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ISSUE 107

MAIN TRANSFORMER FAILURES

Letter Report

March 28, 1997

Prepared by

F. Sciacca, W. Thomas

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J. Hopenfeld, NRC Task Manager

Prepared for

Division of Engineering Technology
Office of Nuclear Regulatory Research
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
NRC Job Code W6650

Science & Engineering Associates, Inc.

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1.0 SAFETY ISSUE DESCRIPTION

Generic safety issue (GSI) 107, "Main Transformer Failures," was originally opened to address concerns related to seven main transformer failures that occurred at North Anna during a 26-month period in the early 1980s. Five of these transformer failures resulted in reactor trips. Three of these failures involved transformer tank rupture, with two fires. One of the fires spread beyond the transformer bay to the turbine bay.

The term "main transformer" refers to a transformer used to transfer electrical output from a plant's main generator onto the offsite grid. Other terminology typically used to represent main transformers includes the following: main output transformer, main power transformer, main step-up transformer, and main unit transformer. The main transformer function is commonly accomplished with a main step-up bank of three individual single-phase transformers. Plants may have a single main transformer bank or two parallel 50% capacity main transformer banks. Plant loads are not powered from main transformers. Instead, plant loads typically receive power from a "unit auxiliary transformer" directly connected to the main generator leads, and/or from one or more transformers connected to the offsite power grid, such as startup, shutdown, or reserve transformers.

This report summarizes an analysis to support reprioritization of GSI-107. This updated analysis is based on a survey of transformer failure events that reflects plant experience through 1996.

ISSUE SUMMARY WORK SHEET

ISSUE NO./TITLE: 107, Main Transformer Failures

SUMMARY OF PROBLEM AND PROPOSED RESOLUTION:

The concern of this issue is the generic safety implications associated with main transformer failures at U.S. light water reactors (LWRs). Safety issue resolution involves licensee reviews and evaluations of main transformer problems and enhancement of fire protection capabilities where necessary. Costs are shown both in the traditional undiscounted format and with discounting applied to the future expenditures and savings. A 7% discount rate was used to evaluate costs for the discounted case.

AFFECTED PLANTS

BWR: Operating = 37 Planned = 0
PWR: Operating = 73 Planned = 0

RISK/DOSE RESULTS (person-rem)

PUBLIC RISK REDUCTION =	1.1E+03
OCCUPATIONAL DOSES:	
SIR Implementation =	0
SIR Operation/Maintenance =	0
Total of Above =	0
Accident Avoidance =	7

COST RESULTS ($\$10^6$)

	Undiscounted	Discounted
INDUSTRY COSTS:		
SIR Implementation =	4.53	4.53
SIR Operation/Maintenance =	(-)8.6	(-)4.41
Total of Above =	(-)4.07	0.12
Accident Avoidance =	(-)1.0	(-)0.33
NRC COSTS:		
SIR Development =	0.10	0.10
SIR Implementation =	0.56	0.56
SIR Operation/Maintenance Review =	2.1	0.69
Total of Above =	2.72	1.35

2.0 SAFETY ISSUE RISK AND DOSE

The public risk reduction and occupational dose associated with the issue resolution are estimated in this section. Results are summarized in Tables 1 and 2, respectively. The analyses are conducted for a representative PWR and a representative BWR. The Oconee-3 PRA (Andrews, et al., 1983, Appendix A) risk equations have been assumed to be representative of all PWRs for this analysis. The Grand Gulf-1 PRA (Andrews, et al., 1983, Appendix B) was used to derive estimates of core damage frequency reduction and occupational dose increase for BWRs.

Table 1. Public Risk Reduction Work Sheet

1. Title and Identification Number of Safety Issue:

   Main Transformer Failures. Issue 107

2. Affected Plants (N) and Average Remaining Lives (T):

	N	T (yr)
All PWRs	73	22
All BWRs	37	21
All plants	110	22

3. Plants Selected for Analysis:

   A PWR and a BWR are assumed to be representative of each type of reactor. The safety analyses are conducted for Oconee-3 for PWRs and Grand Gulf 1 for BWRs.

4. Parameters Affected by SIR:

   For the representative PWR, the primary affected parameters are:

   T_1 Loss of offsite power (LOSP) transient
   T_2 Loss of power conversion system transient caused by other than LOSP (general transient)

   For the representative BWR, the primary affected parameters are:

   T_1 Loss of offsite power (LOSP) transient
   T_{23} Any transient other than LOSP which requires an emergency reactor shutdown (general transient).

5. Base-Case Values for Affected Parameters:

   For the representative PWR and BWR, the base-case LOSP frequency is:

   $T_1 = 0.2/\text{ry}^*$

   For the representative PWR, the base-case transient frequency is:

   $T_2 = 3/\text{ry}$

*The term "ry" refers to a reactor year.

For the representative BWR, the base-case transient frequency is:

$T_{23} = 7.0/ry$

6. Affected Accident Sequences and Base-Case Frequencies:

Listed below are the affected accident sequences and base-case frequencies (ry). The associated containment failure modes (α, β, δ, γ, ε) are defined in Appendices A and B of NUREG/CR-2800. The release categories (i.e., PWR-1, BWR-1, etc.) are those defined in Appendix D of NUREG/CR-2800.

