02	RC4-03	RC4-04	RC5-01	RC5-02	RC6-03
$Freq.(/yr)_{BASE}$	4.57E-07	1.59E-06	1.81E-07	1.27E-08	9.07E-11	9.07E-11	1.90E-10	2.88E-10	3.90E-08	1.46E-08	8.54E-09	3.16E-07	7.39E-07	1.66E-07	2.20E-08
$Dose\text{-}Risk_{BASE}$	2.61	9.09	0.91	0.06	0.00	0.00	0.00	0.00	0.11	0.04	0.03	0.93	4.54	1.02	0.06
$OECR_{BASE}$	$12,705	$44,202	$3,367	$236	$3	$3	$7	$11	$351	$131	$77	$2,841	$14,928	$3,353	$208

Release Category	RC6-04	RC6-05	RC6-07	RC6-08	RC7-01	RC7-02	RC7-03	RC7-04	RC8-01	RC9-01	RC9-02	RC9-03	RC9-04	Sum of Annual Risk
$Freq.(/yr)_{BASE}$	2.36E-10	2.08E-11	8.00E-08	1.43E-08	2.25E-07	2.75E-09	7.45E-07	2.89E-07	3.19E-06	1.32E-05	1.69E-08	2.36E-06	1.91E-08	2.37E-05
$Dose\text{-}Risk_{BASE}$	0.00	0.00	0.22	0.04	0.30	0.00	1.01	0.39	7.08	3.53	0.00	0.63	0.01	32.61
$OECR_{BASE}$	$2	$0	$756	$135	$860	$11	$2,846	$1,104	$20,033	$3,461	$4	$618	$5	$112,259

TABLE E.3-7
EXTERNAL FLOODING BASE CASE MEAN RESULTS

Flood Category	>310'	305' to 310' Sequence A	305' to 310' Sequence B	305' to 310' Sequence C	305' to 310' Sequence D	305' to 310' Sequence E	305' to 310' Sequence F	<305' (uses LOOP RC distribution)	Total External Flood Frequency
Base Frequency	6.37E-05	6.30E-06	6.65E-08	9.05E-07	6.10E-06	3.66E-06	8.65E-08	2.50E-07	8.11E-05
Base Dose-Risk	132.75	13.13	0.19	1.89	17.87	10.71	0.25	0.37	177.16
Base OECR	4.06E+05	4.01E+04	5.98E+02	5.77E+03	5.48E+04	3.29E+04	7.78E+02	1.22E+03	$542,159

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
%AC	4.48E-02	1.484	LOSS OF OFFSITE POWER	The importance of the LOOP initiator flag provides limited information about plant risk given that the LOOP category is broad and includes several different contributors. These contributors are represented by other events in this importance list that better define specific failures that can be investigated to identify means of reducing plant risk. No credible means of reducing the TMI-1 LOOP frequency have been identified. Implementation of the Maintenance Rule is considered to address equipment reliability issues such that no measurable improvement is likely available based on enhancing maintenance practices. It may be possible to improve switchyard work planning and/or practices, but a reliable means of quantifying the impact of these types of changes is not available. No SAMAs suggested.
RECOVERY-LOOP-01	4.97E-01	1.216	NONRECOVERY OF OFFSITE POWER	This OSP recovery failure event is related to conditions in which only one EDG (potentially the SBO EDG) is available, EFW is successful, but a seal LOCA occurs due to loss of seal cooling. For these cases, auto alignment and load capability for the SBO EDG would allow recovery of emergency AC power in time to prevent seal damage (SAMA 1). Alternatively, damage resistant, high temperature seals could be installed to eliminate most of the seal leakage after loss of cooling and delay core damage long enough to align the SBO EDG or recover OSP. This SAMA also includes the use of a portable 480V AC generator to power a division of battery chargers and maintain MCR control of EFW (SAMA 2).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
%VSB	2.56E-03	1.177	VERY SMALL BREAK LOCA	Multiple failure types contribute, including failures of HPI, DHRW, and DHCCW. The DHRW and DHCCW failures may be eliminated by providing connections from the NSCCW system to the DHR heat exchangers (DH-C-1A/B) to provide emergency heat removal (SAMA 3). Some of the injection failures are caused by division "A" power failures related to "in-series" HPI minimum flow valves MU-V-36 and MU-V-37. These types of failures could be eliminated by powering these two valves from the MCC 1C ESV swing bus (SAMA 4). Alternatively, MU-V-76A and B (and MU-V-77A/B) could be replaced with MOVs to allow rapid alignment of the "C" pump to seal injection (eliminates pump damage from recirc path failures) (SAMA 5). Cross-ties between trains of the DHR related systems would also reduce risk (SAMA 6).
%LNR	3.42E-03	1.177	LOSS OF NUCLEAR RIVER WATER	A large majority of the contribution from this event corresponds to the non-recoverable NSRW failures. For many of these contributors, MU-V-76A and B (and MU-V-77A/B) could be replaced with MOVs to allow rapid alignment of the "C" pump to seal injection (eliminates pump damage from recirc path failures) (SAMA 5). For those contributors where DHRW or DHCCW fail, a hard piped connection to the FSW system could be used to cool the ICCW heat exchangers to provide backup cooling in the event that the normal supply is lost (SAMA 7).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
LOCA-SIZE-101	7.80E-01	1.164	PROBABILITY THAT RCP SEAL LOCA IS OF VSLOCA CATEGORY	Almost 40% of the contributors include hardware failures that would disable NSRW so that the cross-tie from SSRW would not be available. A hard-piped connection from the FSW could be used as a backup supply to the ICCW heat exchangers. This arrangement has the advantage over use of SSRW to NSRW that the integrity of the NSRW system does not need to be confirmed before cooling to the Thermal Barriers can be re-established through alignment of FSW to the ICCW heat exchangers. Given that the ICCW pumps would be available for the relevant cases, a local, manual valve could be used for the alignment as time should be available for such an action (SAMA 7). For other contributors, MU-V-76A and B (and MU-V-77A/B) could be replaced with MOVs to allow rapid alignment of the "C" pump to seal injection (eliminates pump damage from recirc path failures) (SAMA 5).
FLAG-SBOALIGN-1E	5.00E-01	1.103	SBO ALIGNED TO BUS 1E	The contributors containing this event lead to RCP seal LOCAs. These events could be mitigated using damage resistant, high temperature seals (SAMA 2). In addition, these events all include an unrecovered failure of the "A" AC division, which leads to failure of the HPI makeup pumps for this initiator due to loss of the "C" HPI pump minimum flow path. These failures could be addressed by powering valves MU-V-36 and MU-V-37 from MCC 1C ESV (SAMA 4). Even if the SBO EDG functions as designed, the time to align it to an emergency bus is longer that the time to assumed seal damage. If auto alignment and load capability were provided, it would reduce the seal LOCA contribution (SAMA 1).
RECOVERY-LOOP-03	8.11E-02	1.101	NONRECOVERY OF OFFSITE POWER	This power recovery event is used in cases where no EDGs are available and EFW is initially successful. Installing high temperature, damage resistant seals with a portable generator to power SG level instrumentation for EFW operation would allow long term SBO mitigation (SAMA 2).
RARB-STANDBYFLAG	5.00E-01	1.098	BOTH DHRW TRAINS A AND B IN STANDBY	The event is associated with loss of DHRW flow events. Use of the NSCCW system to cool the DHR heat exchangers (DH-C-1A/B) would provide alternate heat removal capabilities (SAMA 3).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
NON-RECOV-LNR-IE	2.70E-01	1.096	NON-RECOVERABLE FRACTION OF %LNR EVENTS	For many of the non-recoverable loss of NSRW contributors, MU-V-76A and B (and MU-V-77A/B) could be replaced with MOVs to allow rapid alignment of the "C" pump to seal injection (eliminates pump damage from recirc path failures) (SAMA 5). For those contributors where DHRW or DHCCW fail, a hard piped connection to the FSW system could be used to cool the ICCW heat exchangers to provide backup cooling in the event that the normal supply is lost (SAMA 7).
GB-EDG-1B---DGFR	2.07E-02	1.095	DIESEL 1B FAILS TO RUN	Most of the contributors containing this event lead to RCP seal LOCAs. These events could be mitigated using damage resistant, high temperature seals (SAMA 2). In addition, these events typically include an unrecovered failure of the "A" AC division, which leads to failure of the HPI makeup pumps for this initiator due to loss of the "C" HPI pump minimum flow path. These failures could be addressed by powering valves MU-V-36 and MU-V-37 from MCC 1C ESV (SAMA 4). Even if the SBO EDG is available, the time to align it to an emergency bus is longer that the time to assumed seal damage. If auto alignment and load capability were provided, it would reduce the seal LOCA contribution (SAMA 1).
GA-EDG-1A---DGFR	2.07E-02	1.081	DIESEL 1A FAILS TO RUN	Most of the contributors with EDG "A" failure result in seal LOCAs due to loss of power. A majority of the total is related to REC-LOOP-101 sequences in which EFW is available and the SBO EDG is aligned after seal damage. High temperature, damage resistant seals (SAMA 2) would address most of these cases. Alternatively, providing auto alignment and load capability for the SBO EDG would preclude initial seal damage (SAMA 1). In addition, some of these events include unrecovered failure of the "A" AC division, which leads to failure of all HPI makeup pumps for this initiator due to loss of the "C" HPI pump minimum flow path. These failures could be addressed by powering valves MU-V-36 and MU-V-37 from MCC 1C ESV (SAMA 4).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
%LNS	2.74E-03	1.079	LOSS OF NUCLEAR SERVICES CLOSED COOLING WATER	A large portion of the contributors including this event are related to the operator failure to trip the RCPs on loss of cooling. This contribution could be reduced if high temperature sensors on the motor bearing cooling water lines were installed and used to provide automatic trip signals for the pumps (SAMA 8).
RECOVERY--LNR-IE	7.30E-01	1.067	RECOVERABLE FRACTION OF %LNR EVENTS	Providing a hardpiped connection from the FSW system to the ICCW heat exchangers would provide an alternate cooling source for the ICCW system on loss of NSRW; however, the dependence between the operator action to perform this cross-tie and the one to SSRW would be high or complete and the benefit would be minimal. Enhancing the MU-V-76A/B valves so that they are operable from the MCR would allow the operators to provide a seal injection path for the "C" HPI pump in a timely manner based on different cues (SAMA 5). This option may provide slightly more benefit and would also prevent the seal LOCA that dominates the cutsets that include "RECOVERY--LNR-IE".
INHINJ2_MUHHMUOA	1.00E+00	1.067	OPERATOR OPENS CROSS CONNECT VALVES MU-V-76A/B AND STARTS MU-P-1C	MU-V-76A and B (and MU-V-77A/B) are the manual HPI swing pump valves, which require local manipulation to align. Providing motor operators to the valves with controls in the MCR would allow for rapid alignment of the "B" HPI pump to either division in accident conditions. This would also allow the "C" pump to be quickly aligned for seal injection (eliminates pump damage from recirc path failures). Provisions for allowing rapid alignment of the valve and pump power sources must also be made in order to make the SAMA fully functional (SAMA 5).
JHHOT1-XTIEHEPOA	5.10E-02	1.066	OTHOT1_RCPTHP1OA AND NR-NRSRXTIEHVAOA	The contribution from the failure of this JHEP could be reduced if high temperature sensors on the motor bearing cooling water lines were installed and used to provide automatic trip signals for the pumps (SAMA 8). The automation of the RCP trip action would remove the important dependence issue and is considered to be an effective means of addressing this dependent combination for TMI-1.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
DABB1A------BYFD	4.84E-04	1.062	FAILURE OF BATTERY BANK 1A ON DEMAND	About 75% of these contributors are LOOP/seal LOCAs with initial EFW success. Installation of the damage resistant, high temperature seals would prevent loss of primary coolant while removing heat with EFW, which would allow for operation out to at least 24 hours and provide recovery opportunities (SAMA 2). Even if the SBO EDG is available, the time to align it to an emergency bus is longer than the time to assumed seal damage. If auto alignment and load capability were provided, it would reduce the seal LOCA contribution (SAMA 1).
AV-LOCADV--HCDOA	1.00E+00	1.052	OPERATOR ACTION FAILURE TO LOCALLY OPERATE ADVS ON LOSS OF AIR	A large majority of the contributors including AV-LOCADV--HCDOA result from conditions where RCP seal cooling and HPI makeup are lost due to IA valve and power failures. Multiple SAMAs could address these circumstances, including SAMAs 1, 2, 3, 4, 5, 6, and 7; however, TMI-1 has procedures to perform the local ADV operations that are not credited in the PRA model. If these procedures are credited, the RRW of the operator action is reduced below the review threshold. SAMA 9 is used as a surrogate to demonstrate this.
GB-EG-Y-1B--DGMM	1.61E-02	1.052	Emergency Diesel Generator 1B in Maintenance	Most of the contributors containing this event lead to RCP seal LOCAs. These events could be mitigated using damage resistant, high temperature seals (SAMA 2). In addition, these events typically include an unrecovered failure of the "A" AC division, which leads to failure of the HPI makeup pumps for this initiator due to loss of the "C" HPI pump minimum flow path. These failures could be addressed by powering valves MU-V-36 and MU-V-37 from MCC 1C ESV (SAMA 4). Even if the SBO EDG is available, the time to align it to an emergency bus is longer that the time to assumed seal damage. If auto alignment and load capability were provided, it would reduce the seal LOCA contribution (SAMA 1).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
GB1BDG------DGFS	1.13E-02	1.049	DIESEL GENERATOR 1B FAILS TO START	Most of the contributors containing this event lead to RCP seal LOCAs. These events could be mitigated using damage resistant, high temperature seals (SAMA 2). In addition, these events typically include an unrecovered failure of the "A" AC division, which leads to failure of the HPI makeup pumps for this initiator due to loss of the "C" HPI pump minimum flow path. These failures could be addressed by powering valves MU-V-36 and MU-V-37 from MCC 1C ESV (SAMA 4). Even if the SBO EDG is available, the time to align it to an emergency bus is longer that the time to assumed seal damage. If auto alignment and load capability were provided, it would reduce the seal LOCA contribution (SAMA 1).
%SBL	4.50E-04	1.049	SMALL BREAK LOCA	There are multiple failure types contributing to the cutsets including this initiating event and no single change other than the installation of an independent injection/heat removal system would address all of these events. As installation of such a system is known not to be cost effective, it is not suggested as a SAMA. A potential change that could reduce some of the risk would be to provide a means of using NSCCW to cool the DHR heat exchangers (DH-C-1A/B) (SAMA 3). Another potential enhancement would be to add inter-train cross-ties to the DHR related systems (DHR, DHRW, and DHCCW) (SAMA 6).
%LGA	1.23E-03	1.047	LOSS OF GA POWER	More than half of the contributions including this event are related to operator failure to align the "C" HPI pump for seal injection. If the cross-connect valves were enhance so that they could be controlled from the MCR, this action could be performed in time to prevent seal damage or at least in time to provide an excess flow path for the "C" pump during injection phase to mitigate the loss of the recirc path (SAMA 5). Alternatively, these failures could be addressed by powering valves MU-V-36 and MU-V-37 from MCC 1C ESV to provide a minimum flow path for the "C" HPI pump (SAMA 4).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
RECOVERY-LOOP-04	4.97E-01	1.047	NONRECOVERY OF OFFSITE POWER	This recovery term is used in SBO sequences with TD EFW failures. In these cases, there is neither primary nor secondary injection available. An approach similar to what is used to mitigate the extreme external flooding scenarios could be used to address these scenarios. Making it useful for SBO conditions would require permanently installing the portable generator, primary injection pump, and secondary pump so that they could be aligned from the MCR. The submersible pumps would have to be mounted so that the suctions could easily be swapped from a piped water source to the flood water source. This SAMA would also address non-SBO loss of seal cooling cases given the ability to rapidly align alternate seal cooling (SAMA 11).
HP-_14A_14BCVAFD	2.03E-04	1.045	HPI Train Fails MOV CCF Op MU-V-14A;14B	Failures of the HPI BWST suction path through valves 14A and 14B could be mitigated by proceduralizing the use of the LPI system to operate as the suction path for the HPI pumps in the injection mode (SAMA 12). Some interlock bypasses may be required.
GA-EG-Y-1A--DGMM	1.61E-02	1.043	Emergency Diesel Generator 1A in Maintenance	Most of the contributors with EDG "A" failures result in seal LOCAs due to loss of power. A majority of the total is related to REC-LOOP-101 sequences in which EFW is available and the SBO EDG is aligned after seal damage. High temperature, damage resistant seals (SAMA 2) would address most of these cases . Alternatively, providing the ability to rapidly align the SBO EDG would preclude initial seal damage (SAMA 1). In addition, some of these events include unrecovered failure of the "A" AC division, which leads to failure of all HPI makeup pumps for this initiator due to loss of the "C" HPI pump minimum flow path. These failures could be addressed by powering valves MU-V-36 and MU-V-37 from MCC 1C ESV (SAMA 4).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
GA1ADG------DGFS	1.13E-02	1.042	DIESEL GENERATOR 1A FAILS TO START	Most of the contributors with EDG "A" failures result in seal LOCAs due to loss of power. A majority of the total is related to REC-LOOP-101 sequences in which EFW is available and the SBO EDG is aligned after seal damage. High temperature, damage resistant seals (SAMA 2) would address most of these cases . Alternatively, providing the ability to rapidly align the SBO EDG would preclude initial seal damage (SAMA 1). In addition, some of these events include unrecovered failure of the "A" AC division, which leads to failure of all HPI makeup pumps for this initiator due to loss of the "C" HPI pump minimum flow path. These failures could be addressed by powering valves MU-V-36 and MU-V-37 from MCC 1C ESV (SAMA 4).
%SLT	4.22E-03	1.038	STEAM LINE BREAK IN TURBINE BUILDING	A large the contributor to TB steam line break scenarios is the failure of the operators to start the IA compressors on emergency power after a low voltage trip in conjunction with an ESAS. If the IA system logic were altered to automatically load the IA-P-1A/B compressors when power is restored after an ESAS, this would reduce the probability that IA would not be available (SAMA 13).
GA-1A1BSBO-CDGFR	1.53E-04	1.037	EDG CCF Run DG-1A;DG-1B;DG-SBO	The primary contribution from this event comes from SBO with initial success of the TD EFW pump. Installing the high temperature, damage resistant seals will prevent a significant seal LOCA and using a portable 480V AC generator to power a battery charger would allow long term operation of the TD EFW pump (SAMA 2).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
EFEFP1------P7FR	5.06E-02	1.036	TURBINE-DRIVEN PUMP EF-P-1 FAILS TO RUN	Most of the contribution related to this event comes from SBO sequences. In these cases, there is neither primary nor secondary injection available. An approach similar to what is used to mitigate the extreme external flooding scenarios could be used to address these scenarios. Making it useful for SBO conditions would require permanently installing the portable generator, primary injection pump, and secondary pump so that they could be aligned from the MCR. The submersible pumps would have to be mounted so that the suctions could easily be swapped from a piped water source to the flood water source. This SAMA would also address non-SBO loss of seal cooling cases given the ability to rapidly align alternate seal cooling (SAMA 11).
HP-MU-P-1B--P2MM	7.46E-03	1.036	Makeup Pump (Operating) 1B in Maintenance	Many of the contributors related to this event could be eliminated if the HPI pump cooling supply valves were replaced with MOVs controllable from the MCR. This would allow rapid alignment of an alternate cooling source to available pumps in the event that the normal supply is lost (SAMA 14).
JHHHL1AHSR2HEPOA	2.00E-04	1.035	DLHHL1A----HVHOA AND SAHSR2-----HSROA	This joint human error probability includes operator failure to perform swap to recirculation mode and failure to open the drop line. A potential change that could reduce some of the risk would be to automate the swap to recirculation mode when the BWST has been depleted (SAMA 15).
FLAG-SBOALIGN-1D	5.00E-01	1.034	SBO ALIGNED TO BUS 1D	The contributors containing this event lead to RCP seal LOCAs. If auto alignment and load capability were provided, it would reduce the seal LOCA contribution (SAMA 1). Alternatively, these events could be mitigated using damage resistant, high temperature seals (SAMA 2).
HA-P-1AP-1BCP2FS	1.50E-04	1.034	DH Clsd Cool Stdby Pmp CCF Strt P2-1A;1B	A majority of the CCF DHCCW pump failures are important because they fail the heat sink for DHR. Failures of the DHCCW pumps may be mitigated by providing a connection from the NSCCW system to the DHR (DH-C-1A/B) heat exchangers to provide emergency heat removal (SAMA 3)