Oconee-3:

Transient Sequences		LOSP Sequences	
Sequence ID	Release Category/ Frequency (ry)	Sequence ID	Release Category/ Frequency (ry)
T_2MLU	γ (PWR-3) = 6.0E-7 β (PWR-5) = 8.8E-9 ε (PWR-7) = 6.0E-7	T_1MLU	γ (PWR-3) = 1.0E-6 β (PWR-5) = 1.5E-8 ε (PWR-7) = 1.0E-6
T_2MQH	γ (PWR-3) = 5.5E-6 β (PWR-5) = 8.0E-8 ε (PWR-7) = 5.5E-6	$T_1(B_3)MLU$	γ (PWR-3) = 1.1E-6 β (PWR-5) = 1.6E-8 ε (PWR-7) = 1.1E-6
T_2MQFH	γ (PWR-2) = 2.5E-6 β (PWR-4) = 3.7E-8 ε (PWR-6) = 2.5E-6	T_1MLUO	γ (PWR-3) = 2.7E-6 β (PWR-5) = 3.9E-8 ε (PWR-7) = 2.7E-6
T_2MLUO	γ (PWR-3) = 4.1E-6 β (PWR-5) = 5.9E-8 ε (PWR-7) = 4.1E-6		
T_2KMU	γ (PWR-3) = 3.9E-6 β (PWR-5) = 5.7E-8 ε (PWR-7) = 3.9E-6		
T_2MQD	γ (PWR-3) = 7.5E-7 β (PWR-5) = 1.1E-8 ε (PWR-7) = 7.5E-7		

Grand Gulf:

Transient Sequences		LOSP Sequences	
Sequence ID	Release Category/ Frequency (ry)	Sequence ID	Release Category/ Frequency (ry)
$T_{23}PQI$	α (BWR-1) = 3.7E-8 δ (BWR-2) = 3.7E-6	T_1PQI	α (BWR-1) = 1.6E-8 δ (BWR-2) = 1.6E-6
$T_{23}PQE$	γ (BWR-3) = 2.7E-7 δ (BWR-4) = 2.7E-7	T_1PQE	γ (BWR-3) = 1.2E-7 δ (BWR-4) = 1.2E-7
$T_{23}QW$	δ (BWR-2) = 1.2E-5	T_1QW	δ (BWR-2) = 6.2E-6
$T_{23}C$	δ (BWR-2) = 5.4E-6	T_1QUV	γ (BWR-3) = 9.5E-7 δ (BWR-4) = 9.5E-7

7. <u>Affected Release Categories and Base-Case Frequencies</u>:

Oconee:

Release		TRAN (T_2)		LOSP (T_1)	
Release Category	Dose Consequence Factor (person-rem)	Frequency (ry)	Risk (person-rem/ry)	Frequency (ry)	Risk (person-rem/ry)
PWR-2	4.8E+6	2.500E-6	12.000		
PWR-3	5.4E+6	1.485E-5	80.190	[illegible].800E-6	25.920
PWR-4	2.7E+6	3.700E-8	0.100		
PWR-5	1.0E+6	2.158E-7	0.216	7.000E-8	0.070
PWR-6	1.5E+5	2.500E-6	0.375		
PWR-7	2.3E+3	1.485E-5	0.034	4.800E-6	0.011
Total		3.495E-5	92.915	9.670E-6	26.001

Grand Gulf:

Release		TRAN (T_2)		LOSP (T_1)	
Release Category	Dose Consequence Factor (person-rem)	Frequency (ry)	Risk (person-rem/ry)	Frequency (ry)	Risk (person-rem/ry)
BWR-1	5.4E+6	3.700E-8	0.200	1.600E-8	0.086
BWR-2	7.1E+6	2.110E-5	149.810	7.800E-6	55.380
BWR-3	5.1E+6	2.700E-7	1.377	1.070E-6	5.457
BWR-4	6.1E+5	2.700E-7	0.165	1.070E-6	0.653
Total		2.168E-5	151.552	9.956E-6	61.576

8. <u>Base-Case, Affected Core Damage Frequency ($\bar{F}$)</u>:

$$\bar{F}^{TRAN}_{PWR} = 3.495E-05/py \qquad \bar{F}^{TRAN}_{BWR} = 2.168E-05/py$$

$$\bar{F}^{LOSP}_{PWR} = 9.670E-06/py \qquad \bar{F}^{LOSP}_{BWR} = 9.956E-06/py$$

$$\bar{F}^{TOTAL}_{PWR} = 4.462E-05/py \qquad \bar{F}^{TOTAL}_{BWR} = 3.164E-05/py$$

Note: These values were calculated by summing the Grand Gulf-1 and Oconee-3 PRA sequence frequency data presented in Steps 6 and 7. The values contain excess significant figures in order to compute the difference between the base-case and adjusted-case.

9. Base-Case, Affected Public Risk (W):

$$W_{PWR} = W_{PWR}^{TRAN} + W_{PWR}^{LOSP} = (92.915+26.001)\ person\text{-}rem/py = 118.916\ person\text{-}rem/py$$

$$W_{BWR} = W_{BWR}^{TRAN} + W_{BWR}^{LOSP} = (151.552+61.576)\ person\text{-}rem/py = 213.128\ person\text{-}rem/py$$

10. Adjusted-Case, Affected Values and Affected Parameters:

As discussed in Attachment 1, SIR is assumed to reduce the frequency of general transients and LOSP at PWRs and BWRs by enhancing the reliability of main transformers and preventing potential fires that may result from main transformer failures from spreading to other vital areas of the plant. To model the effects of SIR on plant risk, the transient frequencies given in NUREG/CR-2800 (Andrews, et al., 1983) were modified to reduce the general transient and LOSP frequencies by the amount equivalent to 50% of reactor trips caused by main transformer failures.

For PWRs, the adjusted case values are:

T_2 = 3/ry - 0.0125/ry = 2.9875/ry; T_1 = 0.2/ry - 0.00065/ry = 0.19935/ry

For BWRs, the adjusted case values are:

T_{23} = 7/ry - 0.0125/ry = 6.9875/ry; T_1 = 0.2/ry - 0.00065/ry = 0.19935/ry

11, 12. Steps Leading to Calculation of Adjusted-Case Affected Accident Sequence Frequencies and Adjusted-Case Frequencies for Affected Release Categories:

The Oconee-3 and Grand Gulf-1 data listed in Steps 8-10 above were used to calculate the adjusted-case affected core damage frequencies and public risk values and the changes in core damage frequency and public risk associated with SIR. These calculations are shown below in Steps 13-17.