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
%LAIR	5.23E-03	1.033	LOSS OF AIR INITIATING EVENT	A primary contributor related to this initiating event is related to the failure of operators to operate the EFW flow control valves after loss of air and a dependent operator failure to initiate HPI. Providing logic to auto-start HPI on low pressurizer level would reduce the risk of this scenario (SAMA 16). In addition, a connection to the plant Service Air system exists that is not currently credited in the model. Use of this system to recover IA is possible if the integrity of the IA system is not compromised by the IE. Crediting this cross-tie would also reduce the importance of this IE. Finally, a significant contributor is event "AV-LOCADV--HCDOA", which is addressed above.
JHHOTHMRXTIHEPOA	3.10E-03	1.033	OTHOT1_RCPTHP1OA; MRHMR1-----HMUOA; NR-NRSRXTIEHVAOA	This JHEP is important for cases where %LNR has failed thermal barrier cooling, contributed to loss of seal injection, created a small LOCA via loss of RCP bearing cooling, and failed the remaining HPI source. These types of scenarios would be reduced in frequency by automating RCP trip on high motor bearing coolant temperature (SAMA 8).
HADC-V-2A---VCFT	3.00E-03	1.031	DC-V2A FAILS TO REMAIN OPEN	Providing cross-ties between the DHR cooling water systems (DHRW, DHCCW, and DHR) would provide a means of restoring cooling to the HPI pumps and the DHR heat exchangers in many cases (SAMA 6). In addition, some contributors could be addressed by providing an alternate means of flow to the DHR heat exchangers (DH-C-1A/B) (SAMA 3). It should be noted that while the ability to rapidly transfer the SBO EDG to the alternate division of power exists, no credit is taken for this capability in the model. As a result, equipment failures after SBO EDG alignment are not recovered while there is a chance that the SBO EDG could be aligned to the opposite division to support use of potentially available equipment.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
HADC-V-65A--VCFT	3.00E-03	1.031	DC-V65A TRANSFERS TO DIFFERENT STATE	Providing cross-ties between the DHR cooling water systems (DHRW, DHCCW, and DHR) would provide a means of restoring cooling to the HPI pumps and the DHR heat exchangers in many cases (SAMA 6). In addition, some contributors could be addressed by providing an alternate means of flow to the DHR heat exchangers (DH-C-1A/B) (SAMA 3). It should be noted that while the ability to rapidly transfer the SBO EDG to the alternate division of power exists, no credit is taken for this capability in the model. As a result, equipment failures after SBO EDG alignment are not recovered while there is a chance that the SBO EDG could be aligned to the opposite division to support use of potentially available equipment.
RB-RUNNING--FLAG	2.50E-01	1.026	DHRW TRAIN B RUNNING AND TRAIN A IN STANDBY	Providing cross-ties between the DHR cooling water systems (DHRW, DHCCW, and DHR) would provide a means of restoring cooling to the HPI pumps and the DHR heat exchangers in many cases (SAMA 6). In addition, some contributors could be addressed by providing an alternate means of flow to the DHR heat exchangers (DH-C-1A/B) (SAMA 3).
HA-DC-P-1A--P1MM	2.84E-03	1.026	Decay Heat Closed Cycle Cooling Water Pump 1A in Maintenance	Providing cross-ties between the DHR cooling water systems (DHRW, DHCCW, and DHR) would provide a means of restoring cooling to the HPI pumps and the DHR heat exchangers in many cases (SAMA 6). In addition, some contributors could be addressed by providing an alternate means of flow to the DHR heat exchangers (DH-C-1A/B) (SAMA 3). It should be noted that while the ability to rapidly transfer the SBO EDG to the alternate division of power exists, no credit is taken for this capability in the model. As a result, equipment failures after SBO EDG alignment are not recovered while there is a chance that the SBO EDG could be aligned to the opposite division to support use of potentially available equipment.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
LOCA-SIZE-100	2.20E-01	1.026	PROBABILITY THAT RCP SEAL LOCA IS OF SLOCA CATEGORY	About 50% of the contributors including LOCA-SIZE-100 result from the failure of NSRW to cool ICCW and to supply cooling to the running makeup pump in conjunction with failures that eliminate the remaining trains of seal injection. A hard-piped connection from the FSW could be used as a backup supply to the ICCW heat exchangers and maintain seal cooling. Given that the ICCW pumps would be available for the relevant cases, a local, manual valve could be used for the alignment as time should be available for such an action (SAMA 7).
OP-OPB-CONDITION	3.00E-01	1.026	POWER SUPPLY UNAVAILABLE GIVEN A TURBINE BYPASS SIGNAL	This event represents the probability that non-emergency electrical power will be lost due to damage from a steam line break in the turbine building. A large the contributor to these scenarios is the failure of the operators to start the IA compressors on emergency power after a low voltage trip in conjunction with an ESAS. If the IA system logic were altered to automatically load the IA-P-1A/B compressors when power is restored after an ESAS, this would reduce the probability that IA would not be available (SAMA 13).
NRHNS8A----HP1OA	5.37E-01	1.025	OPERATOR FAILS TO ISOLATE FAILED RW PUMP (POWER UNAVAILABLE)	A large majority of the contributors including event NRHNS8A----HP1OA include the operator failure to open valves MU-V-76A/B to allow seal injection with the "C" HPI pump. MU-V-76A and B (and MU-V-77A/B) are the manual HPI swing pump valves, which require local manipulation to align. Providing motor operators to the valves with controls in the MCR would allow for rapid alignment of the "B" HPI pump to either division in accident conditions. This would also allow the "C" pump to be quickly aligned for seal injection (eliminates pump damage from recirc path failures). Provisions for allowing rapid alignment of the valve and pump power sources must also be made in order to make the SAMA fully functional (SAMA 5).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
HADC-P-1A---P2FS	2.46E-03	1.025	DHCCW PUMP DC-P1A FAILS TO START	Providing cross-ties between the DHR cooling water systems (DHRW, DHCCW, and DHR) would provide a means of restoring cooling to the HPI pumps and the DHR heat exchangers in many cases (SAMA 6). In addition, some contributors could be addressed by providing an alternate means of flow to the DHR heat exchangers (DH-C-1A/B) (SAMA 3). It should be noted that while the ability to rapidly transfer the SBO EDG to the alternate division of power exists, no credit is taken for this capability in the model. As a result, equipment failures after SBO EDG alignment are not recovered while there is a chance that the SBO EDG could be aligned to the opposite division to support use of potentially available equipment.
JHHEF1-HBW1HEPOA	1.00E-04	1.024	EFHEF1_OPERH2HOA AND BWHBW1-----HP2OA	Providing logic to auto-start HPI on low pressurizer level would reduce the risk of the scenarios including operator failures to initiate HPI (SAMA 16). It should be noted, however, that a connection to the plant Service Air system exists that is not currently credited in the model. Use of this system to recover IA is possible if the integrity of the IA system is not compromised by the IE.
INMU-P-1C--HMUOA	1.00E+00	1.024	OPERATOR FAILURE TO ALIGN AND START MU-P-1C	Alignment of the "C" HPI pump for seal injection cannot be accomplished in time to prevent RCP seal damage due to the local, manual valve actions required to get the cooling flow aligned. Providing the ability to perform the alignment rapidly from the MCR would allow this action to be taken in the required time frame (SAMA 5).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
NRNR-V-20A--VPFD	1.35E-03	1.024	CHECK VALVE NR-V20A FAILS TO RESEAT	These events are tied to loss of NSRW due to back flow of a tripped pump. The main contributors include loss of div "A" power so that only HPI pump "C" is available for seal injection/makeup. Because MU-V-76A/B require local operation to align the "C" pump for seal injection, time is not available to perform the alignment before a seal LOCA occurs and the loss of "A" power fails the min flow recirc path, so all HPI will be lost. Providing motor operators to the valves with controls in the MCR would allow the "C" pump to be quickly aligned for seal injection (eliminates pump damage from recirc path failures). Provisions for allowing rapid alignment of the valve and pump power sources must also be made in order to make the SAMA fully functional (SAMA 5). Alternatively, FSW could be used as an alternate cooling medium for the ICCW heat sinks to maintain thermal barrier cooling (SAMA 7).
TH-HPIOFF--HP2OA	1.00E+00	1.024	OPERATOR FAILS TO SECURE ALL MU/HPI PUMPS TO PREVENT OVERCOOLING	This action is primarily associated with steam line breaks. Inclusion of logic to auto isolate the steam generators on high steam line flow would reduce the isolation failure (SAMA 17).
NR-NRSRXTIEHVAOA	1.00E-01	1.024	OPERATOR FAILS TO PERFORM CROSS-TIE IN TIME TO PREVENT LOSS OF RCP SEAL COOLING	Many contributors including event "NR-NRSRXTIEHVAOA" also include failure to locally operate MU-V-76A and B (and MU-V-77A/B) to align the "C" HPI pump for seal injection. Providing motor operators to the valves with controls in the MCR would allow the "C" pump to be quickly aligned for seal injection (eliminates pump damage from recirc path failures). Provisions for allowing rapid alignment of the valve and pump power sources must also be made in order to make the SAMA fully functional (SAMA 5). In addition, other contributors include failure of both NSRW and DHCCW. In these cases, FSW could be used as an alternate cooling medium for the ICCW heat sinks to maintain thermal barrier cooling (SAMA 7).
JHAHCD4RE27HEPOA	9.17E-05	1.023	AVHCD4_FF--HCDOA AND BWST-HRE27-HTKOA	Automating BWST refill would effectively eliminate this JHEP and provide a reliable means of maintaining level in the BWST (SAMA 10).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
JHHNS6-HOT1HEPOA	3.00E-02	1.023	NSHNS6-----HHXOA AND OTHOT1_RCPTHP1OA	Automating Reactor Coolant Pump Trip on high motor bearing coolant temperature would eliminate this JHEP and reduce the probability of seal failures (SAMA 8).
HBDC-V-2B---VCFT	3.00E-03	1.023	DC-V2B FAILS TO REMAIN OPEN	Providing cross-ties between the DHR cooling water systems (DHRW, DHCCW, and DHR) would provide a means of restoring cooling to the HPI pumps and the DHR heat exchangers in many cases (SAMA 6). In addition, some contributors could be addressed by providing an alternate means of flow to the DHR heat exchangers (DH-C-1A/B) (SAMA 3). In addition, some scenarios could be mitigated by enhancing the SBO DG so that it could be rapidly aligned to either division. This would benefit the cases where the SBO EDG is aligned to a particular division only to flow up with an equipment failure specific to that division (SAMA 1).
HBDC-V-65B--VCFT	3.00E-03	1.023	DC-V65B TRANSFERS TO DIFFERENT STATE	Providing cross-ties between the DHR cooling water systems (DHRW, DHCCW, and DHR) would provide a means of restoring cooling to the HPI pumps and the DHR heat exchangers in many cases (SAMA 6). In addition, some contributors could be addressed by providing an alternate means of flow to the DHR heat exchangers (DH-C-1A/B) (SAMA 3). It should be noted that while the ability to rapidly transfer the SBO EDG to the alternate division of power exists, no credit is taken for this capability in the model. As a result, equipment failures after SBO EDG alignment are not recovered while there is a chance that the SBO EDG could be aligned to the opposite division to support use of potentially available equipment.
OP230KV-----OGFD	2.40E-03	1.022	LOSS OF 230KV TO AUX XFRMR 1A AND 1B	Many contributors to consequential LOOP events could be addressed by installing high temperature, damage proof seals in conjunction with a 480V AC generator to support continued EFW operation from the MCR (SAMA 2). Other contributors would benefit from changing the IA system logic so that it automatically reloads after power is restored (SAMA 13).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
RA-RUNNING--FLAG	2.50E-01	1.022	DHRW TRAIN A RUNNING	Providing cross-ties between the DHR cooling water systems (DHRW, DHCCW, and DHR) would provide a means of restoring cooling to the HPI pumps and the DHR heat exchangers in many cases (SAMA 6). In addition, some contributors could be addressed by providing an alternate means of flow to the DHR heat exchangers (DH-C-1A/B) (SAMA 3).
%TRIB	2.86E-03	1.021	INITIATING EVENT FOR SGTR ON OTSG B	Over 80% of the contribution from the cutsets including this initiating event include operator failures to refill the BWST. Automating refill of the BWST is a potential means of improving the reliability of the refill function (SAMA 10).
%TRIA	2.86E-03	1.021	INITIATING EVENT FOR SGTR ON OTSG A	Over 80% of the contribution from the cutsets including this initiating event include operator failures to refill the BWST. Automating refill of the BWST is a potential means of improving the reliability of the refill function (SAMA 10).
HB-DC-P-1B--P1MM	2.84E-03	1.021	Decay Heat Closed Cycle Cooling Water Pump 1B in Maintenance	Providing cross-ties between the DHR cooling water systems (DHRW, DHCCW, and DHR) would provide a means of restoring cooling to the HPI pumps and the DHR heat exchangers in many cases (SAMA 6). In addition, some contributors could be addressed by providing an alternate means of flow to the DHR heat exchangers (DH-C-1A/B) (SAMA 3). It should be noted that while the ability to rapidly transfer the SBO EDG to the alternate division of power exists, no credit is taken for this capability in the model. As a result, equipment failures after SBO EDG alignment are not recovered while there is a chance that the SBO EDG could be aligned to the opposite division to support use of potentially available equipment.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
RADR-V-1A---VAFD	3.28E-03	1.021	DR-V-1A FAILS TO OPEN ON DEMAND	Failure of DR-V-1A contributes to both long term recirculation failures and LOOP related seal LOCAs. Installing a cross-connect from NSCCW to the DHR heat exchangers would provide an alternate means of removing decay heat for many of the loss of DHR cases (SAMA 3). Alternatively, adding cross-ties between the DHR systems would allow the operators to establish DHR in cases where opposite trains of the DHR systems are failed for different reasons (SAMA 6). The LOOP induced seal LOCAs typically occur because the SBO EDG cannot be aligned in time to provide power for seal cooling. Enhancing the SBO EDG with auto alignment and load capability would reduce these contributions (SAMA 1).
EF-CCFEFW-LETHAL	4.25E-04	1.02	LETHAL SHOCK TO THE EFW SYSTEM DUE TO COMMON CAUSE FAILURES	There are multiple contributors to cutsets including lethal EFW CCF, but about 40% are related to operator failure to manually initiate HPI. Automating HPI initiation on low level would reduce the reliance on operator action to perform this function (SAMA 16).
GSHEO1A----HDGOA	2.66E-02	1.019	OPERATOR FAILS TO STARTSBODG	Over 90% of the cutsets including this event are SBO sequences and 65% are SBOs in which EFW is initially available. Auto start and load capability for the SBO EDG would essentially eliminate the contribution of these failures (SAMA 1). The scenarios with EFW available could be addressed by installing high temperature, damage resistant seals that would prevent seal LOCAs (SAMA 2).
HBDC-P-1B---P2FS	2.46E-03	1.018	DHCCW PUMP DC-P1A FAILS TO START	Providing cross-ties between the DHR cooling water systems (DHRW, DHCCW, and DHR) would provide a means of restoring cooling to the HPI pumps and the DHR heat exchangers in many cases (SAMA 6). In addition, some contributors could be addressed by providing an alternate means of flow to the DHR heat exchangers (DH-C-1A/B) (SAMA 3). It should be noted that while the ability to rapidly transfer the SBO EDG to the alternate division of power exists, no credit is taken for this capability in the model. As a result, equipment failures after SBO EDG alignment are not recovered while there is a chance that the SBO EDG could be aligned to the opposite division to support use of potentially available equipment.

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
%LGB	1.23E-03	1.018	LOSS OF GB POWER	Many of the %LGB events are coupled with what are assumed to be non-recoverable electrical failures of the "A" division that fail "A" HPI. The result is a seal LOCA with no makeup capability. A potential mitigation method would be to permanently mount the extreme flooding equipment so that seal injection and secondary side cooling are available in SBO equivalent conditions (SAMA 11).
MRHMR1-----HMUOA	1.03E-02	1.018	OPERATOR FAILS TO RECOGNIZE AND ESTABLISH MIN FLOW RECIRC PATH	A large majority of the contributors containing this event are combined with the "INHINJ2_MUHHMUOA" operator action to cross-connect the "C" HPI pump for seal injection. Either "MRHMR1-----HMUOA" or "INHINJ2_MUHHMUOA" would provide a minimum flow path for the "C" pump, but the alignment of the pump for seal injection is a more visible and familiar cue that would prevent damage to the pump. Replacing the MU-V-76A/B valves (and 77A/B for easy swap of the "B" pump) would allow the operator to perform the alignment of the "C" pump in a timely manner and reduce the contribution from these scenarios (SAMA 5).
JHHAMHEFHBWHEPOA	2.40E-04	1.017	JHHAM2-HEF1HEPOA AND BWHBW1-----HP2OA	Nearly 80% of the contribution including this cutset is related to a steamline break that causes a trip of the off-site power source and subsequently requires the re-loading of IA onto emergency power. If the IA logic were modified to automatically re-load IA once emergency power is established, the requirement for the operator action would be removed (SAMA 13).
HADC-P-1A---P2FR	1.63E-03	1.016	DHCCW PUMP DC-P1A FAILS DURING OPERATION	Failure of HADC-P-1A---P2FR contributes to both long term recirculation failures and LOOP related seal LOCAs. Installing cross-connects from NSCCW to the DHR heat exchangers would provide an alternate means of removing decay heat for many of the loss of DHR cases (SAMA 3). Alternatively, adding cross-ties between the DHR systems would allow the operators to establish DHR in cases where opposite trains of the DHR systems are failed for different reasons (SAMA 6). The LOOP induced seal LOCAs typically occur because the SBO EDG cannot be aligned in time to provide power for seal cooling. Enhancing the SBO EDG with auto start and load capability would reduce these contributions (SAMA 1).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
GA-1A-1B---CDGFR	2.31E-04	1.016	EDG CCF Run DG-1A;DG-1B	Many of the contributors including this event could be mitigated by enhancing the SBO EDG auto start and load capability so that it can restore seal cooling in time to prevent a seal LOCA (SAMA 1). In other cases, the SBO EDG is failed and would not be available. In these cases, replacing the RCP seals with high temperature, damage resistant seals would allow the operators to maintain RCS integrity and remove heat with the EFW system. Typically, a portable 480V AC generator would be required to provide instrument and control power for EFW to improve the reliability of EFW operation (SAMA 2).
DABATTCHGR-HBCOA	1.00E-01	1.016	HEP FOR FAILURE TO ALIGN SPARE CHARGER 1E OR 1F	This action is proceduralized at the plant, but the time requirements and reliability of the action could be improved by providing controls in the MCR (SAMA 18).
RADR-V-1B---VAFD	3.28E-03	1.015	DR-V-1B FAILS TO OPEN ON DEMAND	Failure of DR-V-1B contributes to both long term recirculation failures and LOOP related seal LOCAs. Installing cross-connects from NSCCW to the DHR heat exchangers would provide an alternate means of removing decay heat for many of the loss of DHR cases (SAMA 3). Alternatively, adding cross-ties between the DHR systems would allow the operators to establish DHR in cases where opposite trains of the DHR systems are failed for different reasons (SAMA 6). The LOOP induced seal LOCAs typically occur because the SBO EDG cannot be aligned in time to provide power for seal cooling. Enhancing the SBO EDG with the capability to auto start and load would reduce these contributions (SAMA 1).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
GS-SBODG----DGFR	2.07E-02	1.015	SBO DIESEL FAILS TO RUN	More than half of the contributions including this event are related to SBO cases in which the EFW system is available. For these cases, installing damage resistant, high temperature seals could be installed to eliminate most of the seal leakage after loss of cooling and delay core damage long enough to align the SBO EDG or recover OSP. This SAMA also includes the use of a portable 480V AC generator to power a division of battery chargers and maintain MCR control of EFW (SAMA 2). An additional 25% of the cases are related to SBO events where the EFW system fails. The result is a seal LOCA with no makeup capability. A potential mitigation method would be to permanently mount the extreme flooding equipment so that seal injection and secondary side cooling are available in SBO equivalent conditions (SAMA 11).
HA-P-1AP-1BCP2FR	6.12E-05	1.013	DH Clsd Cool Stndby Pmp CCF Run P2-1A;1B	A majority of the CCF DHCCW pump failures are important because they fail the heat sink for DHR. Failures of the DHCCW pumps may be mitigated by providing connections from the NSCCW system to the DHR (DH-C-1A/B) heat exchangers to provide emergency heat removal (SAMA 3)
AMSC-V-52B--VCFD	6.38E-03	1.013	AIR OPERATED VALVE SC-V-52B FAILS TO OPEN/D	About 70% of the contributors including this event also include the event "AV-LOCADV--HCDOA", which is conservatively modeled in the TMI-1 PRA model. SAMA 9 demonstrates that when appropriate credit is taken for this action, the RRW is reduced below the SAMA review cutoff level.
AMSC-V-58---VCFD	6.38E-03	1.013	F.S. COOLING IA-P1A SC-V-58/D	About 70% of the contributors including this event also include the event "AMSC-V-58---VCFD", which is conservatively modeled in the TMI-1 PRA model. SAMA 9 demonstrates that when appropriate credit is taken for this action, the RRW is reduced below the SAMA review cutoff level.
FLAG----NRNORMAB	3.23E-01	1.013	FRACTION THAT NR PUMPS A AND B ARE NORMALLY RUNNING	A large majority of the contributors including this event also include the event "INHINJ2_MUHHMUOA", which represents the failure of the operators to align the "C" HPI pump for seal injection. Enhancing the MU-V-76A/B valves so that they are operable from the MCR would allow the operators to provide a seal injection path for the "C" HPI pump in a timely manner based on different cues (SAMA 5).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
JHHMR1-XTIEHEPOA	2.30E-03	1.013	MRHMR1-----HMUOA AND NR-NRSRXTIEHVAOA	A large majority of the contributors containing this event are combined with the "INHINJ2_MUHHMUOA" operator action to cross-connect the "C" HPI pump for seal injection. Either "MRHMR1-----HMUOA" or "INHINJ2_MUHHMUOA" would provide a minimum flow path for the "C" pump, but the alignment of the pump for seal injection is a more visible and familiar cue that would prevent damage to the pump. Replacing the MU-V-76A/B valves (and 77A/B for easy swap of the "B" pump) would allow the operator to perform the alignment of the "C" pump in a timely manner and reduce the contribution from these scenarios (SAMA 5).
RADR-P-1A---P5FR	1.51E-03	1.013	FAILURE OF DECAY HEAT RIVER WATER PUMP A (DR-P1A) TO RUN	Failure of DR-P1A contributes to both long term recirculation failures and LOOP related seal LOCAs. Installing cross-connects from NSCCW to the DHR heat exchangers would provide an alternate means of removing decay heat for many of the loss of DHR cases (SAMA 3). Alternatively, adding cross-ties between the DHR systems would allow the operators to establish DHR in cases where opposite trains of the DHR systems are failed for different reasons (SAMA 6). The LOOP induced seal LOCAs typically occur because the SBO EDG cannot be aligned in time to provide power for seal cooling. Enhancing the SBO EDG with the capability to auto start and load would reduce these contributions (SAMA 1).
RA-V-1AV-1BCVAFD	1.34E-04	1.012	DHRW MOV CCF Operate on Demand V-1A;1B	A large majority of the contributors including this event are related to failure of the DHRW system to provide long term heat removal. These contributors could be addressed by providing an alternate method of cooling the DHR heat exchangers (DH-C-1A/B) with NSCCW (SAMA 3).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
GAEDG-STARTCDGFS	5.25E-05	1.012	EDG Fail to Start CCF DG-All 3	About 69% of the contributions including this event are related to SBO cases in which the EFW system is available. For these cases, installing damage resistant, high temperature seals could be installed to eliminate most of the seal leakage after loss of cooling and delay core damage long enough to align the SBO EDG or recover OSP. This SAMA also includes the use of a portable 480V AC generator to power a division of battery chargers and maintain MCR control of EFW (SAMA 2). An additional 29% of the cases are related to SBO events where the EFW system fails. The result is a seal LOCA with no makeup capability. A potential mitigation method would be to permanently mount the extreme flooding equipment so that seal injection and secondary side cooling are available in SBO equivalent conditions (SAMA 11).
HBDC-P-1B---P2FR	1.63E-03	1.012	DHCCW PUMP DC-P1B FAILS DURING OPERATION	Providing cross-ties between the DHR cooling water systems (DHRW, DHCCW, and DHR) would provide a means of restoring cooling to the HPI pumps and the DHR heat exchangers in many cases (SAMA 6). In addition, some contributors could be addressed by providing an alternate means of flow to the DHR heat exchangers (DH-C-1A/B) (SAMA 3). It should be noted that while the ability to rapidly transfer the SBO EDG to the alternate division of power exists, no credit is taken for this capability in the model. As a result, equipment failures after SBO EDG alignment are not recovered while there is a chance that the SBO EDG could be aligned to the opposite division to support use of potentially available equipment.
HPMU-P-1A---P2FS	2.46E-03	1.012	MAKEUP PUMP A FAILS TO START	Over half of the contribution from this event is related to seal LOCAs in which NSRW cooling to ICCW is lost. Providing an alternate means of cooling the ICCW heat exchangers would prevent the seal LOCAs in these sequences. FSW could be used as a backup cooling source for the ICCW heat exchangers. Given that the ICCW pumps would be available for the relevant cases, a local, manual valve could be used for the alignment as time should be available for such an action (SAMA 7).

TABLE E.5-1
LEVEL 1 IMPORTANCE LIST REVIEW

EVENT NAME	PROB-ABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
HP-MU-P-1A--P2MM	2.21E-03	1.01	Makeup Pump (Standby) 1A in Maintenance	Over half of the contribution from this event is related to seal LOCAs in which NSRW cooling to ICCW is lost. Providing an alternate means of cooling the ICCW heat exchangers would prevent the seal LOCAs in these sequences. FSW could be used as a backup cooling source for the ICCW heat exchangers. Given that the ICCW pumps would be available for the relevant cases, a local, manual valve could be used for the alignment as time should be available for such an action (SAMA 7).
HL-V-7AV-7BCVAFD	2.03E-04	1.01	Line UP DHR HP Recrc MOV CCF Op V-7A;7B	The low position of this event in the importance list indicates that hardware changes to specifically address the CCF of the DHR to HPI suction valves (DH-V-7A/B) would not be cost beneficial. The dominant contributor for this event is when it is paired with a small break LOCA alone (38% of contribution). In this case, the only options for mitigation appear to be the installation of a bypass line or an alternate DHR method. A manually operated bypass would be effective assuming it was accessible, but a more appropriate approach for addressing this risk is believed to be through the seal LOCAs. Prevention of the seal/consequential LOCAs would preclude the need for HPR. The SAMAs suggesting the installation of high temperature, damage resistant seals (SAMA 2) and automated RCP trip logic (SAMA 8) would address the seal/consequential LOCAs contributors related to this event.
OTHOT1_RCPTHP1OA	1.44E-02	1.01	OPERATOR FAILS TO TRIP REACTOR COOLANT PUMP ON LOSS OF NSCCW	The contribution from the failure of this action could be reduced if high temperature sensors on the motor bearing cooling water lines were installed and used to provide automatic trip signals for the pumps (SAMA 8).
RA-P-1AP-1BCP5FR	5.35E-05	1.01	DHRW Standby RW Pump CCF Run P5-1A;1B	The event is associated with loss of DHRW flow scenarios. Use of the NSCCW system to cool the DHR heat exchangers (DH-C-1A/B) would provide alternate heat removal capabilities (SAMA 3).

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
%AC	4.48E-02	2.161	LOSS OF OFFSITE POWER	Addressed by a similar event the Level 1 importance list.
RECOFFSITEPWR	9.64E-01	1.698	OFFSITE POWER RECOVERED WITHIN 24 HOURS	About 80% of the contributors including RECOFFSITEPWR are SBO events, which are represented by events RECOVERY-LOOP-03 and RECOVERY-LOOP-04. These events are addressed in the Level 1 importance list and the same SAMAs are applicable for RECOFFSITEPWR. An additional insight is that 80% of the contributors including RECOFFSITEPWR belong to RC8-01. These sequences are characterized by ex-vessel releases of corium and basemat failure. Ex-vessel release occurs due to lack of containment spray early while basemat failure largely occurs in spite of late recovery of containment sprays, which implies that early recovery of AC power would allow containment spray to prevent the ex-vessel release.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
MELT	5.00E-01	1.668	Likelihood That Water Pool in Cavity Will Not Stop Concrete Attack	This event represents the probability that water will not prevent interaction between the core melt debris and the containment floor (containment has performed as designed, but the sprays cannot prevent containment damage). Over 50% of the cutset contributions including the event MELT are SBO events, which are represented by events RECOVERY-LOOP-03 and RECOVERY-LOOP-04. These events are addressed in the Level 1 importance list and the same SAMAs are applicable for MELT. An additional 20% to 25% of the contributors are cases where the SBO EDG is available, but cannot be aligned in time to prevent a seal LOCA. These cases are addressed by SAMA 1. No potentially cost effective containment structure changes have been identified to address this issue (installation of a flooded rubble bed was estimated to be over $18 million for the ABWR [GE 1994]).
RECSPRAYLT	9.99E-01	1.614	AVAILABILITY OF CONTAINMENT SPRAYS WITHOUT POWER DEPENDENCY	RECSPRAYLT is completely tied to event RECOFFSITEPWR, which is addressed separately in this table.
RECOVERY-LOOP-03	8.11E-02	1.355	NONRECOVERY OF OFFSITE POWER	Addressed by a similar event the Level 1 importance list.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
RBSPRAY	9.99E-01	1.263	RB SPRAY SYSTEM IS AVAILABLE	These cases are similar to RECSPRAYLT in that containment spray is ineffective at preventing containment failure. However, for these cases, AC power is available to support containment spray early. About 35% of the contributors including RECSPRAYLT also include the event MELT, which is addressed separately in this list. An additional 35% is related to containment over pressurization due to hydrogen burns. Installation of battery backed hydrogen igniters would reduce the contribution from these events (SAMA 19).
STREN1H2	5.00E-01	1.203	Likelihood That Cont Can Handle Comb. Gas Burn Press. W/ High Base Pressure	This event represents the cases where a hydrogen burn occurs, but the containment does not fail due to the burn event. Over 99.5% of these cases include the event MELT. As for the event MELT, over 50% of the cutset contributions including the event MELT are SBO events, which are represented by events RECOVERY-LOOP-03 and RECOVERY-LOOP-04. These events are addressed in the Level 1 importance list and the same SAMAs are applicable for MELT. An additional 20% to 25% of the contributors are cases where the SBO EDG is available, but cannot be aligned in time to prevent a seal LOCA. These cases are addressed by SAMA 1.
CTMT-F-BENIGN	9.00E-01	1.17	CONTAINMENT LEAK BEFORE BREAK	About 70% of the contributors including CTMT-F-BENIGN are related to hydrogen burns that fail containment. Installation of battery backed hydrogen igniters would reduce the contribution from these events (SAMA 19).
RECOVERY-LOOP-01	4.97E-01	1.158	NONRECOVERY OF OFFSITE POWER	Addressed by a similar event the Level 1 importance list.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
RECOVERY-LOOP-04	4.97E-01	1.141	NONRECOVERY OF OFFSITE POWER	Addressed by a similar event the Level 1 importance list.
GB-EDG-1B---DGFR	2.07E-02	1.136	DIESEL 1B FAILS TO RUN	Addressed by a similar event the Level 1 importance list.
DRYEFF	5.00E-01	1.127	Likelihood That Recombination Can Deplete Comb. Gas Given a Dry Cavity	This event represents the cases where the hydrogen recombiners are able to remove enough hydrogen to prevent a catastrophic burn. As a result, early containment failure does not occur, but subsequent evolutions result in loss of containment integrity. Over 99.5% of these cases include the event MELT. As for the event MELT, over 50% of the cutset contributions including the event MELT are SBO events, which are represented by events RECOVERY-LOOP-03 and RECOVERY-LOOP-04. These events are addressed in the Level 1 importance list and the same SAMAs are applicable for MELT. An additional 20% to 25% of the contributors are cases where the SBO EDG is available, but cannot be aligned in time to prevent a seal LOCA. These cases are addressed by SAMA 1.
GA-EDG-1A---DGFR	2.07E-02	1.127	DIESEL 1A FAILS TO RUN	Addressed by a similar event the Level 1 importance list.
NOSTREN1H2	5.00E-01	1.125	Likelihood That Cont Cannot Handle Comb. Gas Burn Press. W/ High Base Pressure	These contributors are related to hydrogen burns that fail containment (for late containment failure). Installation of battery backed hydrogen igniters would reduce the contribution from these events (SAMA 19).
GA-1A1BSBO-CDGFR	1.53E-04	1.118	EDG CCF Run DG-1A;DG-1B;DG-SBO	Addressed by a similar event the Level 1 importance list.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
EFEFP1------P7FR	5.06E-02	1.098	TURBINE-DRIVEN PUMP EF-P-1 FAILS TO RUN	Addressed by a similar event the Level 1 importance list.
NOEXSCRUBEFF	1.00E-01	1.096	Likelihood That Overlying Water Pool Will Not Scrub FPs Released From Corium	This event is completely linked to the event MELT; however, the population of MELT events that it is associated with are not SBO events. About 30% are related to RECOVERY-LOOP-01 for which SAMAs 1 and 2 would be useful. The remaining contributors are a diverse mixture of LOCAs and transients that would not be mitigated by a single SAMA outside of the installation of an additional, independent DHR/injection system. Based on the high cost of a new DHR/injection system and the low contribution of all non-SBO transients and non-ISLOCAs to the MACR, this type of change would not be cost beneficial. No additional SAMAs are suggested to address this event.
NODRYEFF	5.00E-01	1.09	Likelihood That Recombination Cannot Deplete Comb. Gas Given a Dry Cavity	These contributors are related to hydrogen burns that fail containment. Installation of battery backed hydrogen igniters would reduce the contribution from these events (SAMA 19).
NOAFTSTREN1	5.00E-01	1.08	Likelihood That Cont Cannot Handle Comb. Gas Burn Press. W/ High Base Pressure	These contributors are related to hydrogen burns that fail containment (for early containment failure). Installation of battery backed hydrogen igniters would reduce the contribution from these events (SAMA 19).
NOINERTAF	1.00E-01	1.08	Containment Has High Base Pressure Early After RV Failure Without Steam Inerting	These contributors are related to hydrogen burns that fail containment (for early containment failure). Installation of battery backed hydrogen igniters would reduce the contribution from these events (SAMA 19).

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
%LAIR	5.23E-03	1.08	LOSS OF AIR INITIATING EVENT	Addressed by a similar event the Level 1 importance list.
FLAG-SBOALIGN-1E	5.00E-01	1.074	SBO ALIGNED TO BUS 1E	Addressed by a similar event the Level 1 importance list.
JHHEF1-HBW1HEPOA	1.00E-04	1.073	EFHEF1_OPERH2HOA AND BWHBW1-----HP2OA	Addressed by a similar event the Level 1 importance list.
JHAHCD4RE27HEPOA	9.17E-05	1.07	AVHCD4_FF--HCDOA AND BWST-HRE27-HTKOA	Addressed by a similar event the Level 1 importance list.
%TRIB	2.86E-03	1.069	INITIATING EVENT FOR SGTR ON OTSG B	Addressed by a similar event the Level 1 importance list.
%TRIA	2.86E-03	1.069	INITIATING EVENT FOR SGTR ON OTSG A	Addressed by a similar event the Level 1 importance list.
GB-EG-Y-1B--DGMM	1.61E-02	1.069	Emergency Diesel Generator 1B in Maintenance	Addressed by a similar event the Level 1 importance list.
GB1BDG------DGFS	1.13E-02	1.066	DIESEL GENERATOR 1B FAILS TO START	Addressed by a similar event the Level 1 importance list.
GA-EG-Y-1A--DGMM	1.61E-02	1.065	Emergency Diesel Generator 1A in Maintenance	Addressed by a similar event the Level 1 importance list.
GA1ADG------DGFS	1.13E-02	1.062	DIESEL GENERATOR 1A FAILS TO START	Addressed by a similar event the Level 1 importance list.
WATEREFF	5.00E-01	1.061	Likelihood That Water in S/G Will Scrub Fission Products	This event is related to SGTR scenarios. The failure to provide makeup to the BWST (BWST-HRE27-HTKOA) contributes to over 85% of the cutsets including WATEREFF. Event BWST-HRE27-HTKOA is addressed in the Level 1 importance list.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
NONCGASHIGH	1.00E-01	1.057	Likelihood That Non Condensable Gas Production is Not High Given a Dry Cavity	This event is completely linked to the event MELT; however, the population of MELT events that it is associated with are not all SBO events. About 35% are related to RECOVERY-LOOP-03 and RECOVERY-LOOP-04, which are addressed by similar events in the Level 1 importance list. Some additional benefit (about 25%) could be gained through the use of the RBEC system to provide alternate flow to the DHR heat exchangers (DH-C-1A/B) (SAMA 3). The remaining contributors are a diverse mixture of LOCAs and transients that would not be mitigated by a single SAMA outside of the installation of an additional, independent DHR/injection system, which is known not to be cost effective. No additional SAMAs are suggested to address this event.
AV-LOCADV--HCDOA	1.00E+00	1.055	OPERATOR ACTION FAILURE TO LOCALLY OPERATE ADVS ON LOSS OF AIR	Addressed by a similar event the Level 1 importance list.
NOWATEREFF	5.00E-01	1.055	Likelihood That Water in S/G Will Not Scrub Fission Products	This event is related to SGTR scenarios. The failure to provide makeup to the BWST (BWST-HRE27-HTKOA) contributes to over 95% of the cutsets including WATEREFF. Event BWST-HRE27-HTKOA is addressed in the Level 1 importance list.
GSHEO1A----HDGOA	2.66E-02	1.051	OPERATOR FAILS TO STARTSBODG	Addressed by a similar event the Level 1 importance list.
LOCA-SIZE-101	7.80E-01	1.05	PROBABILITY THAT RCP SEAL LOCA IS OF VSLOCA CATEGORY	Addressed by a similar event the Level 1 importance list.
%VSB	2.56E-03	1.046	VERY SMALL BREAK LOCA	Addressed by a similar event the Level 1 importance list.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
%LNR	3.42E-03	1.044	LOSS OF NUCLEAR RIVER WATER	Addressed by a similar event the Level 1 importance list.
DABB1A------BYFD	4.84E-04	1.044	FAILURE OF BATTERY BANK 1A ON DEMAND	Addressed by a similar event the Level 1 importance list.
EF-CCFEFW-LETHAL	4.25E-04	1.043	LETHAL SHOCK TO THE EFW SYSTEM DUE TO COMMON CAUSE FAILURES	Addressed by a similar event the Level 1 importance list.
FLAG-SBOALIGN-1D	5.00E-01	1.041	SBO ALIGNED TO BUS 1D	Addressed by a similar event the Level 1 importance list.
NOHEATIML	1.00E-01	1.039	Prob. that Failure of the Primary System Does Not Occur Due to Heating	Over 86% of the contributors including this event are SBO scenarios, which are represented by events RECOVERY-LOOP-03 and RECOVERY-LOOP-04. These events are addressed in the Level 1 importance list and the same SAMAs are applicable for NOHEATIML.
GS-SBODG----DGFR	2.07E-02	1.038	SBO DIESEL FAILS TO RUN	Addressed by a similar event the Level 1 importance list.
GAEDG-STARTCDGFS	5.25E-05	1.037	EDG Fail to Start CCF DG-All 3	Addressed by a similar event the Level 1 importance list.
OP230KV-----OGFD	2.40E-03	1.034	LOSS OF 230KV TO AUX XFRMR 1A AND 1B	Addressed by a similar event the Level 1 importance list.
RARB-STANDBYFLAG	5.00E-01	1.034	BOTH DHRW TRAINS A AND B IN STANDBY	Addressed by a similar event the Level 1 importance list.
%LGA	1.23E-03	1.032	LOSS OF GA POWER	Addressed by a similar event the Level 1 importance list.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
INERTLT	1.00E-01	1.032	Sequence Late After RV Failure Has Low Base Pressure From Gas Generation	This event represents the cases where gas generation for the core melt process does not produce enough gas to create a high base pressure in the containment (related to evaluating consequences of a hydrogen burn). For the relevant cases (all RC8-01), the hydrogen burn does not cause containment failure, but subsequent evolutions result in loss of containment integrity. Over 99.8% of these cases include the event MELT. As for the event MELT, over 60% of the cutset contributions including the event MELT are SBO events, which are represented by events RECOVERY-LOOP-03 and RECOVERY-LOOP-04. These events are addressed in the Level 1 importance list and the same SAMAs are applicable for MELT. An additional 28% of the contributors are cases where the SBO EDG is available, but cannot be aligned in time to prevent a seal LOCA. These cases are addressed by SAMA 1.
INHINJ2_MUHHMUOA	1.00E+00	1.028	OPERATOR OPENS CROSS CONNECT VALVES MU-V-76A/B AND STARTS MU-P-1C	Addressed by a similar event the Level 1 importance list.
NON-RECOV-LNR-IE	2.70E-01	1.025	NON-RECOVERABLE FRACTION OF %LNR EVENTS	Addressed by a similar event the Level 1 importance list.
GADF-PALL6-CP2FS	3.62E-05	1.025	EDG Standby Pump CCF Start P2-ALL 6	Addressed by a similar event the Level 1 importance list.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
%ISL	1.80E-07	1.024	INTERFACING SYSTEM LOCA	For TMI-1, ISLOCA is dominated by DHR suction path failures after leak or rupture of valves DH-V-1 and DH-V-2. While the TMI-1 ISLOCA analysis does not take credit for any potentially mitigating actions, no actions that could reliably terminate the event are believed to be available. For example, 1) the isolation of DH-V-3 may not isolate the break or additional breaks may occur after isolation, 2) reduction of primary system pressure may reduce the flow out of the break, but it would not stop it, and 3) refill of the BWST does not place the plant in a stable state and the impacts of aux building flooding would have to be addressed. A potential SAMA would be to extend the high pressure boundary through valve DH-V-3 to allow an additional isolation point (SAMA 20).
ISLOCA--COREMELT	1.00E+00	1.024	CORE DAMAGE DUE TO INTERFACING SYSTEM LOCA	This event is completely tied to %ISL, which is treated separately on this list.
GA-1A-1B---CDGFR	2.31E-04	1.023	EDG CCF Run DG-1A;DG-1B	Addressed by a similar event the Level 1 importance list.
GS-EG-Y-4---DGMM	1.30E-02	1.023	SBO Diesel Generator in Maintenance	Addressed by a similar event the Level 1 importance list.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
CWNOLIMITLPME	1.00E-02	1.023	Plant Config and Layout Does Not Limit Material Reaching Cont. Wall With LPM	The contributors including this event are composed of a diverse set of accident scenarios that lead to low pressure core melts. No single SAMA has been identified that would effectively eliminate a majority of the core damage sequences. Several SAMAs identified in the Level 1 importance list are applicable to portions of the contributors, but these issues are addressed by the Level 1 review and no new insights are available from the Level 2 cutsets for the core damage evolutions. The event CWLIMITLPME represents the probability that corium will not spread to the containment wall after a low pressure melt, which is described as "almost certain" in the L2 analysis based on the cavity configuration. The event here, CWNOLIMITLPME, is the complement of CWLIMITLPME. A possible plant enhancement would be to identify pathways that corium could reach the containment wall and to install shields to block the pathways or to flood the containment early (SAMA 21).
MF-MFPT----EVENT	2.09E-02	1.022	MFPT (LEGACY EVENT)	These events are related to the loss of MFW flow in after a trip when overcooling events have not occurred. MFW and EFW availability are important to determining the status of fission product scrubbing for SGTR events and also for determining whether or not induced tube ruptures will occur. These events could be reduced in an independent AFW system were installed (SAMA 22).
%SLT	4.22E-03	1.022	STEAM LINE BREAK IN TURBINE BUILDING	Addressed by a similar event the Level 1 importance list.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
HP-_14A_14BCVAFD	2.03E-04	1.021	HPI Train Fails MOV CCF Op MU-V-14A;14B	Addressed by a similar event the Level 1 importance list.
%LNS	2.74E-03	1.021	LOSS OF NUCLEAR SERVICES CLOSED COOLING WATER	Addressed by a similar event the Level 1 importance list.
%FW	5.40E-02	1.02	LOSS OF FEEDWATER	These events are related to the loss of MFW flow in after a trip followed by failure of EFW and induced SGTR. MFW and EFW availability are important to determining the status of fission product scrubbing for SGTR events and also for determining whether or not induced tube ruptures will occur. These events could be reduced in an independent AFW system were installed (SAMA 22).
GSEG-Y-4----DGFS	1.13E-02	1.02	STATION BLACKOUT DG FAILS TO START	Over 99% of the contributors including this event are SBO scenarios, which are represented by events RECOVERY-LOOP-03 and RECOVERY-LOOP-04. These events are addressed in the Level 1 importance list and the same SAMAs are applicable for GSEG-Y-4----DGFS.
CFRR-V-6----VCFF	1.62E-02	1.018	RR-V6 FAILS TO OPERATE	This valve failure is related to the loss of RBEC return flow for containment cooling. The TMI-1 HRA documentation indicates that there are no alarm response procedures related to low flow on the system that would direct the operators to open the bypass valve (RR-V-5) when RR-V-6 fails to open. A potential SAMA would be to develop procedures to direct operation of the bypass valve when the normal return path fails (SAMA 23).