13. Adjusted-Case Affected Core Damage Frequency (F*):

$$\bar{F}^{*TRAN}_{PWR} = 3.480E\text{-}05/py \qquad \bar{F}^{*TRAN}_{BWR} = 2.164E\text{-}05/py$$

$$\bar{F}^{*LOSP}_{PWR} = 9.639E\text{-}06/py \qquad \bar{F}^{*LOSP}_{BWR} = 9.924E\text{-}06/py$$

$$\bar{F}^{*TOTAL}_{PWR} = 4.444E\text{-}05/py \qquad \bar{F}^{*TOTAL}_{BWR} = 3.156E\text{-}05/py$$

14. Adjusted-Case, Affected Public Risk (W*):

$$W^{*}_{PWR} = W^{*TRAN}_{PWR} + W^{*LOSP}_{PWR} = (92.528+25.916)\ person\text{-}rem/py = 118.444\ person\text{-}rem/py$$

$$W^{*}_{BWR} = W^{*TRAN}_{BWR} + W^{*LOSP}_{BWR} = (151.281+61.376)\ person\text{-}rem/py = 212.657\ person\text{-}rem/py$$

15. Reduction in Core Damage Frequency ($\Delta\bar{F}$):

$$\Delta\bar{F}_{PWR}^{TRAN} = 1.456E\text{-}07/py \qquad \Delta\bar{F}_{BWR}^{TRAN} = 3.871E\text{-}08/py$$

$$\Delta\bar{F}_{PWR}^{LOSP} = 3.143E\text{-}08/py \qquad \Delta\bar{F}_{BWR}^{LOSP} = 3.236E\text{-}08/py$$

$$\Delta\bar{F}_{PWR}^{TOTAL} = 1.770E\text{-}07/py \qquad \Delta\bar{F}_{BWR}^{TOTAL} = 7.107E\text{-}08/py$$

16. Per-Plant Reduction in Public Risk (ΔW):

$$\Delta W_{PWR}^{TRAN} = 0.39 \ person\text{-}rem/py \qquad \Delta W_{BWR}^{TRAN} = 0.27 \ person\text{-}rem/py$$

$$\Delta W_{PWR}^{LOSP} = 0.08 \ person\text{-}rem/py \qquad \Delta W_{BWR}^{LOSP} = 0.20 \ person\text{-}rem/py$$

$$\Delta W_{PWR}^{TOTAL} = 0.47 \ person\text{-}rem/py \qquad \Delta W_{BWR}^{TOTAL} = 0.47 \ person\text{-}rem/py$$

17. Total Public Risk Reduction, ΔW (Total):

Best Estimate (person-rem)	Error Bounds (person-rem)**	
	Upper	Lower
1.1E+03	5.0E+03	50

**See Attachment to Table 1 for development of upper and lower bounds.

Table 2. Occupational Dose Work Sheet

1. Title and Identification Number of Safety Issue:

Main Transformer Failures, Issue 107

2. Affected Plants (N):

All 110 currently-operating plants are assumed to be affected. This includes 73 PWRs and 37 BWRs.

3. Average Remaining Lives of Affected Plants (T):

	$\bar{T}$ (yr)
All PWRs	22
All BWRs	21
All plants	22

4. Per-Plant Occupational Dose Reduction Due to Accident Avoidance, $\Delta(\bar{F}D_R)$:

Using 21,000 person-rem for D_R, then

PWR: $\Delta(\bar{F}D_R)$ = (21,000 person-rem)(1.77E-7/ry) = 3.7E-3 person-rem/ry
BWR: $\Delta(\bar{F}D_R)$ = (21,000 person-rem)(0.711E-7/ry) = 1.5E-3 person-rem/ry

5. Total Occupational Dose Reduction Due to Accident Avoidance (ΔU):

Best Estimate (person-rem)	Error Bounds (person-rem)	
	Upper	Lower
7.2	21	0

6 to 12. Steps Leading to Total Occupational Exposures for SIR Implementation, Operation, and Maintenance:

SIR is assumed to not involve any labor in radiation zones. This is because the main transformers are not located in a building in which radioactive materials are used or stored and thus the radiation dose rates would be zero. SIR does not require any entries into containment or into the reactor building. As a result, total occupational exposures for SIR implementation, operation, and maintenance are 0.

3.0 SAFETY ISSUE COSTS

The industry and NRC costs associated with resolution of this safety issue are estimated in this section. The results are summarized in Table 3.

Table 3. Safety Issue Cost Work Sheet

1. Title and Identification Number of Safety Issue:

   Main Transformer Failures, Issue 107

2. Affected Plants (N):

   All 110 currently operating plants are assumed to be affected.

3. Average Remaining Lives of Affected Plants ($\bar{T}$):

		$\bar{T}$ (cy)***
Operating:	PWRs	22
	BWRs	21
All plants:		22

Industry Costs (Steps 4 through 12):

4. Per-Plant Industry Cost Savings Due to Accident Avoidance, $\Delta(\bar{F}A)$:

   Avoidance of accidents results in savings due to (a) avoided cleanup and decontamination costs and (b) avoided replacement energy costs due to extended or permanent shutdown of the plant. Cleanup and decontamination costs for a large accident are estimated to be about \$1.69E+09 (1996\$). Cumulative avoided replacement energy costs, assuming a large accident would result in permanent shutdown of the plant, are estimated to be \$28.63E+09 for a typical PWR and about \$21.09E+09 for a typical BWR. On an undiscounted basis these values are equivalent to \$1.301E+09/ry for PWRs and \$1.004E+09 for BWRs (in 1996\$). (NUREG/CR-5595, Rev. 1)

   PWR: $\Delta(\bar{F}A)$ = (1.77E-07/ry)(\$2.99E+09) = \$530/ry
   BWR: $\Delta(\bar{F}A)$ = (0.711E-07/ry)(\$2.70E+09) = \$191/ry

5. Total Industry Cost Savings Due to Accident Avoidance (ΔH):

Best Estimate (1996 \$)	Error Bounds (1996 \$)	
	Upper	Lower
(-)\$1.0E+06	(-)\$3.4E+06	(-)\$0.8E+05

6. Per-Plant Industry Resources for SIR Implementation:

   For all operating plants, it is assumed that the NRC would issue a generic letter or bulletin requiring all plants to review the design and installation of main transformers and associated fire protection systems, control circuits, and operating and maintenance procedures. The assumed resource requirements for this review are:

***The term "cy" refers to a calendar year.

Labor =	2	person-weeks/plant to evaluate fire protection system(s)
	1	person-weeks/plant to review protective circuitry
	4	person-weeks/plant to review operating and maintenance procedures
	7	person-weeks/plant for reviews and evaluations

The reviews would be expected to identify the need to revise some or all of the affected procedures. The assumption has been made that two routine procedural changes and one complex procedural change would result. The associated cost to revise these procedures is $6,670 (1996$) per plant (NUREG/CR-4627, Rev. 2).

In addition, affected plant staff would have to be trained in the updated operation and maintenance procedures. Costs associated with the updated training are based on the assumption that 25 plant staff per plant would be affected, and that the implementation training would require 8 hours of class time. Training manuals would also have to be revised; the assumption has been made that about 15 pages of these manuals would be changed. The resulting costs, based on NRC's Generic Cost Estimates Handbook (NUREG/CR-4627, Rev. 2) for the implementation phase training is $7,510/plant.

As a result of the reviews conducted at all plants, it is assumed that 10% of the plants would require modifications to the fire protection system and rerouting of cables around the main transformer areas. The assumed resource requirements for the plants requiring modifications are:

Labor =	2	person-weeks/plant to plan installation and testing
	2	person-weeks/plant for acceptance testing
	4	person-weeks/plant for SIR Implementation

Those plants making physical modifications are expected to expend more resources in developing or revising procedures associated with main transformers operation and maintenance and with the associated fire protection systems and control circuits. The procedural changes for these plants are expected to be equivalent to making three complex changes. The corresponding cost is $13,450/plant.

Additional hardware requirements for those plants requiring modifications include: an additional drain, gravel and concrete to slope the area around the transformers and construct dikes; additional power lines to route power to the buildings; additional breakers to protect equipment connected to the auxiliary transformer; and longer fire hoses. The hardware and installation labor costs for the plants requiring modifications are itemized below:

Dike (250-ft long, 4-ft high)	$ 5,960
Concrete and gravel	25,130
Power lines (1,000 ft)	12,260
Poles (10 @ $1724 each)	17,240
Breakers (2 @ $7,260 each)	14,520
Fire hose/storage cabinet (100-ft)	800
Total (1996 dollars)	$75,900

The foregoing physical modification costs do not include the effort needed for engineering and quality assurance. Engineering/QAQC costs are estimated to be 25% of the direct costs of the physical modifications, or $18,975 (NUREG/CR-4627, Rev. 2).

7. Per-Plant Industry Cost for SIR Implementation (I):

All plants (review and evaluation)

Labor = (7 person-wks)($2270/person-wk)	=	$15,900
Revise maintenance & operation procedures	=	6,670
Revise staff training	=	7,510
Total (all plants, review and evaluation phase):		$30,080

10% of plants (hardware modifications)

Labor = 4 person-wks)($2270/person-wk)	=	$ 9,080
Hardware	=	75,900
Revise maintenance & operation procedures*	=	6,780
Engineering/QA/QC	=	18,975
Incremental Costs (physical modification plants):		$110,735

*Incremental costs relative to plants not requiring physical modifications, i.e., $13,450 - $6,670 = $6,780 (see above and previous page)

8. Total Industry Cost for SIR Implementation (NI):

NI = (110 plants)($30,080/plant) + (11 plants)($110,735/plant)
= $4.5E+6

9. Per-Plant Industry Labor for SIR Operation and Maintenance:

Labor would be expended annually to perform periodic reviews of pertinent procedures, operations, and maintenance activities for the main transformer. In addition, affected plant staff are assumed to receive a one-half day refresher training course on transformer maintenance, fire fighting, and related areas. Those plants with physical modifications are further assumed to expend an additional 1.0 person-week for inspections, cleanup, and related activities.

All plants:

Labor = 0.2 person-wk/cy	for periodic review of main transformer procedures, operations, and maintenance
Training expenses: $2,840/cy	for one-half day refresher training course for 25 affected plant personnel

Plants requiring hardware modifications:

Labor = 1.0 person-wk/cy	for periodic maintenance/inspection of drains and new diked areas; removal of trash from drains; etc.

Effects of Improved Transformer Reliability

Many of the transformer failures reported in Attachment 1 to Table 1 indicate that human error was involved and that failures might have been avoided with enhanced maintenance and more diligent inspections of the main transformers. The revised procedures and improved training for affected plant personnel is expected to improve transformer reliability through reduced operator errors and detection of degraded conditions prior to actual failure of the equipment. These actions, coupled with the physical modifications made to 10% of the plant population, are expected to reduce main transformer failures by about 50%, from 0.026 events/ry to 0.013/ry. Reducing the number of transformer failures will benefit licensees through avoided costs of

replacing damaged transformers and other affected equipment, as well as avoiding plant down time (replacement energy costs) needed to repair or replace the damaged unit.

Main transformers for large nuclear power plants are quite expensive. Large transformers are estimated to cost in excess of $2 million, including installation labor. However, often these large transformers are made up of two half-capacity units or three single-phase transformers. The reported failure data indicates that a failure of a sub-unit only infrequently causes damage to the other sub-units. Therefore, the assumption has been made here that a transformer failure will result in replacement of only a sub-unit rather than replacement of the entire main transformer. The cost of removing the damaged unit and replacing it with a new unit is estimated to be $940,000 (1996$), assuming that only one of the three single-phase transformers is damaged and needs replacement. The further assumption has been made that only 25% of the failure events result in major damage of this type. The resulting avoided transformer replacement costs are about (-)$2,940/ry.

Avoided replacement power costs associated with reducing the number of reactor trips per year caused by main transformer failures were also addressed. As above, SIR is postulated to reduce the frequency of plant trips caused by transformer failures by 0.013/ry. This trip frequency is based on the conditional probability of 0.95 that a main transformer failure results in a reactor trip (see Table B, Attachment 1 to Table 1). If the shutdown was caused by a minor transformer-related failure, it was estimated that the plant would be down for 12 hours. A major transformer failure was assumed to cause the plant to be down for three days to replace or repair the damaged unit. Consistent with previous estimates, the assumptions were made that 25% of transformer failures result in major damage to the units while 75% of these events result in minor damage which can be rapidly repaired. This approach results in an estimated downtime of 1.125 days/ry for transformer-related failures. Using an average replacement power cost of $3.1E+5/day for PWRs and $2.5E+5/day for BWRs (NUREG/CR-5595, Rev. 1), the avoided annual costs are about $4.3E+3/plant for PWRs and about $3.5E+3/plant for BWRs. The weighted average annual savings due to avoided replacement energy costs are estimated to be $4,025/plant.