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
CFHRR1-----HVAOA	7.79E-01	1.018	OPERATOR FAILS TO OPEN MOV RR-V-5	This valve failure is related to the loss of RBEC return flow for containment cooling. The TMI-1 HRA documentation indicates that there are no alarm response procedures related to low flow on the system that would direct the operators to open the bypass valve (RR-V-5) when RR-V-6 fails to open. A potential SAMA would be to develop procedures to direct operation of the bypass valve when the normal return path fails (SAMA 23).
RECOVERY--LNR-IE	7.30E-01	1.018	RECOVERABLE FRACTION OF %LNR EVENTS	Addressed by a similar event the Level 1 importance list.
JHHRE27HL1AHEPOA	2.00E-04	1.017	BWST-HRE27-HTKOA AND DLHHL1A----HVHOA	Automating BWST refill would effectively eliminate this JHEP and provide a reliable means of maintaining level in the BWST (SAMA 10).
NORECOFFSITEPWR	3.60E-02	1.017	OFFSITE POWER NOT RECOVERED WITHIN 24 HOURS	Most of the contributors including this event result in late containment failure due to over pressurization. Over 70% of the contributors are SBO cases, which are represented by events RECOVERY-LOOP-03 and RECOVERY-LOOP-04. These events are addressed in the Level 1 importance list and the same SAMAs are applicable for NORECOFFSITEPWR.
BWHBW1-----HP2OA	2.18E-03	1.017	OPERATOR FAILS TO INITIATE HPI	Addressed in the Level 1 importance list through dependent operator action terms JHHEF1-HBW1HEPOA and JHHAMHEFHBWHEPOA.
JHHOT1-XTIEHEPOA	5.10E-02	1.017	OTHOT1_RCPTHP1OA AND NR-NRSRXTIEHVAOA	Automating RCP trip on high cooling water temperature would effectively eliminate this JHEP and provide a reliable means of preventing pump/seal damage (SAMA 8).

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
GEOMFREEZE	5.00E-01	1.016	Cavity Geometry Allows Enough Corium to Disperse For Freezing	Over 87% of the contributors including this event are SBO scenarios, which are represented by events RECOVERY-LOOP-03 and RECOVERY-LOOP-04. These events are addressed in the Level 1 importance list and the same SAMAs are applicable for GEOMFREEZE. No potentially cost effective containment structure changes to impact the dispersal of corium in the cavity have been identified.
JHHHL1AHSR2HEPOA	2.00E-04	1.016	DLHHL1A----HVHOA AND SAHSR2----HSROA	Addressed by a similar event the Level 1 importance list.
BWST-HRE27-HTKOA	2.65E-02	1.015	FAILURE TO REFILL BWST (SPLIT FRAC REV)	Addressed in the Level 1 importance list through dependent operator action JHAHCD4RE27HEPOA.
INMU-P-1C--HMUOA	1.00E+00	1.014	OPERATOR FAILURE TO ALIGN AND START MU-P-1C	Addressed by a similar event the Level 1 importance list.
CTMT-F-NOTBENIGN	1.00E-01	1.014	PROBABILITY THAT CONTAINMENT FAILURE IS NOT BENIGN	This event represents the probability that containment failure due to over pressurization will be a failure that results in a rapid blowdown of containment. Over 80% of the contributors including CTMT-F-NOTBENIGN are failure due to hydrogen burns. Installation of battery backed hydrogen igniters would reduce the contribution from these events (SAMA 19).
%SBL	4.50E-04	1.014	SMALL BREAK LOCA	Addressed by a similar event the Level 1 importance list.
JHHAM2-HEF1HEPOA	4.61E-03	1.014	AMHAM2-----HC1OA AND EFHEF1_OPERH2HOA	This dependent operator action term is addressed by SAMA 13, which would automate operator action AMHAM2-----HC1OA and preclude the need for EFHEF1_OPERH2HOA. No additional SAMAs are required.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
HADC-V-2A---VCFT	3.00E-03	1.013	DC-V2A FAILS TO REMAIN OPEN	Addressed by a similar event the Level 1 importance list.
HADC-V-65A--VCFT	3.00E-03	1.013	DC-V65A TRANSFERS TO DIFFERENT STATE	Addressed by a similar event the Level 1 importance list.
HP-MU-P-1B--P2MM	7.46E-03	1.012	Makeup Pump (Operating) 1B in Maintenance	Addressed by a similar event the Level 1 importance list.
DXBATT1A1B-CBYFF	3.51E-06	1.012	Batteries 1A and 1B CCF Operate	The importance of this event is driven by its contribution to containment isolation failure in SBO cases (dominated by RECOVERY-LOOP-04), which is dependent on AC power. These sequences could be mitigated by preventing core damage in the same manner as suggested for RECOVERY-LOOP-04.
DX-1-ABCD--CBCFF	3.39E-06	1.012	Battery Charger CCF of 3/4 and 4/4	The importance of this event is driven by its contribution to containment isolation failure in SBO cases (dominated by RECOVERY-LOOP-04), which is dependent on AC power. These sequence could be mitigated by preventing core damage in the same manner as suggested for RECOVERY-LOOP-04.
JHHOTHMRXTIHEPOA	3.10E-03	1.011	OTHOT1_RCPTHP1OA; MRHMR1-----HMUOA; NR-NRSRXTIEHVAOA	Addressed by a similar event the Level 1 importance list.
%RT	4.82E-01	1.011	REACTOR TRIP	The importance of this event is driven by a diverse set of contributors that are addressed elsewhere in the importance lists, including OP230KV-----OGFD, MELT, RECOFFSITEPWR, and RECSPRAYLT. No single, potentially cost beneficial SAMA has been identified to mitigate all of the risk associated with the “reactor trip” initiating event.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
HA-P-1AP-1BCP2FS	1.50E-04	1.011	DH Clsd Cool Stdby Pmp CCF Strt P2-1A;1B	Addressed by a similar event the Level 1 importance list.
NRHNS8A----HP1OA	5.37E-01	1.011	OPERATOR FAILS TO ISOLATE FAILED RW PUMP (POWER UNAVAILABLE)	Addressed by a similar event the Level 1 importance list.
GADF-PALL6-CP2FR	1.60E-05	1.011	EDG Standby Pump CCF Run P2-ALL6	Over 99.5% of the contributors including this event are SBO scenarios, which are represented by events RECOVERY-LOOP-03 and RECOVERY-LOOP-04. These events are addressed in the Level 1 importance list and the same SAMAs are applicable for GADF-PALL6-CP2FR.
OP-OPB-CONDITION	3.00E-01	1.011	POWER SUPPLY UNAVAILABLE GIVEN A TURBINE BYPASS SIGNAL	Addressed by a similar event the Level 1 importance list.
NRNR-V-20A--VPFD	1.35E-03	1.011	CHECK VALVE NR-V20A FAILS TO RESEAT	Addressed by a similar event the Level 1 importance list.
HA-DC-P-1A--P1MM	2.84E-03	1.011	Decay Heat Closed Cycle Cooling Water Pump 1A in Maintenance	Addressed by a similar event the Level 1 importance list.
GSFS-V-646--VCFD	6.38E-03	1.01	AIR OPERATED VALVE FS-V-646 FAILS ON DEMAND	This event causes the failure of the cooling flow to the SBO EDG and over 99.5% of the contributors including this event are SBO scenarios, which are represented by events RECOVERY-LOOP-03 and RECOVERY-LOOP-04. These events are addressed by similar events in the Level 1 importance list and the same SAMAs are applicable for GSFS-V-646--VCFD.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
GSFS-V-647--VCFD	6.38E-03	1.01	AIR OPERATED CONTROL VALVE FS-V-647 FAILS ON DEMAND	This event causes the failure of the cooling flow to the SBO EDG and over 99.5% of the contributors including this event are SBO scenarios, which are represented by events RECOVERY-LOOP-03 and RECOVERY-LOOP-04. These events are addressed in the Level 1 importance list and the same SAMAs are applicable for GSFS-V-647--VCFD.
HADC-P-1A---P2FS	2.46E-03	1.01	DHCCW PUMP DC-P1A FAILS TO START	Addressed by a similar event the Level 1 importance list.
HBDC-V-2B---VCFT	3.00E-03	1.01	DC-V2B FAILS TO REMAIN OPEN	Addressed by a similar event the Level 1 importance list.
HBDC-V-65B--VCFT	3.00E-03	1.01	DC-V65B TRANSFERS TO DIFFERENT STATE	Addressed by a similar event the Level 1 importance list.
JHHAMHEFHBWHEPOA	2.40E-04	1.01	JHHAM2-HEF1HEPOA AND BWHBW1-----HP2OA	Addressed by a similar event the Level 1 importance list.
SPARKAFT_1	1.00E-01	1.01	PROB THAT SPARK IS AVAILABLE EARLY AFTER RV FAILURE WITHOUT RB SPRAY	These cases are related to evolutions in which an ignition source is available and causes a non-catastrophic hydrogen burn. Containment failure occurs later due primarily to basemat failures. For the contributors including this event, most of the contribution results from core damage events that could have been mitigated if it were possible to swap the train to which the SBO EDG was aligned after equipment failure. This is addressed by SAMA 1.

TABLE E.5-2
LEVEL 2 IMPORTANCE LIST REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
DABATTCHGR-HBCOA	1.00E-01	1.01	HEP FOR FAILURE TO ALIGN SPARE CHARGER 1E OR 1F	About 80% of the contributors including DABATTCHGR-HBCOA are LOOP events that include events RECOVERY-LOOP-01 and RECOVERY-LOOP-04. These events are addressed in the Level 1 importance list and the same SAMAs are applicable for DABATTCHGR-HBCOA.
CWNOLIMITHPME	1.00E-01	1.01	Plant Config and Layout Does Not Limit Material Reaching Cont. Wall With HPM	About 70% of the contribution from this event is linked to "AV-LOCADV--HCDOA", which is addressed by a similar event the Level 1 importance list. As discussed there, if existing procedures are credited, the contribution from AV-LOCADV--HCDOA will be greatly reduced, which implies that event CWNOLIMITHPME would not remain above the RRW review threshold of 1.01. However, SAMA 21 was developed for a similar event (CWNOLIMITLPME) and it addresses the same issues relevant to CWNOLIMITHPME.
HB-DC-P-1B--P1MM	2.84E-03	1.01	Decay Heat Closed Cycle Cooling Water Pump 1B in Maintenance	Addressed by a similar event the Level 1 importance list.
EF-EF-P-1---P1MM	6.57E-03	1.01	EFW Pump (Turbine Driven) 1 in Maintenance	About 90% of these events are SBO cases, represented by RECOVERY-LOOP-04. This event is addressed in the Level 1 importance list and the same SAMAs are applicable for EF-EF-P-1---P1MM.

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
1	Enhance the SBO EDG for Auto Alignment and Loading	The current capability of the SBO EDG is limited by manual actions to diagnose and respond to conditions requiring a start of the SBO EDG. While the time required to start and load the EDG is relatively short, it is close enough to the 13 minute limit for restoration of seal cooling after a total loss that no credit is taken for the SBO EDG to prevent seal LOCAs in LOOP evolutions with normal EDG failures. Automation of SBO EDG operation would reduce the time required to restore seal cooling and through this function, a large portion of the seal LOCA CDF could be eliminated.	Level 1 TMI-1 Importance List	The cost of this enhancement was estimated to be $3,125,000 by the TMI staff (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.1).

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
2	Install Damage Resistant, High Temperature RCP Seals with a Portable 480V Generator for Extended EFW Operation	Currently, alternate RCP pump seals are available that can effectively prevent seal LOCAs caused by loss of RCP seal cooling (Flowserve N-9000 seals). It is estimated that these seals will limit leakage flow to about 1 gpm per seal on loss of cooling, which is low enough to maintain core coverage in cases where seal LOCAs would normally result in core uncovery/core damage within the PRA's 24 hour mission time. The ability to prevent a seal LOCA will allow for extended operation in SBO conditions if level instrumentation can be supplied using the vital 120V AC system. Powering the station battery chargers with a portable 480V AC generator would provide this capability and allow control of the TD EFW system to be retained in the MCR.	Level 1 TMI-1 Importance List	The cost of this enhancement was estimated to be $7,300,000 by the TMI staff (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.2).

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
3	Use NSCCW as an Alternate Cooling Source for the DHR Heat Exchangers (DH-C-1A/B)	For LOCAs requiring heat removal with the RHR system, DHRW and DHCCW failures are large contributors to loss of the primary cooling function. Providing the ability to cross-tie the NSCCW system to the DHR heat exchangers would diversify the plant's heat removal capability and eliminate the failures associated with loss of DHRW or DHCCW flow. The hard piped connections are assumed to be sized to allow enough flow to remove decay heat (not just pump cooling loads) and that each division is provided with a cross-connection.	Level 1 TMI-1 Importance List	The cost of this enhancement was estimated to be $2,450,000 by the TMI staff (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.3).

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
4	Provide Alternate Power to HPI Pump Minimum Flow Recirculation Valves MU-V-36 and MU-V-37	The current PRA model logic correctly assumes isolation of valves MU-V-36 and 37 on an ESAS, but it does not include the AC power dependences for the "close" action. However, the logic related to opening the minimum flow valves does include the power dependences, which can result in the generation of cutsets that include the failure to open a flow path that was never isolated. If the appropriate power dependencies were accounted for in the isolation logic, the only events that could cause the MU-V-36 or MU-V-37 valves to be "stranded closed" are those in which an ESAS occurs when both divisions of power are available and then division "A" power fails before MU-V-36 can be opened.	Level 1 TMI-1 Importance List	Not Required (screened on PRA insights).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis(refer to Section E.6.4).

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
5	Enhance Valves MU-V-76A/B and MU-V-77A/B to Allow for Rapid Alignment Changes in Accident Conditions	The current MU-V-76A/B and MU-V-77A/B valve configurations do not allow for rapid re-alignment during accident conditions. For TMI-1, the capability to quickly align the "C" HPI pump for seal injection would reduce the risk of prominent accident sequences in which thermal barrier cooling has failed in conjunction with the "A" and "B" HPI pumps. Replacing MU-V-76A/B and MU-V-77A/B with MOVs operable from the main control room would allow TMI-1 to use the "C" HPI pump for seal injection and prevent seal LOCAs when the normal cooling methods are unavailable.	Level 1 TMI-1 Importance List	The cost of this enhancement was estimated to be $3,150,000 by the TMI staff (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.5).
6	Add Cross-ties Within the Trains of the Cooling Systems -DHR -DHRW -DHCCW	Some failure combinations that eliminate both trains of the DHR related cooling systems could be mitigated if cross-ties were available between trains of the DHR, DHRW, and DHCCW systems (not between the systems). For example, these cross-ties would be helpful in conditions where the flow path fails in one train while a pump failure or maintenance event disables the opposite train. To ensure the DHR cross-ties can be implemented in a timely manner for LPI requirements, the associated valves should be operable from the main control room.	Level 1 TMI-1 Importance List	The cost of installing the powered DHR cross-tie was estimated to be $2,750,000 by the TMI staff (Exelon 2007c). The cross-ties for the DHCCW and DHRW systems are not required to be MOVs due to the longer times available for performing the cross-tie and while there would be a substantial additional cost related to the addition of these cross-ties, only the DHR cross-tie cost of $2,750,000 is used here based on the availability of information.	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.6).

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
7	Use Fire Service Water as an Alternate Cooling Source for the ICCW Heat Exchangers	For cases in which NSRW is unavailable due to hardware failures (e.g., flow diversion), the Fire Service Water system could be used to directly cool the ICCW heat exchangers for thermal barrier cooling support. Given that the ICCW pumps would be available for the relevant cases, a local, manual valve could be used for the alignment as time should be available for such an action.	Level 1 TMI-1 Importance List	Palisades estimated $2.9 million for Fire water cooling to CCW HXs (NMC 2005), Calvert Cliffs estimated $565k for alt DHR cooling (BGE 1998), and Brown's Ferry estimated $1 million for Fire Water to DHR HXs (TVA 2003). The Brown's Ferry estimate is used for TMI.	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.7).
8	Automate Reactor Coolant Pump Trip	Seal LOCAs resulting from operator failures to trip the RCPs on loss of motor bearing cooling could be reduced if high temperature sensors were installed on motor bearing cooling water lines to provide automatic trip signals.	Level 1 TMI-1 Importance List	The cost of this enhancement was estimated to be $145,000 by the TMI staff (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.8).
9	Proceduralize Local ADV Operation	TMI-1 has procedures to perform the local ADV operations that are not credited in the PRA model (the failure probability is set to 1.0). If the available procedures are credited, the RRW value of the operator action would be reduced below the SAMA review threshold. This SAMA is used demonstrate the reduction in the RRW that would occur when a reasonable failure probability is applied to the operator action.	Level 1 TMI-1 Importance List	Not Required (screened on PRA insights).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.9).