10. Per-Plant Industry Cost for Operation and Maintenance (I_o):

For all plants:

Review of procedures: (0.2 person-wk/cy)($2270/person-wk) = $450/cy
Refresher training: $2,840/cy
I_o = $3,300/cy

For plants requiring hardware modifications (costs in addition to I_o for all plants):

I_o = (1.0 person-wk/cy)($2270/person-wk) = $2,270/cy

Avoided costs for transformer replacement:

I_o = -(0.013 transformer flrs/ry)(0.25 major failures/event)($9.4E+5/event)
= -$3,050/ry = -$3,050/cy (see notes 1, 2)

Avoided replacement power costs:

I_o = -$4,025/ry =- $4,025/cy (see notes 1, 2)

Notes: (1) Negative sign (-) indicates avoided costs. (2) Per p. 17, "ry" can be approximated by "cy".

11. Total Industry Cost for SIR Operation and Maintenance (NTI_o):

NTI_o = (110 plants)($3,300/cy)(22 cy) + (11 plants)($2270/cy)(22 cy)
- (110 plants)(22 cy)($3,050/cy) - (110 plants)(22 cy)($4,025/cy)
= -$8.6E+6

12. Total Industry Cost (S_I):

Best Estimate (1996 $)	Error Bounds (1996 $)	
	Upper	Lower
(-)$5.1E+06	(-)$20.0E+06	$7.6E+06

NRC Costs (Steps 13 through 21)

13. NRC Resources for SIR Development:

The NRC costs for developing the SIR include four person-weeks to issue a generic letter or bulletin to the licensees (includes technical, legal, and administrative staff support) 6 person-months to review licensee responses to the letter, assess the differences between plant designs, and research potential implementation measures (assumed to be provided by a contractor), and 4 person-wks of NRC technical staff labor to monitor the contractor. SIR development also includes issuance of revised design guidance to the licensees related to adequate main transformer designs and procedures. It is estimated that an additional 6 person-wks of NRC technical, legal, and administrative staff labor are needed to develop, approve, and issue the revised guidance.

The cost for NRC staff is assumed to be $53.24/hr (1996$) and is taken to be partially burdened rather than fully burdened (NUREG/CR-4627, Rev. 2). The cost for supporting contractor efforts are taken to be $70/hr fully burdened.

14. Total NRC Cost for SIR Development (C_D):

Labor (14 person-weeks)($2,130/person-week)	=	$3.0E+04
Contract Support	=	7.3E+04
C_D	=	$10.3E+04

15. Per-Plant NRC Labor for Support of SIR Implementation:

NRC labor to support SIR implementation consists of reviewing utility plans to comply with the revised guidance plus an onsite inspection by the resident inspector to review the plans. The labor requirements are:

Review and approval of license's plans	2 person-wks/plant
Onsite inspection	0.4 person-wks/plant
Total	2.4 person-wks/plant

16. Per-Plant NRC Cost for Support of SIR Implementation (C):

C = (2.4 person-wk/plant)($2,130/person-wk) = $5.1E+03/plant

17. Total NRC Cost for Support of SIR Implementation (NC):

NC = (110 plants)($5.1E+03/plant) = $5.6E+05

18. Per-Plant NRC Labor for Review of SIR Operation and Maintenance:

NRC Labor to review SIR operation and maintenance is assumed to be primarily integrated with other NRC inspection activities. However, additional labor is assumed to be needed for enhanced reviews of main transformer testing/maintenance programs, operability of the fire protection system, and the effectiveness of revised hardware configurations. The NRC labor requirements for these enhanced reviews are estimated at about 2 person-days per plant per calendar year.

19. Per-Plant NRC Cost for Review of SIR Operation and Maintenance:

C_o = (0.4 person-wk/cy)($2,130/person-wk) = $850/cy

20. Total NRC Cost for Review of SIR Operation and Maintenance (NTC_o):

NTC_o = (110 plants)(22 cy)($850/cy) = $2.1E+06

21. Total NRC Cost (S_N):

Best Estimate (1996 $)	Error Bounds (1996 $)	
	Upper	Lower
$2.8E+06	$3.5E+06	$2.2E+06

Attachment 1 to Table 1

Data Review and Evaluation

This re-prioritization of GSI 107 is based on analysis methods similar to those used in the earlier GSI 107 prioritization, namely the analysis methods described in NUREG/CR-2800. Consistent with the earlier prioritization, this re-prioritization uses Oconee-3 as the representative PWR and Grand Gulf-1 as the representative BWR.

As noted in NUREG/CR-2800, nuclear plant PRAs typically integrate main transformer failures into a category of transients that result from loss of network load, rather than explicitly model main transformer failures. By including main transformer failures into a transient accident class, the PRAs implicitly assume that main transformer failures do not by themselves lead to a loss of offsite power (LOSP). As will be demonstrated shortly, this assumption is valid most, but not all, of the time. Because there is a non-zero probability that a main transformer failure initiating event will cause a LOSP, it is necessary that two categories of affected parameters be analyzed to determine Safety Issue Resolution (SIR) public risk and core damage frequency reductions, namely: (1) a loss of power conversion system (PCS) transient caused by other than LOSP, and (2) LOSP. For the loss of PCS transient, the pertinent affected initiating event parameters are T_2 for Oconee and T_{23} for Grand Gulf. For the LOSP condition, the affected initiating event parameter at each plant is T_1.

An important element of this re-prioritization task was to gather and review previous events associated with main transformer failures. Previous plant experience is important, because it can help support quantification of the frequency of transformer failures, and can also provide information related to the impact on other plant systems/functions, such as the availability of offsite power. Several methods were used were used to gather historical data, including computer searches of materials contained in the NRC's Public Document Room (PDR) and reviews of various NUREG and industry reports. Particular emphasis was given to the identification of events involving transformer explosions. Historical events occurring during the 17-year period from 1980 through 1996 were retained to support the GSI 107 re-prioritization.