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
10	Automate BWST Refill	Failure to refill the BWST is a large contributor to some SGTR sequences, especially those in which the MS ADVs fail to operate. Automating the refill function would improve the reliability of this process and reduce the contributions from prominent SGTR sequences by providing a long term high pressure injection source. This SAMA requires a new pump with a flow rate of at least 400 gpm with a connection to a borated water source that will provide suction for 24 hours. In addition, the pump should be able to supply water from a non-borated water source for an indefinite periods of time after depletion of the borated water source.	Level 1 TMI-1 Importance List	The cost of this enhancement was estimated to be $3,800,000 by the TMI staff (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.10).
11	Enhance Extreme External Flooding Mitigation Equipment to Address SBO and Loss of Seal Cooling Scenarios	Making the extreme flooding equipment useful for SBO conditions, especially those with TD EFW failure, would require permanently mounting the submersible pumps so that the suctions could easily be swapped from a piped water source to the flood water source. Permanently installing the portable generator and the pumps so that they could be aligned from the MCR would improve alignment capabilities and address non-SBO loss of seal cooling cases through the ability to rapidly align alternate seal cooling.	Level 1 TMI-1 Importance List	The cost of this enhancement was estimated to be $4,250,000 by the TMI staff (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.11).

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
12	Use the DHR System as an Alternate Suction Source for HPI	Failures of the BWST suction path to the HPI pumps will lead to core damage in scenarios requiring early makeup. Through implementation of procedure changes, the DHR system could be aligned to take suction from the BWST and supply flow to the HPI system to allow injection in these cases.	Level 1 TMI-1 Importance List	This change can be implemented at TMI-1 through only procedure changes as no interlocks are associated with the suggested alignment. Procedure changes are estimated to cost about $50,000 (CPL 2004).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.12).
13	Change IA System Logic to Automatically Start IA-P-1A/B After a Low Voltage Trip in Conjunction with an ESAS	The current IA system logic requires the operators to re-load the IA compressors on emergency power after a low voltage trip when an ESAS is registered. Automating the re-loading of these compressors would remove the requirement for the operators to perform this task in accident conditions.	Level 1 TMI-1 Importance List	The cost of this enhancement was estimated to be $950,000 by the TMI staff (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.13).

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
14	Replace HPI Pump Cooling Alignment Valves with MOVs	In the event that the normally aligned cooling source to a HPI pump fails, the current plant configuration requires local operation of the valves to swap the pump to the alternate cooling source. The time required to perform this action is considered to preclude it as a means of both preventing seal LOCAs in loss of seal cooling evolutions and for providing high pressure makeup. Replacing the valves with MOVs would allow the operators to rapidly align the alternate cooling source from the MCR in time to prevent a seal LOCA or provide high pressure injection.	Level 1 TMI-1 Importance List	The cost of this enhancement was estimated to be $3,150,000 by the TMI staff (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.14).

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
15	Automate Swap to Recirculation Mode	The operator action to swap to recirculation mode is a key action for LOCA scenarios. Automating this function would improve the reliability of this action, especially in the rapidly evolving events where other actions are competing for the attention of the operators.	Level 1 TMI-1 Importance List	Multiple SAMA analyses have included estimates for this type of change, but the estimates vary by over a factor of 3.5: - Oconee estimated the cost at over $1 million per unit (DUKE 1998)) - Point Beach estimated the cost at over $1 million per unit (NMC 2004) - Catawba estimated the cost at over $1 million (DUKE 2001) - Turkey Point estimated the cost to be about $450,000 (per unit) (FPL 2000) - H.B. Robinson $265,000 (single unit) (CPL 2002) For TMI-1, the $450,000 estimate from Turkey Point is used as it is in the middle range of the industry estimates identified.	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.15).
16	Automate HPI Injection on Low Pressurizer Level	Providing an automatic signal to initiate HPI on low pressurizer level would improve the reliability of HPI initiation.	Level 1 TMI-1 Importance List	The cost of this enhancement was estimated to be $1,100,000 by the TMI staff (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.16).

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
17	Auto Isolate Steam Generators on High Steam Line Flow	For steam line breaks downstream of the MSIVs, failure to isolate the relevant steam generator is an important contributor to core damage. The addition of logic to isolate the steam generator on high steam line flow would reduce the core damage contribution from isolation failures.	Level 1 TMI-1 Importance List	This SAMA is considered to be similar in scope to SAMA 13 and the same cost of implementation ($950,000) is used for this SAMA.	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.17).
18	Provide the Capability to Align the Standby Battery Charger and the 1A/1B Cross-tie from the MCR	TMI has a spare 125V DC battery charger for each division that can be aligned to either battery bank within a division in the event that a normally operating battery charger fails. Currently, the alignment requires local actions. There is typically adequate time to align the charger in the event of a failure, but additional changes could be made to allow rapid alignment of the spare charger from the MCR to reduce the manipulation time and improve the man-machine interface.	Level 1 TMI-1 Importance List	No plant specific implementation cost was developed for this SAMA. Based on the low impact of the SAMA, the $100,000 minimum cost of a hardware modification (Exelon 2003) is used as the implementation cost.	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.18).
19	Install Battery Backed Hydrogen Igniters or a Passive Hydrogen Ignition System	The addition of igniters would provide a means of preventing catastrophic combustible gas burns by continuously burning these gases before they reach critical levels. Providing battery backup power would increase the likelihood that this system would be available in LOOP events. Use of a passive system would also function in LOOP as well as long term SBO scenarios.	Level 2 TMI-1 Importance List	The cost of this enhancement was estimated to be $760,000 in the Calvert Cliffs SAMA analysis (BGE 1998).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.19).

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
20	Extend the High Pressure Boundary Through DHR Valve DH-V-3 for ISLOCA Isolation	The highest frequency ISLOCA scenario for TMI-1 is through two valves in the DHR suction line. While the scenario's CDF is low, the release frequency is relatively high given that primary containment is bypassed by definition. No effective mitigating actions are considered to be available in these cases because 1) the break may occur upstream of DH-V-3 or additional breaks in the low pressure boundary may occur after closure of a low pressure isolation valve, 2) reduction of primary system pressure may reduce the flow out of the break, but it would not stop it, and 3) refill of the BWST does not place the plant in a stable state and results in auxiliary building flooding. Extending the pressure boundary through DH-V-3 would provide an additional isolation point in these cases.	Level 2 TMI-1 Importance List	The cost of this enhancement was estimated to be $3.030,000 by the TMI staff (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.20).

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
21	Install Concrete Shields to Block Direct Pathways from the RPV to the Containment Wall and/or Direct Containment Flooding Early in External Flooding Scenarios	This SAMA is based on a failure mode identified in the Level 2 analysis that indicates corium ejection during RV failure could result in dispersal of debris such that it could directly interact with the containment wall and cause a failure of the wall. For some external flooding scenarios, it may be possible to change the procedures to direct containment flooding early such that water would be available on the containment floor before loss of power.	Level 2 TMI-1 Importance List	The cost of this enhancement was estimated to be $1,200,000 by the TMI staff (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.21).
22	Install an Independent AFW System	For TMI-1, loss of MFW after a trip coupled with loss of EFW can lead to large radionuclide releases in SGTR and induced SGTR scenarios due to the unavailability of water in the SGs for fission product scrubbing. A large contributor to EFW failure is estimated to be system wide common cause failures. An independent, motor driven, auxiliary feedwater system would be an effective means of addressing these cases. Power dependence is not a large issue for the cases addressed by this SAMA and the independent EFW pump is assumed to be powered by existing emergency power such that it would not be capable of mitigating SBO scenarios.	Level 2 TMI-1 Importance List	Calvert Cliffs estimated the cost of installing an additional HPSI pump with a dedicated diesel to be between $5 million and $10 million (BGE 1998). This type of enhancement is similar is scope to the changes required for this SAMA and the lower bound estimate of $5 million is used for this SAMA as the diesel generator is not required for this SAMA.	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.22).

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
23	Develop Alarm Response Procedures to Direct Operation of RR-V-5 on Low RBEC Flow	Failure of RR-V-6 to open results in the loss of RBEC flow to the reactor building coolers, which can be diagnosed using the system flow indicators in the main control room; however, no alarm response procedures exist to specifically direct operation of the bypass valve (RR-V-5). If this procedure was developed, it may reduce the diagnosis time and improve the reliability of this operator action in an accident conditions.	Level 2 TMI-1 Importance List	Procedure changes are estimated to be $50,000 (CPL 2004).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.23).

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
24	Install Damage Resistant, High Temperature RCP Seals with a Diesel Engine as an Alternate Drive for an EFW Pump and a Portable Generator for Level Control Instrumentation	For SBOs in which EFW has failed, neither primary nor secondary side cooling is available. Installing the enhanced RCP seals will prevent seal LOCAs and use of a portable generator would allow the turbine driven EFW pump to be used for extended periods in an SBO, as suggested in SAMA 2. However, in the event that the turbine driven EFW pump fails, there would be no means of providing secondary side makeup. Turbine driven EFW failures could be mitigated if an engine was available to drive one of the EFW pumps. Other industry SAMA applications have suggested similar strategies, but they typically suggest the turbine driven pumps as the best option for connection to the engine based on ease of connection. For scenarios with turbine driven EFW failure, however, the initial TD EFW pump failure may prevent its further use even with an alternate motive source. As a result, this SAMA, in addition to the requirements of SAMA 2, requires that the diesel engine be connected to one of the motor driven EFW pumps.	Palisades SAMA Analysis (NMC 2005)	The cost of implementation for this SAMA is estimated to be a combination of SAMA 2 ($7,300,000) and the $1.1 million estimate for a direct drive diesel injection pump from Palisades (NMC 2005). The total implementation cost is $8,400,000.	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.24).

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
25	Install an Additional EDG	An additional source of AC power is a potential means of supplying an entire division of safety equipment in the event that on-site AC power is lost in a LOOP. While additional EDGs are expensive, they can be cost effective at some plants, especially those with a large LOOP/SBO contribution to CDF.	Palisades SAMA Analysis (NMC 2005)	Brown's Ferry estimated the cost of installing an additional EDG to be $6 million (TVA 2003). While there are estimates as high as $25 million used in SAMA analyses for the installation of additional EDGs, the Browns Ferry estimate is used for TMI-1.	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.25).
26	Reroute Cables so that They Do Not Pass Over Ignition Sources in Fire Area CB-FA-2e (West Inverter Room) or Wrap them in Fire Proof Material	Some of the risk from fires in this room is from damage to cables that run over ignition sources. If the cable trays were re-routed away from the electrical equipment that they currently pass over, the consequences of equipment fires in the inverter room could be reduced.	TMI-1 IPEEE (Fire)	Of the two options, cable wrapping was determined to be the more cost effective approach. The cost of performing the cable wrapping in CB-FA-2e was estimated to be $900,000 by the TMI staff (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.26).
27	Improve the 480V AC load center welds	The IPEEE determined that the existing 480V AC load centers were among the weaker components in the TMI-1 AC distribution system. Adding reinforcements to the welds on the load center framework would improve the seismic durability of the structure and increase the likelihood that the system would be available after a seismic event. The other low seismic capacity components, the EDG air receivers, were enhanced subsequent to the completion of the IPEEE.	TMI-1 IPEEE (Seismic)	The cost of this enhancement was estimated to be $575,000 by the TMI staff (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.27).

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
28	Improve the Decay Heat Service Cooler (DC-C-2A/B) Anchorages	The IPEEE determined that the existing Decay Heat Service Coolers (DC-C-2A/B) lacked sufficiently durable anchorages. Replacing the anchorages with more robust anchorages would improve the seismic durability of the structure and increase the likelihood that the heat exchangers would be available after a seismic event.	TMI-1 IPEEE (Seismic)	The cost of this enhancement was estimated to be $575,000 by the TMI staff (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.28).
29	Replace EDG Ground Resistors	Failure of the EDG ground resistors results in failure of the EDGs, which will lead to core damage in the event that off-site power is not available. Given that the HCLPF capacity for these components was estimated at 0.25g compared with 0.09g capacities of off-site power components (such as the 1/A and 1/B distribution buses or the aux transformers), it is likely that core damage will ensue due to long term loss of power if the EDG ground resistors fail from seismic shock. Replacing the resistors with more durable versions would improve the reliability of the EDGs in seismic events.	TMI-1 IPEEE (Seismic)	The cost of this enhancement was estimated to be $800,000 by the TMI staff (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.29).

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
30	Improve Diesel Fire Pump Fuel Oil Tank and Battery Rack Supports	The Fire Service Water system provides cooling to the SBO EDG, backup cooling the DHCCW heat exchangers, and backup cooling to the "1A" and "1B" Instrument Air compressors. While seismic failures to the systems FSW supports would likely limit the benefit of improving the fuel oil tank and battery racks, some benefit may be available through improvements to the diesel fire pump's reliability.	TMI-1 IPEEE (Fire/Seismic)	The cost of this enhancement was estimated to be $150,000 by the TMI staff (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.30).

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
31	Modify Specific Containment Penetration MOVs to “Fail Closed”	Most containment penetrations have AOV or SOV isolation valves that will fail closed on loss of air or power; however, there are cases in which MOVs are used instead. Those lines that do not include a pair of AOVs or SOVs that fail closed are typically below 1" in diameter or include at least one AOV or SOV that will fail closed on loss of air or power. However, the NSCCW and RBEC systems include penetrations that only include MOVs. While these are closed cooling systems that would not normally provide a credible release path, heat exchanger breaks in seismic events could provide containment bypass routes in the event that a failure also occurs in the reactor building. Changing one of the valves in each of these paths to fail closed is a means of increasing the isolation probability over what is available from manual action.	TMI-1 IPEEE (Seismic)	The cost of this enhancement was estimated to be $4,100,000 by the TMI staff (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.31).

TABLE E.5-3
PHASE I SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
32	Pre-stage Severe Flooding Equipment	Pre-staging the equipment used to prevent core damage in severe flooding conditions would reduce sources of error in the alignment actions and reduce the time required to perform the task. Potential changes include: - Storing the portable EDG on the turbine deck - Adding a normally empty fuel oil tank for the portable EDG to the turbine deck - Permanently running power cable from the portable EDG to the pump areas A potential permutation of this SAMA would be to procure an additional portable EDG to reduce the failure contribution from the power source.	TMI-1 IPEEE (External Flooding)	The cost of implementation is estimated to be $1,700,000 (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.32).
33	Increase the Flood Protection Height	The current configuration protects to the design basis limit of 310 feet msl and levels any higher result in topping of the existing flood doors and flooding of sensitive areas. Raising the height of the flood doors (or completely sealing the doors) would prevent water incursion and allow for continued operation of the normal safety equipment.	TMI-1 IPEEE (External Flooding)	The cost of this enhancement was estimated to be $2,700,000 by the TMI staff (Exelon 2007c).	Cannot be screened on cost or applicability to the plant. Retain for Phase II analysis (refer to Section E.6.33).

TABLE E.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	BASELINE PHASE II DISPOSITION
1	Enhance the SBO EDG for Auto Alignment and Loading	The current capability of the SBO EDG is limited by manual actions to diagnose and respond to conditions requiring a start of the SBO EDG. While the time required to start and load the EDG is relatively short, it is close enough to the 13 minute limit for restoration of seal cooling after a total loss that no credit is taken for the SBO EDG to prevent seal LOCAs in LOOP evolutions with normal EDG failures. Automation of SBO EDG operation would reduce the time required to restore seal cooling and through this function, a large portion of the seal LOCA CDF could be eliminated.	Level 1 TMI-1 Importance List	This SAMA's net value is negative and is classified as "not cost beneficial".
2	Install Damage Resistant, High Temperature RCP Seals with a Portable 480V Generator for Extended EFW Operation	Currently, alternate RCP pump seals are available that can effectively prevent seal LOCAs caused by loss of RCP seal cooling (Flowserve N-9000 seals). It is estimated that these seals will limit leakage flow to about 1 gpm per seal on loss of cooling, which is low enough to maintain core coverage in cases where seal LOCAs would normally result in core uncovery/core damage within the PRA's 24 hour mission time. The ability to prevent a seal LOCA will allow for extended operation in SBO conditions if level instrumentation can be supplied using the vital 120V AC system. Powering the station battery chargers with a portable 480V AC generator would provide this capability and allow control of the TD EFW system to be retained in the MCR.	Level 1 TMI-1 Importance List	This SAMA's net value is negative and is classified as "not cost beneficial".

TABLE E.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	BASELINE PHASE II DISPOSITION
3	Use NSCCW as an Alternate Cooling Source for the DHR Heat Exchangers (DH-C-1A/B)	For LOCAs requiring heat removal with the RHR system, DHRW and DHCCW failures are large contributors to loss of the primary cooling function. Providing the ability to cross-tie the NSCCW system to the DHR heat exchangers would diversify the plant's heat removal capability and eliminate the failures associated with loss of DHRW or DHCCW flow. The hard piped connections are assumed to be sized to allow enough flow to remove decay heat (not just pump cooling loads) and that each division is provided with a cross-connection.	Level 1 TMI-1 Importance List	This SAMA's net value is negative and is classified as "not cost beneficial".
4	Provide Alternate Power to HPI Pump Minimum Flow Recirculation Valves MU-V-36 and MU-V-37	The current PRA model logic correctly assumes isolation of valves MU-V-36 and 37 on an ESAS, but it does not include the AC power dependences for the "close" action. However, the logic related to opening the minimum flow valves does include the power dependences, which can result in the generation of cutsets that include the failure to open a flow path that was never isolated. If the appropriate power dependencies were accounted for in the isolation logic, the only events that could cause the MU-V-36 or MU-V-37 valves to be "stranded closed" are those in which an ESAS occurs when both divisions of power are available and then division "A" power fails before MU-V-36 can be opened.	Level 1 TMI-1 Importance List	Screened from analysis based on PRA insights as described in Section E.6.4.
5	Enhance Valves MU-V-76A/B and MU-V-77A/B to Allow for Rapid Alignment Changes in Accident Conditions	The current MU-V-76A/B and MU-V-77A/B valve configurations do not allow for rapid re-alignment during accident conditions. For TMI-1, the capability to quickly align the "C" HPI pump for seal injection would reduce the risk of prominent accident sequences in which thermal barrier cooling has failed in conjunction with the "A" and "B" HPI pumps. Replacing MU-V-76A/B and MU-V-77A/B with MOVs operable from the main control room would allow TMI-1 to use the "C" HPI pump for seal injection and prevent seal LOCAs when the normal cooling methods are unavailable.	Level 1 TMI-1 Importance List	This SAMA's net value is negative and is classified as "not cost beneficial".

TABLE E.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	BASELINE PHASE II DISPOSITION
6	Add Cross-ties Within the Trains of the Cooling Systems -DHR -DHRW -DHCCW	Some failure combinations that eliminate both trains of the DHR related cooling systems could be mitigated if cross-ties were available between trains of the DHR, DHRW, and DHCCW systems (not between the systems). For example, these cross-ties would be helpful in conditions where the flow path fails in one train while a pump failure or maintenance event disables the opposite train. To ensure the DHR cross-ties can be implemented in a timely manner for LPI requirements, the associated valves should be operable from the main control room.	Level 1 TMI-1 Importance List	This SAMA's net value is negative and is classified as "not cost beneficial".
7	Use Fire Service Water as an Alternate Cooling Source for the ICCW Heat Exchangers	For cases in which NSRW is unavailable due to hardware failures (e.g., flow diversion), the Fire Service Water system could be used to directly cool the ICCW heat exchangers for thermal barrier cooling support. Given that the ICCW pumps would be available for the relevant cases, a local, manual valve could be used for the alignment as time should be available for such an action.	Level 1 TMI-1 Importance List	This SAMA's net value is negative and is classified as "not cost beneficial".
8	Automate Reactor Coolant Pump Trip	Seal LOCAs resulting from operator failures to trip the RCPs on loss of motor bearing cooling could be reduced if high temperature sensors were installed on motor bearing cooling water lines to provide automatic trip signals.	Level 1 TMI-1 Importance List	This SAMA's net value is positive and is classified as "cost beneficial".
9	Proceduralize Local ADV Operation	TMI-1 has procedures to perform the local ADV operations that are not credited in the PRA model (the failure probability is set to 1.0). If the available procedures are credited, the RRW value of the operator action would be reduced below the SAMA review threshold. This SAMA is used demonstrate the reduction in the RRW that would occur when a reasonable failure probability is applied to the operator action.	Level 1 TMI-1 Importance List	Screened from analysis based on PRA insights as described in Section E.6.9.