While the focus of the event and documentation searches was related to failures of main transformers, a limited effort was also made to review failure experience associated with some other categories of outdoor site transformers, such as unit auxiliary transformers and startup transformers. The data acquired on these other categories of transformers were used to gain additional insights regarding the amount of damage that can be caused by transformer explosions and fires.

The historical data survey described above resulted in the identification of 40 main transformer failures from 1980 through 1996. These events are summarized in Table A. This table lists each event in descending order of the event date. For each event, several items are provided, including the affected plant, a summary of the incident, reactor trip and LOSP status, transformer failure mode/cause, and pertinent references. A set of acronym descriptions is provided at the end of the table.

One of the 40 events included in Table A involved a total loss of offsite power (LOSP) condition that occurred at Catawba Unit 2 on 2/06/96. To understand this event, it is useful to understand pertinent features of the Catawba electrical system. Each Catawba reactor unit uses two 50% capacity main transformer banks, each containing three single-phase step-up transformers. A somewhat unique feature at Catawba is that the 50% main transformer banks for each unit also represent the only primary (immediate) sources of offsite power for plant components following a reactor trip. If the two main transformer banks become unavailable, two other alternate (delayed) sources of offsite power can be obtained from the opposite unit via operator alignment of shared 6.9/4.16 KV transformers. The offsite power event at Catawba Unit 2 involved a common cause failure of both main transformer banks during plant operation. Offsite power was lost at Unit 2 for over 5 hours before it was restored via a connection to Unit 1. Loss of main transformers at many other plants would not lead to an automatic LOSP

condition, because power from the offsite grid is normally connected or can be readily routed to the plant via startup, shutdown, or reserve transformers. Catawba does not have such an electrical arrangement. McGuire is another plant that has a main transformer and offsite-to-onsite power supply arrangement similar to Catawba.

Table B summarizes various statistics related to the 40 main transformer failure events. As indicated in this table, 37 of the 40 transformer failure events were grouped in the "reactor trip" category. Of the 3 events not grouped in this category, 2 occurred during plant shutdown conditions, while the third event involved a reactor power cutback. The one event involving total LOSP occurred at Catawba and was previously discussed. Eight of the events resulted in fires, while two events involved explosions. Oil spills occurred in eleven of the events.

Per Table B, there were a total of 19 main transformer failures in the 10-year period from 1980 through 1989, or 1.9 failures per calendar year. In the subsequent 7-year period from 1990 through 1996, there were 21 transformer failures, or 3.0 failures per calendar year. Based on NUREG-1350 data, there was an average of 87 and 110 operating reactors, respectively over these two time intervals. Thus, during the 1980 to 1989 time period, there were about 0.022 transformer failures per reactor per calendar year. In the later 1990-1996 time period, there were 0.027 failures per reactor per calendar year. These data suggest that the main transformer failure rate may have slightly increased in recent years.

Table C provides the total number of main transformer failure events within each of seven separate failure categories. Sixteen of events occurred as a result of internal transformer faults, while an additional six events were related to lightning and/or lightning arrester failures. The one event involving moisture intrusion is the previously discussed Catawba LOSP event.

In each of the two main transformer events involving explosions, it appears that damage was limited to the affected transformer. Fires associated with main transformer fires have damaged some adjacent equipment. For example, during the 7/03/81 North Anna event, fire shorted out the overhead bus bars from a three-phase reserve station transformer (RSS). On the other hand, none of the events related to fires caused a loss of safety-related equipment.

To further explore the potential effect of transformer explosions and fires, the survey of events was expanded beyond main transformers to include other types of outdoor transformers. Table D summarizes the results of this expanded survey. None of these events involved the loss of safety-related equipment. The 11/04/84 event at Duane Arnold appears to have resulted in the largest amount of damage. Equipment damaged from the Duane Arnold event included 161 KV power lines and turbine building siding.

In summary, transformer explosions and fires can cause damage to surrounding equipment and structures, as demonstrated by actual events. At the same time, the historical data suggest that the potential for damage to safety-related equipment is small.

The review of transformer failure data described in the preceding paragraphs was used to provide input data for the SIR public risk calculations listed in Table 1. In using this historical data, the following assumptions and data interpretations were made:

- The data in Table B suggest that main transformer failure events may have been increased in recent years. To account for this potential increase in failure rate, estimation of main transformer failure rates and associated reactor trips were derived from the seven-year period from 1990 through 1996. The frequency of transformer-induced total LOSP was also based on this same time interval. Note that the reactor unit associated with the LOSP event (Catawba 2) was not licensed to operate until 1986.

- A single number (0.2/ry) is used as the LOSP frequency in the Oconee and Grand Gulf PRAs. The PRA documentation does not appear to include a discussion of the derivation or basis for this number. For the purpose of re-prioritization of GSI 107, it was assumed that this LOSP frequency includes not only grid-related LOSP, but also some consideration of LOSP originating on the plant site (plant-centered LOSP). It was further assumed that the offsite power non-recovery data used in the Oconee and Grand Gulf PRA LOSP accident sequence analysis are reasonably representative of non-recovery probabilities that might be expected from LOSP events associated with main transformer failures. Given these assumptions, it was judged appropriate to use the Oconee and Grand Gulf LOSP sequence results in the manner shown in Table 1.

- While the collection of main transformer failure data was based calendar-years, the majority of main transformer failure events occurred during reactor operation (which is to be expected, because main transformers are energized under maximum current conditions only during power operation.) Therefore, the per-reactor-per-calender-year main transformer failure rates generated from the data are also reasonable approximations of per reactor-year failure rates. Therefore, the estimated transformer failure rates can be directly applied to the Oconee and Grand Gulf accident sequence results, which are expressed in a per-reactor-year basis.