TABLE E.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	BASELINE PHASE II DISPOSITION
10	Automate BWST Refill	Failure to refill the BWST is a large contributor to some SGTR sequences, especially those in which the MS ADVs fail to operate. Automating the refill function would improve the reliability of this process and reduce the contributions from prominent SGTR sequences by providing a long term high pressure injection source. This SAMA requires a new pump with a flow rate of at least 400 gpm with a connection to a borated water source that will provide suction for 24 hours. In addition, the pump should be able to supply water from a non-borated water source for an indefinite periods of time after depletion of the borated water source.	Level 1 TMI-1 Importance List	This SAMA's net value is negative and is classified as "not cost beneficial".
11	Enhance Extreme External Flooding Mitigation Equipment to Address SBO and Loss of Seal Cooling Scenarios	Making the extreme flooding equipment useful for SBO conditions, especially those with TD EFW failure, would require permanently mounting the submersible pumps so that the suctions could easily be swapped from a piped water source to the flood water source. Permanently installing the portable generator and the pumps so that they could be aligned from the MCR would improve alignment capabilities and address non-SBO loss of seal cooling cases through the ability to rapidly align alternate seal cooling.	Level 1 TMI-1 Importance List	This SAMA's net value is positive and is classified as "cost beneficial".
12	Use the DHR System as an Alternate Suction Source for HPI	Failures of the BWST suction path to the HPI pumps will lead to core damage in scenarios requiring early makeup. Through implementation of procedure changes, the DHR system could be aligned to take suction from the BWST and supply flow to the HPI system to allow injection in these cases.	Level 1 TMI-1 Importance List	This SAMA's net value is positive and is classified as "cost beneficial".

TABLE E.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	BASELINE PHASE II DISPOSITION
13	Change IA System Logic to Automatically Start IA-P-1A/B After a Low Voltage Trip in Conjunction with an ESAS	The current IA system logic requires the operators to re-load the IA compressors on emergency power after a low voltage trip when an ESAS is registered. Automating the re-loading of these compressors would remove the requirement for the operators to perform this task in accident conditions.	Level 1 TMI-1 Importance List	This SAMA's net value is negative and is classified as "not cost beneficial".
14	Replace HPI Pump Cooling Alignment Valves with MOVs	In the event that the normally aligned cooling source to a HPI pump fails, the current plant configuration requires local operation of the valves to swap the pump to the alternate cooling source. The time required to perform this action is considered to preclude it as a means of both preventing seal LOCAs in loss of seal cooling evolutions and for providing high pressure makeup. Replacing the valves with MOVs would allow the operators to rapidly align the alternate cooling source from the MCR in time to prevent a seal LOCA or provide high pressure injection.	Level 1 TMI-1 Importance List	This SAMA's net value is negative and is classified as "not cost beneficial".
15	Automate Swap to Recirculation Mode	The operator action to swap to recirculation mode is a key action for LOCA scenarios. Automating this function would improve the reliability of this action, especially in the rapidly evolving events where other actions are competing for the attention of the operators.	Level 1 TMI-1 Importance List	This SAMA's net value is negative and is classified as "not cost beneficial".
16	Automate HPI Injection on Low Pressurizer Level	Providing an automatic signal to initiate HPI on low pressurizer level would improve the reliability of HPI initiation.	Level 1 TMI-1 Importance List	This SAMA's net value is positive and is classified as "cost beneficial".
17	Auto Isolate Steam Generators on High Steam Line Flow	For steam line breaks downstream of the MSIVs, failure to isolate the relevant steam generator is an important contributor to core damage. The addition of logic to isolate the steam generator on high steam line flow would reduce the core damage contribution from isolation failures.	Level 1 TMI-1 Importance List	This SAMA's net value is negative and is classified as "not cost beneficial".

TABLE E.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	BASELINE PHASE II DISPOSITION
18	Provide the Capability to Align the Standby Battery Charger and the 1A/1B Cross-tie from the MCR	TMI has a spare 125V DC battery charger for each division that can be aligned to either battery bank within a division in the event that a normally operating battery charger fails. Currently, the alignment requires local actions. There is typically adequate time to align the charger in the event of a failure, but additional changes could be made to allow rapid alignment of the spare charger from the MCR to reduce the manipulation time and improve the man-machine interface.	Level 1 TMI-1 Importance List	This SAMA's net value is negative and is classified as "not cost beneficial".
19	Install Battery Backed Hydrogen Igniters or a Passive Hydrogen Ignition System	The addition of igniters would provide a means of preventing catastrophic combustible gas burns by continuously burning these gases before they reach critical levels. Providing battery backup power would increase the likelihood that this system would be available in LOOP events. Use of a passive system would also function in LOOP as well as long term SBO scenarios.	Level 2 TMI-1 Importance List	This SAMA's net value is positive and is classified as "cost beneficial".
20	Extend the High Pressure Boundary Through DHR Valve DH-V-3 for ISLOCA Isolation	The highest frequency ISLOCA scenario for TMI-1 is through two valves in the DHR suction line. While the scenario's CDF is low, the release frequency is relatively high given that primary containment is bypassed by definition. No effective mitigating actions are considered to be available in these cases because 1) the break may occur upstream of DH-V-3 or additional breaks in the low pressure boundary may occur after closure of a low pressure isolation valve, 2) reduction of primary system pressure may reduce the flow out of the break, but it would not stop it, and 3) refill of the BWST does not place the plant in a stable state and results in auxiliary building flooding. Extending the pressure boundary through DH-V-3 would provide an additional isolation point in these cases.	Level 2 TMI-1 Importance List	This SAMA's net value is negative and is classified as "not cost beneficial".

TABLE E.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	BASELINE PHASE II DISPOSITION
21	Install Concrete Shields to Block Direct Pathways from the RPV to the Containment Wall and/or Direct Containment Flooding Early in External Flooding Scenarios	This SAMA is based on a failure mode identified in the Level 2 analysis that indicates corium ejection during RV failure could result in dispersal of debris such that it could directly interact with the containment wall and cause a failure of the wall. For some external flooding scenarios, it may be possible to change the procedures to direct containment flooding early such that water would be available on the containment floor before loss of power.	Level 2 TMI-1 Importance List	This SAMA's net value is negative and is classified as "not cost beneficial".
22	Install an Independent AFW System	For TMI-1, loss of MFW after a trip coupled with loss of EFW can lead to large radionuclide releases in SGTR and induced SGTR scenarios due to the unavailability of water in the SGs for fission product scrubbing. A large contributor to EFW failure is estimated to be system wide common cause failures. An independent, motor driven, auxiliary feedwater system would be an effective means of addressing these cases. Power dependence is not a large issue for the cases addressed by this SAMA and the independent EFW pump is assumed to be powered by existing emergency power such that it would not be capable of mitigating SBO scenarios.	Level 2 TMI-1 Importance List	This SAMA's net value is negative and is classified as "not cost beneficial".
23	Develop Alarm Response Procedures to Direct Operation of RR-V-5 on Low RBEC Flow	Failure of RR-V-6 to open results in the loss of RBEC flow to the reactor building coolers, which can be diagnosed using the system flow indicators in the main control room; however, no alarm response procedures exist to specifically direct operation of the bypass valve (RR-V-5). If this procedure was developed, it may reduce the diagnosis time and improve the reliability of this operator action in an accident conditions.	Level 2 TMI-1 Importance List	This SAMA's net value is negative and is classified as "not cost beneficial".

TABLE E.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	BASELINE PHASE II DISPOSITION
24	Install Damage Resistant, High Temperature RCP Seals with a Diesel Engine as an Alternate Drive for an EFW Pump and a Portable Generator for Level Control Instrumentation	For SBOs in which EFW has failed, neither primary nor secondary side cooling is available. Installing the enhanced RCP seals will prevent seal LOCAs and use of a portable generator would allow the turbine driven EFW pump to be used for extended periods in an SBO, as suggested in SAMA 2. However, in the event that the turbine driven EFW pump fails, there would be no means of providing secondary side makeup. Turbine driven EFW failures could be mitigated if an engine was available to drive one of the EFW pumps. Other industry SAMA applications have suggested similar strategies, but they typically suggest the turbine driven pumps as the best option for connection to the engine based on ease of connection. For scenarios with turbine driven EFW failure, however, the initial TD EFW pump failure may prevent its further use even with an alternate motive source. As a result, this SAMA, in addition to the requirements of SAMA 2, requires that the diesel engine be connected to one of the motor driven EFW pumps.	Palisades SAMA Analysis (NMC 2005)	This SAMA's net value is negative and is classified as "not cost beneficial".
25	Install an Additional EDG	An additional source of AC power is a potential means of supplying an entire division of safety equipment in the event that on-site AC power is lost in a LOOP. While additional EDGs are expensive, they can be cost effective at some plants, especially those with a large LOOP/SBO contribution to CDF.	Palisades SAMA Analysis (NMC 2005)	This SAMA's net value is negative and is classified as "not cost beneficial".

TABLE E.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	BASELINE PHASE II DISPOSITION
26	Reroute Cables so that They Do Not Pass Over Ignition Sources in Fire Area CB-FA-2e (West Inverter Room) or Wrap them in Fire Proof Material	Some of the risk from fires in this room is from damage to cables that run over ignition sources. If the cable trays were re-routed away from the electrical equipment that they currently pass over, the consequences of equipment fires in the inverter room could be reduced.	TMI-1 IPEEE (Fire)	This SAMA's net value is negative and is classified as "not cost beneficial".
27	Improve the 480V AC load center welds	The IPEEE determined that the existing 480V AC load centers were among the weaker components in the TMI-1 AC distribution system. Adding reinforcements to the welds on the load center framework would improve the seismic durability of the structure and increase the likelihood that the system would be available after a seismic event. The other low seismic capacity components, the EDG air receivers, were enhanced subsequent to the completion of the IPEEE.	TMI-1 IPEEE (Seismic)	This SAMA's net value is positive and is classified as "cost beneficial".
28	Improve the Decay Heat Service Cooler (DC-C-2A/B) Anchorages	The IPEEE determined that the existing Decay Heat Service Coolers (DC-C-2A/B) lacked sufficiently durable anchorages. Replacing the anchorages with more robust anchorages would improve the seismic durability of the structure and increase the likelihood that the heat exchangers would be available after a seismic event.	TMI-1 IPEEE (Seismic)	This SAMA's net value is negative and is classified as "not cost beneficial".

TABLE E.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	BASELINE PHASE II DISPOSITION
29	Replace EDG Ground Resistors	Failure of the EDG ground resistors results in failure of the EDGs, which will lead to core damage in the event that off-site power is not available. Given that the HCLPF capacity for these components was estimated at 0.25g compared with 0.09g capacities of off-site power components (such as the 1/A and 1/B distribution buses or the aux transformers), it is likely that core damage will ensue due to long term loss of power if the EDG ground resistors fail from seismic shock. Replacing the resistors with more durable versions would improve the reliability of the EDGs in seismic events.	TMI-1 IPEEE (Seismic)	This SAMA's net value is negative and is classified as "not cost beneficial".
30	Improve Diesel Fire Pump Fuel Oil Tank and Battery Rack Supports	The Fire Service Water system provides cooling to the SBO EDG, backup cooling the DHCCW heat exchangers, and backup cooling to the "1A" and "1B" Instrument Air compressors. While seismic failures to the systems FSW supports would likely limit the benefit of improving the fuel oil tank and battery racks, some benefit may be available through improvements to the diesel fire pump's reliability.	TMI-1 IPEEE (Fire/Seismic)	This SAMA's net value is negative and is classified as "not cost beneficial".
31	Modify Specific Containment Penetration MOVs to "Fail Closed"	Most containment penetrations have AOV or SOV isolation valves that will fail closed on loss of air or power; however, there are cases in which MOVs are used instead. Those lines that do not include a pair of AOVs or SOVs that fail closed are typically below 1" in diameter or include at least one AOV or SOV that will fail closed on loss of air or power. However, the NSCCW and RBEC systems include penetrations that only include MOVs. While these are closed cooling systems that would not normally provide a credible release path, heat exchanger breaks in seismic events could provide containment bypass routes in the event that a failure also occurs in the reactor building. Changing one of the valves in each of these paths to fail closed is a means of increasing the isolation probability over what is available from manual action.	TMI-1 IPEEE (Seismic)	Screened from analysis based on PRA insights as described in Section E.6.31.

TABLE E.5-4
PHASE II SAMA

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	BASELINE PHASE II DISPOSITION
32	Pre-stage Severe Flooding Equipment	Pre-staging the equipment used to prevent core damage in severe flooding conditions would reduce sources of error in the alignment actions and reduce the time required to perform the task. Potential changes include: - Storing the portable EDG on the turbine deck - Adding a normally empty fuel oil tank for the portable EDG to the turbine deck - Permanently running power cable from the portable EDG to the pump areas A potential permutation of this SAMA would be to procure an additional portable EDG to reduce the failure contribution from the power source.	TMI-1 IPEEE (External Flooding)	This SAMA's net value is positive and is classified as "cost beneficial".
33	Increase the Flood Protection Height	The current configuration protects to the design basis limit of 310 feet msl and levels any higher result in topping of the existing flood doors and flooding of sensitive areas. Raising the height of the flood doors (or completely sealing the doors) would prevent water incursion and allow for continued operation of the normal safety equipment.	TMI-1 IPEEE (External Flooding)	This SAMA's net value is positive and is classified as "cost beneficial".

TABLE E.8-1
SUMMAY OF COST BENEFICIAL SAMAS

SAMA ID	SAMA Title	SAMA Implementation Cost	Averted Cost-Risk	Net Value	DPD Ratio*	Comments
SAMA 8	Automate Reactor Coolant Pump Trip	$145,000	$3,395,359	$3,250,359	23.4	This SAMA would complement the set of existing RCP protection signals to protect against potential cooling failures that appear to be critical to the RCPs. Given the relatively low implementation cost and the relatively large risk reduction associated with the change, this SAMA is a candidate for implementation.
SAMA 32	Pre-stage Severe Flooding Equipment	$1,700,000	$35,893,061	$34,193,061	21.1	This SAMA yields a large averted cost-risk for TMI-1. There is a large degree of uncertainty associated with flood risk that could impact the results of the cost benefit analysis, but the location of the plant suggests that enhancements to the extreme flood mitigation strategy should be in place for the site. This SAMA should be considered for implementation.
SAMA 19	Install Battery Backed Hydrogen Igniters or a Passive Hydrogen Ignition System	$760,000	$8,601,659	$7,841,659	11.3	The passive hydrogen ignition system is designed to prevent containment failures due to post-core-damage combustible gas burns in accident conditions and is intended to be operable even in long term SBO evolutions. The current PRA model considers combustible gas burns to be a credible containment failure mode, but the conservative assumptions related to the containment failure probabilities are considered to greatly overestimate the benefit of this SAMA. This SAMA is not recommended for implementation.
SAMA 12	Use the DHR System as an Alternate Suction Source for HPI	$50,000	$545,705	$495,705	10.9	This is an inexpensive change that would allow the operators to use HPI in the event that the normal BWST suction path fails. While the probability that the alternate suction alignment would be required during the life of the plant is low, this SAMA would proceduralize a means of addressing failures that could otherwise contribute to core damage. This SAMA should be considered for implementation.

TABLE E.8-1
SUMMAY OF COST BENEFICIAL SAMAS

SAMA ID	SAMA Title	SAMA Implementation Cost	Averted Cost-Risk	Net Value	DPD Ratio*	Comments
SAMA 11	Enhance Extreme External Flooding Mitigation Equipment to Address SBO and Loss of Seal Cooling Scenarios	$4,250,000	$44,243,903	$39,993,903	10.4	SAMA 11 is a complex plant modification that was designed to reduce internal events SBO risk by taking advantage of equipment that could also be used to mitigate the extreme flood scenarios. The intent of the SAMA was to determine if changes could be made to the extreme flooding equipment such that it would be beneficial in non-external flooding SBO cases. However, the differences in the external flooding SBO and a standard SBO require significantly different capabilities. The main issue is that the external flooding strategy uses the flood cues to predict the need for the mitigation equipment well before the loss of AC power. The implication is that seal cooling can be maintained such that there will not be a seal LOCA.
SAMA 11 (cont.)						If a seal LOCA did occur, the primary side makeup requirements increase and the injection inventory may be depleted over the long potential mission times for external flooding events. Consequently, seal LOCA prevention is considered to be a requirement for long term success. For standard SBO cases, seal LOCAs are assumed to be preventable only if seal cooling can be restored within 13 minutes of the initial loss of cooling (standard SBOs are generally not anticipated and the mitigation equipment could not be pre-initiated). Seal LOCA prevention would require an auto start/load of the 480V AC generator on an undervoltage signal to the HPI pump buses or high RCP cooling water temperature signal. Even without external flooding contributions, this SAMA would be cost beneficial based on the 95th percentile PRA results. However, SAMA 2 may be a more desirable means of addressing seal LOCAs given that its passive design would likely be more reliable than an active cooling system and because it yields a larger internal events risk reduction, which has benefits outside of the SAMA analysis.

TABLE E.8-1
SUMMAY OF COST BENEFICIAL SAMAS

SAMA ID	SAMA Title	SAMA Implementation Cost	Averted Cost-Risk	Net Value	DPD Ratio*	Comments
SAMA 33	Increase the Flood Protection Height	$2,700,000	$25,141,284	$22,441,284	9.3	This SAMA is a potential means of mitigating severe flood risk; however, this strategy is predicated on identifying and eliminating all flow paths into areas containing safety equipment. In addition, there is the implicit assumption that the flood gates and buildings will withstand the hydrodynamic forces of the flood waters. Because of the uncertainty associated with this SAMA, SAMA 32 is considered to be the better approach to addressing flood risk and SAMA 33 a less desirable alternative. If SAMA 32 is implemented, SAMA 33 would not be cost beneficial.
SAMA 27	Improve the 480V AC load center welds	$575,000	$3,593,752	$3,018,752	6.3	This modification was identified in the IPEEE as a change that could reduce seismic risk by about 50 percent. While this enhancement addressed a significant seismic concern, the modifications were not implemented because the load center failures only accounted for about 10 percent of the total TMI-1 CDF (internal + external events). If the LLNL seismic hazard curves are used in place of the EPRI seismic hazard curves that were used in the IPEEE base case, the seismic CDF increases from 3.21E-05/yr to 8.43E-05/yr. Given this condition, strengthening the 480 V AC load center welds would yield a CDF reduction of 4.22E-05/yr. While this appears to be a likely candidate for implementation, the seismic hazard curves represent a source of uncertainty in the seismic risk evaluation. Because TMI-1 is located in a seismically stable region, this SAMA may warrant further review, but it is not suggested for implementation at this time.

TABLE E.8-1
SUMMAY OF COST BENEFICIAL SAMAS

SAMA ID	SAMA Title	SAMA Implementation Cost	Averted Cost-Risk	Net Value	DPD Ratio*	Comments
SAMA 16	Automate HPI Injection on Low Pressurizer Level	$1,100,000	$4,379,735	$3,279,735	4.0	This SAMA suggests further automating an action on which the operators are well trained. While operator training is thorough and manual initiation failures are very unlikely even in cases where the current initiation logic would not actuate, failure to manually initiate HPI implies that a severe diagnosis error has occurred and that subsequent actions are also in jeopardy of failing. Even though the automatic HPI initiation could be inhibited/cancelled, such an action would require an active assessment of the RCS level and it would provide an opportunity for level recovery. However, the benefit of this SAMA is based on the PRA human error probability assessments, which are typically associated with a relatively high degree of uncertainty. In this case, a single joint human error probability is responsible for most of the PRA model-predicted risk and it is not appropriate to justify a large expenditure of resources to address a risk area with such a wide uncertainty. This SAMA should not be considered as a high priority item.
SAMA 21	Install Concrete Shields to Block Direct Pathways from the RPV to the Containment Wall and/or Direct Containment Flooding Early in External Flooding Scenarios	$1,200,000	$3,248,127	$2,048,127	2.7	This SAMA yields a relatively low benefit for internal events even for the 95th percentile results (about $560k), but when the benefits associated with the external flood contributions are added, the SAMA shows a much higher benefit. Implementation of SAMA 32 would reduce the benefit associated with this SAMA to the point where it would no longer be cost beneficial. If SAMA 32 is implemented, SAMA 21 should not be considered for implementation. Even without implementation of SAMA 32, discussions with Severe Accident Management personnel indicate that the path from the reactor vessel to the containment shell is obstructed and that the shell liner failure probability used in the PRA may be pessimistic.
SAMA 23	Develop Alarm Response Procedures to Direct Operation of RR-V-5 on Low RBEC Flow	$50,000	$84,230	$34,230	1.7	SAMA 23 is a low cost procedure change that would help the operators diagnose containment cooling problems. This SAMA should be considered for implementation.