The derivations of transformer data used in Table 1 are summarized below:

(1) **Frequency of general transient caused by a main transformer failure (no LOSP)**: from 1990 through 1996, had 19 reactor trips not associated with LOSP; during the same period, had an average of 110 operational reactors; therefore, frequency of reactor trip is (19 events)/(110 reactors x 7 years) = 0.025 events per reactor-yr

(2) **Frequency of LOSP caused by a main transformer failure**: from 1990 to 1996, had 1 LOSP event; during the same period, had an average of 110 operational reactors; therefore, frequency of LOSP is (1 event)/(110 reactors x 7 years) = 0.0013 events per reactor-yr

In applying the above data to the adjusted-case (Step 10 of Table 1), the general transient and LOSP frequencies were reduced by 50% (i.e., general transient frequency reduction = 0.0125/ry and LOSP reduction = 0.00065/ry).

Calculation of Upper and Lower Bounds

Upper and lower bounds on key analysis results such as Total Public Risk Reduction, ΔW (total) were calculated using the FORECAST Code (NUREG/CR-5595, Rev. 1). The parameters used to calculate Total Public Risk Reduction are each entered with a mean value and are characterized by an uncertainty distribution. In most cases, a log-normal distribution was assumed for the values of the input parameters. These distributions are then mathematically combined using convolution integral techniques to generate the mean, upper, and lower values of the parameter.

Table A. Main Transformer Failures Occurring From 1980 Through 1996

Date	Plant	Event Description	Failure Mode/Cause	RX Trip? Total LOSP at Reactor?	Notes and Additional Information	References
2/25/96	Palo Verde	"C" phase of Unit 1 MT bank failed; lighting is suspected as the cause	Possibly lighting	No No	Unit 1 turbine trip and reactor power cutback to 46% (via main turbine bypass system); also caused Unit 3 turbine trip - reason not known	MR 30026, 30037
2/06/96	Catawba	Fault on one phase of both Unit 2 MTs (2A and 2B); this common cause failure of both M[illegible] was apparently cause[illegible]ommon cause failu[illegible]T 22 KV PTs relate[illegible]oisture and contamination of PT resistor bushings; moisture may have been related to melting ice; it appears that damage to MT system was minor; apparently no fire or explosion	Moisture intrusion and contaminants in MT PT resistor bushings	Yes Yes	Each Catawba unit normally receives offsite power through one or both 50% capacity MTs at that unit; alternate offsite power feed must be manually aligned from opposite unit if MTs fail; LOSP to Unit 2 lost for 5 hours 29 minutes, the amount of time taken to cross-connect with Unit 1; train A emergency diesel generator power was immediately available following LOSP	DER 29945 PNO-II-96-006, A, B LER 96-001 NRC Reports 50-413/96-03 and 50-414/96-03
12/18/95	South Texas	MT and UATs lost; pilot wire relay lockout	Pilot wire relay lockout	Yes No		DER 29734.0
8/20/95	Cook	Explosion of MT; there was no fire or damage on site other than to the transformer	Explosion	Not stated No	Not clear if plant operating at time of event; some transformer oil leaked out	DER 29221.0, 29505.0
7/17/95	Sequoyah	Inadvertent signal from sudden pressure relay on Unit 1 "A" phase MT caused "A" phase MT to initiate trip signal	Failure of sudden pressure relay on MT	Yes No	Relay bellows assembly was distended; no other failures or damage	LER 95-010
7/19/94	Beaver Valley	MT failure	Possible fire	Yes No	Unit 1 trip only - Unit 2 not affected; no visible flames, but automatic deluge actuation	DER 27552.0
6/01/94	Beaver Valley	Unit 1 MT fault, subsequent fire; fault caused by insulating bushing failure	Insulating bushing failure, subsequent fire	Yes No	While this was a Unit 1 MT failure, both Unit 1 and 2 tripped	DER 27328.0, 27329.0 LER 94-005
4/05/94	Braidwood	High side phase "B" fault on the "2E" MT; no additional damage to any equipment beyond the MT	Internal fault	Yes No	Unit 2 trip; no visible flames from MT, but automatic fire protection actuation	DER 27046.0 LER 94-003

Date	Plant	Event Description	Failure Mode/Cause	RX Trip? Total LOSP at Reactor?	Notes and Additional Information	References
1/04/92	Clinton	"B" phase MPT failed due to an internal fault; an MPT "sudden pressure trip" resulted	Internal fault	Yes No	The "sudden pressure trip" appears to be associated with the transformer cooling system	DER 22560.0 LER 92-001
8/13/91	Nine Mile Point 2	"B" phase of Unit 2 MST failed due to fault; some oil spilled, but no fire; minimal external physical damage to ancillary and interfacing equipment	Fault related to coil insulation failure	Yes No	Fault caused by failure in insulation of 1 of 3 low voltage coils; MST arrangement at Nine Mile consists of 3 single-phase transformers with an installed spare	DER 21602.0 LER 91-017 NUREG-1455
6/27/91	Fermi	Fire on 1 of 2 MTs - low voltage turret oil bleed cap in contact with isophase bus housing	Fire, oil bleed cap contact with bus housing	Yes No	Manual reactor trip by operators	DER 21276.0
6/24/91	Waterford	MTs "A" and "B" had sudden over pressure signal	Probably caused by lightning	Yes No	Operators manually tripped reactor after runback from 100% to 40% power; STs not affected by lightning strike	DER 21248.0
6/16/91	Salem	A phase 2 MPT initiated flashover on 2 500 KV main generator output breakers as a result of lightning; this subsequently de-energized the No. 1 SPT	Lighting	Yes No	It is not clear if any permanent damage was done	DER 21207.0
4/29/91	Maine Yankee	1 of 2 MTs experienced major failure (fault) and rupture with consequential large oil leakage	Fault	Yes No	Also had fire that appears to have occurred at the junction area where phase leads exit the generator	DER 20911.0
3/13/91	Vermont Yankee	A phase "B" fault on the auto disconnect for the MT tripped 2 breakers between the MT and the switchyard	Auto disconnect failure	Yes No	Large "flash" was noticed, but no fire	DER 20636.0
2/14/91	Hatch	Fire near 1 of 2 MTs	Fire	Yes No	Fire may have occurred at junction area where phase leads exit the generator; MT subsequently ruptured with large leakage of oil; deluge system actuated after fire	DER 20452.0
1/16/91	Peach Bottom	Unit 3 "A" phase MT tripped; oil leaked from transformer relief valve	Transformer cooling system failure	Yes No	Transformer was not damaged	DER 20263.0 LER 91-010