TABLE E.8-1
SUMMAY OF COST BENEFICIAL SAMAS

SAMA ID	SAMA Title	SAMA Implementation Cost	Averted Cost-Risk	Net Value	DPD Ratio*	Comments
SAMA 2	Install Damage Resistant, High Temperature RCP Seals with a Portable 480V Generator for Extended EFW Operation	$7,300,000	$11,816,753	$4,516,753	1.6	SAMA 2 is a high cost change that impacts seal LOCAs and SBO scenarios. When the 95th percentile PRA results are considered, this SAMA is shown to be potentially cost beneficial. While the DPD ratio is smaller than what has been estimated for SAMA 11, SAMA 2 may be a more desirable means of addressing seal LOCAs given that its passive design would likely be more reliable than an active cooling system and because it yields a larger internal events risk reduction, which has benefits outside of the SAMA analysis.
SAMA 24	Install Damage Resistant, High Temperature RCP Seals with a Diesel Engine as an Alternate Drive for an EFW Pump and a Portable Generator for Level Control Instrumentation	$8,400,000	$12,144,553	$3,744,553	1.4	SAMA 24 is an enhancement of SAMA 2 that is designed to address turbine driven EFW failures. Given that the difference in benefit between SAMA 2 and SAMA 24 when considering the 95th percentile PRA results is only $327,800, it would not be beneficial to add the diesel driven motor option for the EFW pump when the cost of that portion of the SAMA is estimated to be $1.1 million. This SAMA is not recommended for implementation.
SAMA 7	Use Fire Service Water as an Alternate Cooling Source for the ICCW Heat Exchangers	$1,000,000	$1,235,449	$235,449	1.2	SAMA 7 provides an alternate means of cooling the ICCW heat exchangers when normal cooling flow to the heat exchangers fails. While this enhancement provides a non-negligible reduction in risk, the margin by which it is cost beneficial is low and it is not a likely candidate for implementation.
SAMA 15	Automate Swap to Recirculation Mode	$450,000	$547,520	$97,520	1.2	SAMA 15 is a SAMA that has been identified for many plants in the industry. For TMI-1, it is only considered to be cost effective using the 95th percentile PRA results and a generic implementation cost of $450,000, which may be low. This is not a high priority candidate for implementation based on the small margin by which it is cost effective and because a plant specific implementation cost estimate may provide a basis for excluding it from consideration.

TABLE E.8-1
SUMMAY OF COST BENEFICIAL SAMAS

SAMA ID	SAMA Title	SAMA Implementation Cost	Averted Cost-Risk	Net Value	DPD Ratio*	Comments
SAMA 26	Reroute Cables so that They Do Not Pass Over Ignition Sources in Fire Area CB-FA-2e (West Inverter Room) or Wrap them in Fire Proof Material	$900,000	$1,016,573	$116,573	1.1	The margin by which this SAMA is cost beneficial is small and the methods available to estimate the averted cost-risk were limited, as described in Section E.5.1.6.1. This SAMA may be considered cost beneficial, but a more detailed, up to date assessment of the fire risk would be required to better define the potential benefit of protecting the cables in Fire Area CB-FA-2E.

Table Notes:

* The DPD (dollar per dollar) Ratio is the Averted Cost-Risk divided by the SAMA cost.

** The absolute change in CDF (baseline CDF minus estimated CDF with the particular SAMA in place) is presented followed by the percent change (in parentheses).

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ADDENDUM 1 TO ATTACHMENT E
SELECTED PREVIOUS INDUSTRY SAMAS

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
Improvements Related to RCP Seal LOCAs (Loss of CC or SW)		
1	Cap downstream piping of normally closed component cooling water drain and vent valves.	SAMA would reduce the frequency of a loss of component cooling event, a large portion of which was derived from catastrophic failure of one of the many single isolation valves.
2	Enhance loss of component cooling procedure to facilitate stopping reactor coolant pumps.	SAMA would reduce the potential for reactor coolant pump (RCP) seal damage due to pump bearing failure.
3	Enhance loss of component cooling procedure to present desirability of cooling down reactor coolant system (RCS) prior to seal LOCA.	SAMA would reduce the potential for RCP seal failure.
4	Provide additional training on the loss of component cooling.	SAMA would potentially improve the success rate of operator actions after a loss of component cooling (to restore RCP seal damage).
5	Provide hardware connections to allow another essential raw cooling water system to cool charging pump seals.	SAMA would reduce effect of loss of component cooling by providing a means to maintain the centrifugal charging pump seal injection after a loss of component cooling.
6	Procedure changes to allow cross connection of motor cooling for residual heat removal service water (RHRSW) pumps.	SAMA would allow continued operation of both RHRSW pumps on a failure of one train of PSW.
7	Proceduralize shedding component cooling water loads to extend component cooling heatup on loss of essential raw cooling water.	SAMA would increase time before the loss of component cooling (and reactor coolant pump seal failure) in the loss of essential raw cooling water sequences.
8	Increase charging pump lube oil capacity.	SAMA would lengthen the time before centrifugal charging pump failure due to lube oil overheating in loss of CC sequences.
9	Eliminate the RCP thermal barrier dependence on component cooling such that loss of component cooling does not result directly in core damage.	SAMA would prevent the loss of recirculation pump seal integrity after a loss of component cooling. Watts Bar Nuclear Plant IPE said that they could do this with essential raw cooling water connection to RCP seals.
10	Add redundant DC control power for PSW pumps C & D.	SAMA would increase reliability of PSW and decrease CDF due to a loss of SW.
11	Create an independent RCP seal injection system, with a dedicated diesel.	SAMA would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of component cooling or SW or from a SBO event.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
12	Use existing hydro-test pump for RCP seal injection.	SAMA would provide an independent seal injection source, without the cost of a new system.
13	Replace ECCS pump motor with air-cooled motors.	SAMA would eliminate ECCS dependency on component cooling system (but not on room cooling).
14	Install improved RCS pumps seals.	SAMA would reduce probability of RCP seal LOCA by installing RCP seal O-ring constructed of improved materials
15	Install additional component cooling water pump.	SAMA would reduce probability of loss of component cooling leading to RCP seal LOCA.
16	Prevent centrifugal charging pump flow diversion from the relief valves.	SAMA modification would reduce the frequency of the loss of RCP seal cooling if relief valve opening causes a flow diversion large enough to prevent RCP seal injection.
17	Change procedures to isolate RCP seal letdown flow on loss of component cooling, and guidance on loss of injection during seal LOCA.	SAMA would reduce CDF from loss of seal cooling.
18	Implement procedures to stagger high-pressure safety injection (HPSI) pump use after a loss of SW.	SAMA would allow HPSI to be extended after a loss of SW.
19	Use FPS pumps as a backup seal injection and high-pressure makeup.	SAMA would reduce the frequency of the RCP seal LOCA and the SBO CDF.
20	Enhance procedural guidance for use of cross-tied component cooling or SW pumps.	SAMA would reduce the frequency of the loss of component cooling water and SW.
21	Procedure enhancements and operator training in support system failure sequences, with emphasis on anticipating problems and coping.	SAMA would potentially improve the success rate of operator actions subsequent to support system failures.
22	Improved ability to cool the residual heat removal (RHR) heat exchangers.	SAMA would reduce the probability of a loss of decay heat removal by implementing procedure and hardware modifications to allow manual alignment of the FPS or by installing a component cooling water cross-tie.
23	Additional SW Pump	SAMA would conceivably reduce common cause dependencies from SW system and thus reduce plant risk through system reliability improvement.
24	Create an independent RCP seal injection system, without dedicated diesel	This SAMA would add redundancy to RCP seal cooling alternatives, reducing the CDF from loss of CC or SW, but not SBO.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
Improvements Related to Heating, Ventilation, and Air Conditioning		
25	Provide reliable power to control building fans.	SAMA would increase availability of CR ventilation on a loss of power.
26	Provide a redundant train of ventilation.	SAMA would increase the availability of components dependent on room cooling.
27	Procedures for actions on loss of HVAC.	SAMA would provide for improved credit to be taken for loss of HVAC sequences (improved affected electrical equipment reliability upon a loss of control building HVAC).
28	Add a diesel building switchgear room high temperature alarm.	SAMA would improve diagnosis of a loss of switchgear room HVAC. Option 1: Install high temp alarm. Option 2: Redundant louver and thermostat
29	Create ability to switch fan power supply to DC in an SBO event.	SAMA would allow continued operation in an SBO event. This SAMA was created for reactor core isolation cooling (RCIC) system room at Fitzpatrick Nuclear Power Plant.
30	Enhance procedure to instruct operators to trip unneeded RHR/CS pumps on loss of room ventilation.	SAMA increases availability of required RHR/CS pumps. Reduction in room heat load allows continued operation of required RHR/CS pumps, when room cooling is lost.
31	Stage backup fans in switchgear (SWGR) rooms	This SAMA would provide alternate ventilation in the event of a loss of SWGR Room ventilation
Improvements Related to Ex-Vessel Accident Mitigation/Containment Phenomena		
32	Delay containment spray actuation after large LOCA.	SAMA would lengthen time of refueling water storage tank (RWST) availability.
33	Install containment spray pump header automatic throttle valves.	SAMA would extend the time over which water remains in the RWST, when full CS flow is not needed
34	Install an independent method of suppression pool cooling.	SAMA would decrease the probability of loss of containment heat removal. For PWRs, a potential similar enhancement would be to install an independent cooling system for sump water.
35	Develop an enhanced drywell spray system.	SAMA would provide a redundant source of water to the containment to control containment pressure, when used in conjunction with containment heat removal.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
36	Provide dedicated existing drywell spray system.	SAMA would provide a source of water to the containment to control containment pressure, when used in conjunction with containment heat removal. This would use an existing spray loop instead of developing a new spray system.
37	Install an unfiltered hardened containment vent.	SAMA would provide an alternate decay heat removal method for non-ATWS events, with the released fission products not being scrubbed.
38	Install a filtered containment vent to remove decay heat.	SAMA would provide an alternate decay heat removal method for non-ATWS events, with the released fission products being scrubbed. Option 1: Gravel Bed Filter Option 2: Multiple Venturi Scrubber
39	Install a containment vent large enough to remove ATWS decay heat.	Assuming that injection is available, this SAMA would provide alternate decay heat removal in an ATWS event.
40	Create/enhance hydrogen recombiners with independent power supply.	SAMA would reduce hydrogen detonation at lower cost, Use either 1) a new independent power supply 2) a nonsafety-grade portable generator 3) existing station batteries 4) existing AC/DC independent power supplies.
41	Install hydrogen recombiners.	SAMA would provide a means to reduce the chance of hydrogen detonation.
42	Create a passive design hydrogen ignition system.	SAMA would reduce hydrogen denotation system without requiring electric power.
43	Create a large concrete crucible with heat removal potential under the basemat to contain molten core debris.	SAMA would ensure that molten core debris escaping from the vessel would be contained within the crucible. The water cooling mechanism would cool the molten core, preventing a melt-through of the basemat.
44	Create a water-cooled rubble bed on the pedestal.	SAMA would contain molten core debris dropping on to the pedestal and would allow the debris to be cooled.
45	Provide modification for flooding the drywell head.	SAMA would help mitigate accidents that result in the leakage through the drywell head seal.
46	Enhance FPS and/or standby gas treatment system hardware and procedures.	SAMA would improve fission product scrubbing in severe accidents.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
47	Create a reactor CFS.	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.
48	Create other options for reactor cavity flooding.	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.
49	Enhance air return fans (ice condenser plants).	SAMA would provide an independent power supply for the air return fans, reducing containment failure in SBO sequences.
50	Create a core melt source reduction system.	SAMA would provide cooling and containment of molten core debris. Refractory material would be placed underneath the reactor vessel such that a molten core falling on the material would melt and combine with the material. Subsequent spreading and heat removal form the vitrified compound would be facilitated, and concrete attack would not occur
51	Provide a containment inerting capability.	SAMA would prevent combustion of hydrogen and carbon monoxide gases.
52	Use the FPS as a backup source for the containment spray system.	SAMA would provide redundant containment spray function without the cost of installing a new system.
53	Install a secondary containment filtered vent.	SAMA would filter fission products released from primary containment.
54	Install a passive containment spray system.	SAMA would provide redundant containment spray method without high cost.
55	Strengthen primary/secondary containment.	SAMA would reduce the probability of containment overpressurization to failure.
56	Increase the depth of the concrete basemat or use an alternative concrete material to ensure melt-through does not occur.	SAMA would prevent basemat melt-through.
57	Provide a reactor vessel exterior cooling system.	SAMA would provide the potential to cool a molten core before it causes vessel failure, if the lower head could be submerged in water.
58	Construct a building to be connected to primary/secondary containment that is maintained at a vacuum.	SAMA would provide a method to depressurize containment and reduce fission product release.
59	Refill CST	SAMA would reduce the risk of core damage during events such as extended SBOs or LOCAs which render the suppression pool unavailable as an injection source due to heat up.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
60	Maintain ECCS suction on CST	SAMA would maintain suction on the CST as long as possible to avoid pump failure as a result of high suppression pool temperature
61	Modify containment flooding procedure to restrict flooding to below TAF	SAMA would avoid forcing containment venting
62	Enhance containment venting procedures with respect to timing, path selection and technique.	SAMA would improve likelihood of successful venting strategies.
63	Severe Accident EPGs/AMGs	SAMA would lead to improved arrest of core melt progress and prevention of containment failure
64	Simulator Training for Severe Accident	SAMA would lead to improved arrest of core melt progress and prevention of containment failure
65	Dedicated Suppression Pool Cooling	SAMA would decrease the probability of loss of containment heat removal. While PWRs do not have suppression pools, a similar modification may be applied to the sump. Installation of a dedicated sump cooling system would provide an alternate method of cooling injection water.
66	Larger Volume Containment	SAMA increases time before containment failure and increases time for recovery
67	Increased Containment Pressure Capability (sufficient pressure to withstand severe accidents)	SAMA minimizes likelihood of large releases
68	Improved Vacuum Breakers (redundant valves in each line)	SAMA reduces the probability of a stuck open vacuum breaker.
69	Increased Temperature Margin for Seals	This SAMA would reduce containment failure due to drywell head seal failure caused by elevated temperature and pressure.
70	Improved Leak Detection	This SAMA would help prevent LOCA events by identifying pipes which have begun to leak. These pipes can be replaced before they break.
71	Suppression Pool Scrubbing	Directing releases through the suppression pool will reduce the radionuclides allowed to escape to the environment.
72	Improved Bottom Penetration Design	SAMA reduces failure likelihood of RPV bottom head penetrations
73	Larger Volume Suppression Pool (double effective liquid volume)	SAMA would increase the size of the suppression pool so that heatup rate is reduced, allowing more time for recovery of a heat removal system

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
74	Unfiltered Vent	SAMA would provide an alternate decay heat removal method with the released fission products not being scrubbed.
75	Filtered Vent	SAMA would provide an alternate decay heat removal method with the released fission products being scrubbed.
76	Post Accident Inerting System	SAMA would reduce likelihood of gas combustion inside containment
77	Hydrogen Control by Venting	Prevents hydrogen detonation by venting the containment before combustible levels are reached.
78	Pre-inerting	SAMA would reduce likelihood of gas combustion inside containment
79	Ignition Systems	Burning combustible gases before they reach a level which could cause a harmful detonation is a method of preventing containment failure.
80	Fire Suppression System Inerting	Use of the FPS as a back up containment inerting system would reduce the probability of combustible gas accumulation. This would reduce the containment failure probability for small containments (e.g. BWR MKI).
81	Drywell Head Flooding	SAMA would provide intentional flooding of the upper drywell head such that if high drywell temperatures occurred, the drywell head seal would not fail.
82	Containment Spray Augmentation	This SAMA would provide additional means of providing flow to the containment spray system.
83	Integral Basemat	This SAMA would improve containment and system survivability for seismic events.
84	Reactor Building Sprays	This SAMA provides the capability to use firewater sprays in the reactor building to mitigate release of fission products into the Rx Bldg following an accident.
85	Flooded Rubble Bed	SAMA would contain molten core debris dropping on to the pedestal and would allow the debris to be cooled.
86	Reactor Cavity Flooder	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.
87	Basaltic Cements	SAMA minimizes carbon dioxide production during core concrete interaction.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
88	Provide a core debris control system	(Intended for ice condenser plants): This SAMA would prevent the direct core debris attack of the primary containment steel shell by erecting a barrier between the seal table and the containment shell.
89	Add ribbing to the containment shell	This SAMA would reduce the risk of buckling of containment under reverse pressure loading.
Improvements Related to Enhanced AC/DC Reliability/Availability		
90	Proceduralize alignment of spare diesel to shutdown board after LOOP and failure of the diesel normally supplying it.	SAMA would reduce the SBO frequency.
91	Provide an additional DG.	SAMA would increase the reliability and availability of onsite emergency AC power sources.
92	Provide additional DC battery capacity.	SAMA would ensure longer battery capability during an SBO, reducing the frequency of long-term SBO sequences.
93	Use fuel cells instead of lead-acid batteries.	SAMA would extend DC power availability in an SBO.
94	Procedure to cross-tie high-pressure core spray diesel.	SAMA would improve core injection availability by providing a more reliable power supply for the high-pressure core spray pumps.
95	Improve 4.16-kV bus cross-tie ability.	SAMA would improve AC power reliability.
96	Incorporate an alternate battery charging capability.	SAMA would improve DC power reliability by either cross-tying the AC busses, or installing a portable diesel-driven battery charger.
97	Increase/improve DC bus load shedding.	SAMA would extend battery life in an SBO event.
98	Replace existing batteries with more reliable ones.	SAMA would improve DC power reliability and thus increase available SBO recovery time.
99	Mod for DC Bus A reliability.	SAMA would increase the reliability of AC power and injection capability. Loss of DC Bus A causes a loss of main condenser, prevents transfer from the main transformer to OSP, and defeats one half of the low vessel pressure permissive for low pressure coolant injection (LPCI)/CS injection valves.
100	Create AC power cross-tie capability with other unit.	SAMA would improve AC power reliability.
101	Create a cross-tie for diesel fuel oil.	SAMA would increase diesel fuel oil supply and thus DG, reliability.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
102	Develop procedures to repair or replace failed 4-kV breakers.	SAMA would offer a recovery path from a failure of the breakers that perform transfer of 4.16-kV non-emergency busses from unit station service transformers, leading to loss of emergency AC power.
103	Emphasize steps in recovery of OSP after an SBO.	SAMA would reduce HEP during OSP recovery.
104	Develop a severe weather conditions procedure.	For plants that do not already have one, this SAMA would reduce the CDF for external weather-related events.
105	Develop procedures for replenishing diesel fuel oil.	SAMA would allow for long-term diesel operation.
106	Install gas turbine generator.	SAMA would improve onsite AC power reliability by providing a redundant and diverse emergency power system.
107	Create a backup source for diesel cooling. (Not from existing system)	This SAMA would provide a redundant and diverse source of cooling for the DGs, which would contribute to enhanced diesel reliability.
108	Use FPS as a backup source for diesel cooling.	This SAMA would provide a redundant and diverse source of cooling for the DGs, which would contribute to enhanced diesel reliability.
109	Provide a connection to an alternate source of OSP.	SAMA would reduce the probability of a LOOP event.
110	Bury OSP lines.	SAMA could improve OSP reliability, particularly during severe weather.
111	Replace anchor bolts on DG oil cooler.	Millstone Nuclear Power Station found a high seismic SBO risk due to failure of the diesel oil cooler anchor bolts. For plants with a similar problem, this would reduce seismic risk. Note that these were Fairbanks Morse DGs.
112	Change undervoltage (UV), AFW actuation signal (AFAS) block and high pressurizer pressure actuation signals to 3-out-of-4, instead of 2-out-of-4 logic.	SAMA would reduce risk of 2/4 inverter failure.
113	Provide DC power to the 120/240-V vital AC system from the Class 1E station service battery system instead of its own battery.	SAMA would increase the reliability of the 120-VAC Bus.
114	Bypass DG Trips	SAMA would allow D/Gs to operate for longer.
115	2.i. 16 hour SBO Injection	SAMA includes improved capability to cope with longer SBO scenarios.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
116	Steam Driven Turbine Generator	This SAMA would provide a steam driven turbine generator which uses reactor steam and exhausts to the suppression pool. If large enough, it could provide power to additional equipment.
117	Alternate Pump Power Source	This SAMA would provide a small dedicated power source such as a dedicated diesel or gas turbine for the feedwater or condensate pumps, so that they do not rely on OSP.
118	Additional DG	SAMA would reduce the SBO frequency.
119	Increased Electrical Divisions	SAMA would provide increased reliability of AC power system to reduce core damage and release frequencies.
120	Improved Uninterruptible Power Supplies	SAMA would provide increased reliability of power supplies supporting front-line equipment, thus reducing core damage and release frequencies.
121	AC Bus Cross-Ties	SAMA would provide increased reliability of AC power system to reduce core damage and release frequencies.
122	Gas Turbine	SAMA would improve onsite AC power reliability by providing a redundant and diverse emergency power system.
123	Dedicated RHR (bunkered) Power Supply	SAMA would provide RHR with more reliable AC power.
124	Dedicated DC Power Supply	This SAMA addresses the use of a diverse DC power system such as an additional battery or fuel cell for the purpose of providing motive power to certain components (e.g., RCIC).
125	Additional Batteries/Divisions	This SAMA addresses the use of a diverse DC power system such as an additional battery or fuel cell for the purpose of providing motive power to certain components (e.g., RCIC).
126	Fuel Cells	SAMA would extend DC power availability in an SBO.
127	DC Cross-ties	This SAMA would improve DC power reliability.
128	Extended SBO Provisions	SAMA would provide reduction in SBO sequence frequencies.
129	Add an automatic bus transfer feature to allow the automatic transfer of the 120V vital AC bus from the on-line unit to the standby unit	Plants are typically sensitive to the loss of one or more 120V vital AC buses. Manual transfers to alternate power supplies could be enhanced to transfer automatically.
Improvements in Identifying and Mitigating Containment Bypass		

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
130	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture (SGTR).	SAMA would enhance depressurization during a SGTR.
131	Improve SGTR coping abilities.	SAMA would improve instrumentation to detect SGTR, or additional system to scrub fission product releases.
132	Add other SGTR coping abilities.	SAMA would decrease the consequences of an SGTR.
133	Increase secondary side pressure capacity such that an SGTR would not cause the relief valves to lift.	SAMA would eliminate direct release pathway for SGTR sequences.
134	Replace steam generators (SG) with a new design.	SAMA would lower the frequency of an SGTR.
135	Revise emergency operating procedures to direct that a faulted SG be isolated.	SAMA would reduce the consequences of an SGTR.
136	Direct SG flooding after a SGTR, prior to core damage.	SAMA would provide for improved scrubbing of SGTR releases.
137	Implement a maintenance practice that inspects 100% of the tubes in a SG.	SAMA would reduce the potential for an SGTR.
138	Locate RHR inside of containment.	SAMA would prevent intersystem LOCA (ISLOCA) out the RHR pathway.
139	Install additional instrumentation for ISLOCAs.	SAMA would decrease ISLOCA frequency by installing pressure of leak monitoring instruments in between the first two pressure isolation valves on low-pressure inject lines, RHR suction lines, and HPSI lines.
140	Increase frequency for valve leak testing.	SAMA could reduce ISLOCA frequency.
141	Improve operator training on ISLOCA coping.	SAMA would decrease ISLOCA effects.
142	Install relief valves in the CC System.	SAMA would relieve pressure buildup from an RCP thermal barrier tube rupture, preventing an ISLOCA.
143	Provide leak testing of valves in ISLOCA paths.	SAMA would help reduce ISLOCA frequency. At Kewaunee Nuclear Power Plant, four MOVs isolating RHR from the RCS were not leak tested.
144	Revise EOPs to improve ISLOCA identification.	SAMA would ensure LOCA outside containment could be identified as such. Salem Nuclear Power Plant had a scenario where an RHR ISLOCA could direct initial leakage back to the pressurizer relief tank, giving indication that the LOCA was inside containment.
145	Ensure all ISLOCA releases are scrubbed.	SAMA would scrub all ISLOCA releases. One example is to plug drains in the break area so that the break point would be covered with water.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
146	Add redundant and diverse limit switches to each containment isolation valve.	SAMA could reduce the frequency of containment isolation failure and ISLOCAs through enhanced isolation valve position indication.
147	Early detection and mitigation of ISLOCA	SAMA would limit the effects of ISLOCA accidents by early detection and isolation
148	Improved MSIV Design	This SAMA would improve isolation reliability and reduce spurious actuations that could be initiating events.
149	Proceduralize use of pressurizer vent valves during steam generator tube rupture (SGTR) sequences	Some plants may have procedures to direct the use of pressurizer sprays to reduce RCS pressure after an SGTR. Use of the vent valves would provide a back-up method.
150	Implement a maintenance practice that inspects 100% of the tubes in an SG	This SAMA would reduce the potential for a tube rupture.
151	Locate RHR inside of containment	This SAMA would prevent ISLOCA out the RHR pathway.
152	Install self-actuating containment isolation valves	For plants that do not have this, it would reduce the frequency of isolation failure.
Improvements in Reducing Internal Flooding Frequency		
153	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment.	SAMA would prevent flood propagation, for a plant where internal flooding from turbine building to safeguards areas is a concern.
154	Improve inspection of rubber expansion joints on main condenser.	SAMA would reduce the frequency of internal flooding, for a plant where internal flooding due to a failure of circulating water system expansion joints is a concern.
155	Implement internal flood prevention and mitigation enhancements.	This SAMA would reduce the consequences of internal flooding.
156	Implement internal flooding improvements such as those implemented at Fort Calhoun.	This SAMA would reduce flooding risk by preventing or mitigating rupture in the RCP seal cooler of the component cooling system an ISLOCA in a shutdown cooling line, an AFW flood involving the need to remove a watertight door.
157	Shield electrical equipment from potential water spray	SAMA would decrease risk associated with seismically induced internal flooding
158	Reduction in Reactor Building Flooding	This SAMA reduces the Reactor Building Flood Scenarios contribution to core damage and release.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
Improvements Related to Feedwater/Feed and Bleed Reliability/Availability		
159	Install a digital feedwater upgrade.	This SAMA would reduce the chance of a loss of main feedwater following a plant trip.
160	Perform surveillances on manual valves used for backup AFW pump suction.	This SAMA would improve success probability for providing alternative water supply to the AFW pumps.
161	Install manual isolation valves around AFW turbine-driven steam admission valves.	This SAMA would reduce the dual turbine-driven AFW pump maintenance unavailability.
162	Install accumulators for turbine-driven AFW pump flow control valves (CVs).	This SAMA would provide control air accumulators for the turbine-driven AFW flow CVs, the motor-driven AFW pressure CVs and SG power-operated relief valves (PORVs). This would eliminate the need for local manual action to align nitrogen bottles for control air during a LOOP.
163	Install separate accumulators for the AFW cross-connect and block valves	This SAMA would enhance the operator's ability to operate the AFW cross-connect and block valves following loss of air support.
164	Install a new CST	Either replace the existing tank with a larger one, or install a back-up tank.
165	Provide cooling of the steam-driven AFW pump in an SBO event	This SAMA would improve success probability in an SBO by: (1) using the FP system to cool the pump, or (2) making the pump self cooled.
166	Proceduralize local manual operation of AFW when control power is lost.	This SAMA would lengthen AFW availability in an SBO. Also provides a success path should AFW control power be lost in non-SBO sequences.
167	Provide portable generators to be hooked into the turbine driven AFW, after battery depletion.	This SAMA would extend AFW availability in an SBO (assuming the turbine driven AFW requires DC power)
168	Add a motor train of AFW to the Steam trains	For PWRs that do not have any motor trains of AFW, this would increase reliability in non-SBO sequences.
169	Create ability for emergency connections of existing or alternate water sources to feedwater/condensate	This SAMA would be a back-up water supply for the feedwater/condensate systems.
170	Use FP system as a back-up for SG inventory	This SAMA would create a back-up to main and AFW for SG water supply.
171	Procure a portable diesel pump for isolation condenser make-up	This SAMA would provide a back-up to the city water supply and diesel FP system pump for isolation condenser make-up.
172	Install an independent DG for the CST make-up pumps	This SAMA would allow continued inventory make-up to the CST during an SBO.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
173	Change failure position of condenser make-up valve	This SAMA would allow greater inventory for the AFW pumps by preventing CST flow diversion to the condenser if the condenser make-up valve fails open on loss of air or power.
174	Create passive secondary side coolers.	This SAMA would reduce CDF from the loss of Feedwater by providing a passive heat removal loop with a condenser and heat sink.
175	Replace current PORVs with larger ones such that only one is required for successful feed and bleed.	This SAMA would reduce the dependencies required for successful feed and bleed.
176	Install motor-driven feedwater pump.	SAMA would increase the availability of injection subsequent to MSIV closure.
177	Use Main feedwater pumps for a Loss of Heat Sink Event	This SAMA involves a procedural change that would allow for a faster response to loss of the secondary heat sink. Use of only the feedwater booster pumps for injection to the SGs requires depressurization to about 350 psig; before the time this pressure is reached, conditions would be met for initiating feed and bleed. Using the available turbine driven feedwater pumps to inject water into the SGs at a high pressure rather than using the feedwater booster alone allows injection without the time consuming depressurization.
Improvements in Core Cooling Systems		
178	Provide the capability for diesel driven, low pressure vessel make-up	This SAMA would provide an extra water source in sequences in which the reactor is depressurized and all other injection is unavailable (e.g., FP system)
179	Provide an additional HPSI pump with an independent diesel	This SAMA would reduce the frequency of core melt from small LOCA and SBO sequences
180	Install an independent AC HPSI system	This SAMA would allow make-up and feed and bleed capabilities during an SBO.
181	Create the ability to manually align ECCS recirculation	This SAMA would provide a back-up should automatic or remote operation fail.
182	Implement an RWT make-up procedure	This SAMA would decrease CDF from ISLOCA scenarios, some smaller break LOCA scenarios, and SGTR.
183	Stop LPSI pumps earlier in medium or large LOCAs.	This SAMA would provide more time to perform recirculation swap over.
184	Emphasize timely swap over in operator training.	This SAMA would reduce HEP of recirculation failure.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
185	Upgrade Chemical and Volume Control System to mitigate small LOCAs.	For a plant like the AP600 where the Chemical and Volume Control System cannot mitigate a Small LOCA, an upgrade would decrease the Small LOCA CDF contribution.
186	Install an active HPSI system.	For a plant like the AP600 where an active HPSI system does not exist, this SAMA would add redundancy in HPSI.
187	Change "in-containment" RWT suction from 4 check valves to 2 check and 2 air operated valves.	This SAMA would remove common mode failure of all four injection paths.
188	Replace 2 of the 4 safety injection (SI) pumps with diesel-powered pumps.	This SAMA would reduce the SI system CCF probability. This SAMA was intended for the System 80+, which has four trains of SI.
189	Align low pressure core injection or core spray to the CST on loss of suppression pool cooling.	This SAMA would help to ensure low pressure ECCS can be maintained in loss of suppression pool cooling scenarios.
190	Raise high pressure core injection/RCIC backpressure trip setpoints	This SAMA would ensure high pressure core injection/RCIC availability when high suppression pool temperatures exist.
191	Improve the reliability of the ADS.	This SAMA would reduce the frequency of high pressure core damage sequences.
192	Disallow automatic vessel depressurization in non-ATWS scenarios	This SAMA would improve operator control of the plant.
193	Create automatic swap over to recirculation on RWT depletion	This SAMA would reduce the human error contribution from recirculation failure.
194	Proceduralize intermittent operation of high pressure coolant injection (HPCI).	SAMA would allow for extended duration of HPCI availability.
195	Increase available NPSH for injection pumps.	SAMA increases the probability that these pumps will be available to inject coolant into the vessel by increasing the available NPSH for the injection pumps.
196	Modify Reactor Water Cleanup (RWCU) for use as a decay heat removal system and proceduralize use.	SAMA would provide an additional source of decay heat removal.
197	Control Rod Drive (CRD) Injection	SAMA would supply an additional method of level restoration by using a non-safety system.
198	Condensate Pumps for Injection	SAMA to provide an additional option for coolant injection when other systems are unavailable or inadequate

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
199	Align EDG to CRD for Injection	SAMA to provide power to an additional injection source during loss of power events
200	Re-open MSIVs	SAMA to regain the main condenser as a heat sink by re-opening the MSIVs.
201	Bypass RCIC Turbine Exhaust Pressure Trip	SAMA would allow RCIC to operate longer.
202	Passive High Pressure System	SAMA will improve prevention of core melt sequences by providing additional high pressure capability to remove decay heat through an isolation condenser type system
203	Suppression Pool Jockey Pump	SAMA will improve prevention of core melt sequences by providing a small makeup pump to provide low pressure decay heat removal from the RPV using the suppression pool as a source of water.
204	Improved High Pressure Systems	SAMA will improve prevention of core melt sequences by improving reliability of high pressure capability to remove decay heat.
205	Additional Active High Pressure System	SAMA will improve reliability of high pressure decay heat removal by adding an additional system.
206	Improved Low Pressure System (Firepump)	SAMA would provide FPS pump(s) for use in low pressure scenarios.
207	CUW Decay Heat Removal	This SAMA provides a means for Alternate Decay Heat Removal.
208	High Flow Suppression Pool Cooling	SAMA would improve suppression pool cooling.
209	Diverse Injection System	SAMA will improve prevention of core melt sequences by providing additional injection capabilities.
210	Alternate Charging Pump Cooling	This SAMA will improve the high pressure core flooding capabilities by providing the SI pumps with alternate gear and oil cooling sources. Given a total loss of Chilled Water, abnormal operating procedures would direct alignment of preferred Demineralized Water or the Fire System to the Chilled Water System to provide cooling to the SI pumps' gear and oil box (and the other normal loads).
Instrument Air/Gas Improvements		
211	Modify EOPs for ability to align diesel power to more air compressors.	For plants that do not have diesel power to all normal and back-up air compressors, this change would increase the reliability of IA after a LOOP.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
212	Replace old air compressors with more reliable ones	This SAMA would improve reliability and increase availability of the IA compressors.
213	Install nitrogen bottles as a back-up gas supply for SRVs.	This SAMA would extend operation of SRVs during an SBO and loss of air events (BWRs).
214	Allow cross connection of uninterruptible compressed air supply to opposite unit.	SAMA would increase the ability to vent containment using the hardened vent.
ATWS Mitigation		
215	Install MG set trip breakers in CR	This SAMA would provide trip breakers for the MG sets in the CR. In some plants, MG set breaker trip requires action to be taken outside of the CR. Adding control capability to the CR would reduce the trip failure probability in sequences where immediate action is required (e.g., ATWS).
216	Add capability to remove power from the bus powering the control rods	This SAMA would decrease the time to insert the control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has a rapid pressure excursion)
217	Create cross-connect ability for standby liquid control trains	This SAMA would improve reliability for boron injection during an ATWS event.
218	Create an alternate boron injection capability (back-up to standby liquid control)	This SAMA would improve reliability for boron injection during an ATWS event.
219	Remove or allow override of low pressure core injection during an ATWS	On failure on high pressure core injection and condensate, some plants direct reactor depressurization followed by 5 minutes of low pressure core injection. This SAMA would allow control of low pressure core injection immediately.
220	Install a system of relief valves that prevents any equipment damage from a pressure spike during an ATWS	This SAMA would improve equipment availability after an ATWS.
221	Create a boron injection system to back up the mechanical control rods.	This SAMA would provide a redundant means to shut down the reactor.
222	Provide an additional instrument system for ATWS mitigation (e.g., ATWS mitigation scram actuation circuitry).	This SAMA would improve instrument and control redundancy and reduce the ATWS frequency.
223	Increase the SRV reseat reliability.	SAMA addresses the risk associated with dilution of boron caused by the failure of the SRVs to reseat after standby liquid control (SLC) injection.

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SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
224	Use CRD for alternate boron injection.	SAMA provides an additional system to address ATWS with SLC failure or unavailability.
225	Bypass MSIV isolation in Turbine Trip ATWS scenarios	SAMA will afford operators more time to perform actions. The discharge of a substantial fraction of steam to the main condenser (i.e., as opposed to into the primary containment) affords the operator more time to perform actions (e.g., SLC injection, lower water level, depressurize RPV) than if the main condenser was unavailable, resulting in lower human error probabilities
226	Enhance operator actions during ATWS	SAMA will reduce human error probabilities during ATWS
227	Guard against SLC dilution	SAMA to control vessel injection to prevent boron loss or dilution following SLC injection.
228	ATWS Sized Vent	This SAMA would provide the ability to remove reactor heat from ATWS events.
229	Improved ATWS Capability	This SAMA includes items which reduce the contribution of ATWS to core damage and release frequencies.
Other Improvements		
230	Provide capability for remote operation of secondary side relief valves in an SBO	Manual operation of these valves is required in an SBO scenario. High area temperatures may be encountered in this case (no ventilation to main steam areas), and remote operation could improve success probability.
231	Create/enhance RCS depressurization ability	With either a new depressurization system, or with existing PORVs, head vents, and secondary side valve, RCS depressurization would allow earlier low pressure ECCS injection. Even if core damage occurs, low RCS pressure would alleviate some concerns about HPME.
232	Make procedural changes only for the RCS depressurization option	This SAMA would reduce RCS pressure without the cost of a new system
233	Defeat 100% load rejection capability.	This SAMA would eliminate the possibility of a stuck open PORV after a LOOP, since PORV opening would not be needed.
234	Change CRD flow CV failure position	Change failure position to the "fail-safest" position.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
235	Install secondary side guard pipes up to the MSIVs	This SAMA would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. This SAMA would also guard against or prevent consequential multiple SGTR following a Main Steam Line Break event.
236	Install digital large break LOCA protection	Upgrade plant instrumentation and logic to improve the capability to identify symptoms/precursors of a large break LOCA (leak before break).
237	Increase seismic capacity of the plant to a high confidence, low pressure failure of twice the Safe Shutdown Earthquake.	This SAMA would reduce seismically -induced CDF.
238	Enhance the reliability of the demineralized water (DW) make-up system through the addition of diesel-backed power to one or both of the DW make-up pumps.	Inventory loss due to normal leakage can result in the failure of the CC and the SRW systems. Loss of CC could challenge the RCP seals. Loss of SRW results in the loss of three EDGs and the containment air coolers (CACs).
239	Increase the reliability of SRVs by adding signals to open them automatically.	SAMA reduces the probability of a certain type of medium break LOCA. Hatch evaluated medium LOCA initiated by an MSIV closure transient with a failure of SRVs to open. Reducing the likelihood of the failure for SRVs to open, subsequently reduces the occurrence of this medium LOCA.
240	Reduce DC dependency between high-pressure injection system and ADS.	SAMA would ensure containment depressurization and high-pressure injection upon a DC failure.
241	Increase seismic ruggedness of plant components.	SAMA would increase the availability of necessary plant equipment during and after seismic events.
242	Enhance RPV depressurization capability	SAMA would decrease the likelihood of core damage in loss of HPCI scenarios
243	Enhance RPV depressurization procedures	SAMA would decrease the likelihood of core damage in loss of HPCI scenarios
244	Replace mercury switches on FPSs	SAMA would decrease probability of spurious fire suppression system actuation given a seismic event+D114
245	Provide additional restraints for CO_2 tanks	SAMA would increase availability of FP given a seismic event.
246	Enhance control of transient combustibles	SAMA would minimize risk associated with important fire areas.
247	Enhance fire brigade awareness	SAMA would minimize risk associated with important fire areas.
248	Upgrade fire compartment barriers	SAMA would minimize risk associated with important fire areas.

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SAMA ID number	SAMA title	Result of potential enhancement
249	Enhance procedures to allow specific operator actions	SAMA would minimize risk associated with important fire areas.
250	Develop procedures for transportation and nearby facility accidents	SAMA would minimize risk associated with transportation and nearby facility accidents.
251	Enhance procedures to mitigate Large LOCA	SAMA would minimize risk associated with Large LOCA
252	Computer Aided Instrumentation	SAMA will improve prevention of core melt sequences by making operator actions more reliable.
253	Improved Maintenance Procedures/Manuals	SAMA will improve prevention of core melt sequences by increasing reliability of important equipment
254	Improved Accident Management Instrumentation	SAMA will improve prevention of core melt sequences by making operator actions more reliable.
255	Remote Shutdown Station	This SAMA would provide the capability to control the reactor in the event that evacuation of the MCR is required.
256	Security System	Improvements in the site's security system would decrease the potential for successful sabotage.
257	Improved Depressurization	SAMA will improve depressurization system to allow more reliable access to low pressure systems.
258	Safety Related CST	SAMA will improve availability of CST following a Seismic event
259	Passive Overpressure Relief	This SAMA would prevent vessel overpressurization.
260	Improved Operating Response	Improved operator reliability would improve accident mitigation and prevention.
261	Operation Experience Feedback	This SAMA would identify areas requiring increased attention in plant operation through review of equipment performance.
262	Improved SRV Design	This SAMA would improve SRV reliability, thus increasing the likelihood that sequences could be mitigated using low pressure heat removal.
263	Increased Seismic Margins	This SAMA would reduce the risk of core damage and release during seismic events.
264	System Simplification	This SAMA is intended to address system simplification by the elimination of unnecessary interlocks, automatic initiation of manual actions or redundancy as a means to reduce overall plant risk.

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SAMA ID number	SAMA title	Result of potential enhancement
265	Train operations crew for response to inadvertent actuation signals	This SAMA would improve chances of a successful response to the loss of two 120V AC buses, which may cause inadvertent signal generation.
266	Install tornado protection on gas turbine generators	This SAMA would improve onsite AC power reliability.