Date	Plant	Event Description	Failure Mode/Cause	RX Trip? Total LOSP at Reactor?	Notes and Additional Information	References
9/22/90	Zion	Unit 2 no. "2W" MT fault and explosion, with a resulting large oil fire; deluge system activated; large quantities of black smoke released and loss of interior turbine building lighting; MT fault most likely caused by nitrogen breakout in MT oil	Explosion and fire; most likely related to fault from nitrogen breakout in oil	Yes No	Unit 2 damage limited to no. "2W" MT; the no. "2E" MT, SAT, and UAT transformers were not damaged; also, no damage to main generator; no apparent effect on Unit 1	DER 19445.0 LER 90-01[illegible]
8/14/90	Palo Verde	Forced cooling lost to "B" phase of Unit 1 MT; cooling failure caused by control power transformer failure; MT cooling fans and pumps were disabled as a result	Loss of forced cooling due to control power transformer failure	Yes No	Per procedures, operator required to unload MT within 30 minutes of cooling loss; manual Unit 1 turbine trip accomplished after 24 minutes, subsequent Unit 1 automatic reactor trip	DER 19129.0 LER 90-006
5/22/90	Surry	Unit 1 "A" MOT fault related to actuation of fire deluge; a small fire resulted from this fault	Fault caused by spurious actuation of fire deluge system; a small fire occurred as a result	Yes No	Unit 1 automatic trip; erratic indications caused operators to trip Unit 2	DER 18550.0
3/28/90	LaSalle	The first phase "B" underslung insulator east of the Unit 1 east and west MPTs failed	Insulator failure	Yes No	Unit 1 operating, Unit 2 defueled prior to event; no damage to MPTs	DER 18080.0
8/11/89	South Texas	Internal fault in 1 of the two Unit 2 MTs; most probable cause of MT fault was failure of high side, phase "A" bushing	Internal fault from bushing failure	Yes No	Major damage to faulted MT; most of MT oil expelled into oil sump; no fire or personnel injuries; plant uses two MTs in parallel per unit; Unit 2 restarted after event with the second undamaged MT - with one MT, unit is capable of operating at approximately 65% power	LER 89-017
7/11/89	Oyster Creek	MT fault that occurred after all 3 lighting arresters blew out	Possibly initiated by lighting (and arrester failure)	Yes No	It appears that LOSP did not occur	DER 16059.0
6/25/89	Oyster Creek	Ground fault in one of the MOTs	Ground fault	Yes No	Internal winding had failed; plant was to have been operated at half load until installation of spare transformer	DER 15952.0 LER 89-016

Date	Plant	Event Description	Failure Mode/Cause	RX Trip? Total LOSP at Reactor?	Notes and Additional Information	References
3/29/89	Point Beach	Unit 2 MT "C" phase faulted due to inadvertent actuation of fire deluge spray	Fault caused by inadvertent actuation of fire deluge	Yes No	Inadvertent actuation of fire deluge occurred during trouble shooting	NSAC-147
11/11/88	Clinton	MPT internal fault on the high voltage side of the transformer	Internal fault	Yes No	It appears that LOSP did not occur; plant has 3 MPTs, one of which is a spare	LER 88-028
8/13/88	Maine Yankee	MOT no. "X1A" faulted (one of 2 MOTs)	Internal fault	Yes No	Electrical "reserve breakers" did not close following trip, causing loss of power to vital buses and RCPs; EDGs provided emergency; however, it does not appear that all LOSP lost to plant	DER 13187.0 NSAC-147
1/10/88	Grand Gulf	"B" MT faulted	Internal fault	Yes No	Cause of fault not provided	DER 11181.0
9/10/87	Wolf Creek	MT 345 KV phase "B" line to switchyard detached itself from lightning arrester (reason for detachment not known)	Connection to lightning arrester lost	Yes No		DER 9940.0
11/30/86	Millstone 1	MT fault due to ground caused by winding insulation failure	Winding insulation failure	Yes No		LER 86-027
6/30/85	Susquehanna	Unit 2 "C" phase MT low voltage bushing failed	Low voltage bushing failure	Yes No	Unit 2 reactor trip; apparently was no additional consequential damage	LER 85-021
2/27/85	Robinson	Failure of MT "C" lightning arrester	Failure of lightning arrester	Yes No	Lighting arrester failure caused generator-to main bank transformer differential generator lockout; it appears that LOSP did not occur	LER 85-009
7/12/84	Indian Point 3	An insulator on the 345 KV side of the MUT failed, resulting in a short-to-ground	Insulator failure	Yes No		NSAC-147
12/05/82	North Anna	Phase "B" transformer of the Unit 1 MT failed; cause believed to be related to oil contamination; significant damage to other electrical components, including those connected to phase bus and main generator	Unknown; fire	Yes No	About 1,500 gallons of oil released; oil contained in concrete basin; north side of the generator neutral enclosure was blown out - a fire was also created in this enclosure, but only minimal damage resulted	IE NOTICE 82-53 UCID-20053

Date	Plant	Event Description	Failure Mode/Cause	RX Trip? Total LOSP at Reactor?	Notes and Additional Information	References
11/16/82	North Anna	Phase "C" transformer of the Unit 1 MT failed; failure may have been related to release of previously dissolved nitrogen gas from oil	Unknown	No (N/A) No	Failure occurred while Unit 1 was being heated up following refueling outage; oil sprayed into adjacent area from small hole blown in transformer; oil contained in concrete basin, no subsequent fire; plant in hot shutdown at time of event	IE NOTICE 82-53 UCID-20053
8/22/82	North Anna	Phase "B" transformer of the Unit 2 MT failed due to electrical insulator bushing failure; cause - mechanical failure of bushing due to excessive shipments and handling	Insulator bushing failure	Yes No	Hot transformer oil sprayed around failed unit, fire protection system activated; oil sprayed bus bars of RSST "C"	IE NOTICE 82-53 UCID-20053
7/25/81	North Anna	Phase "C" transformer of the Unit 2 MT failed due to high voltage to ground fault (incipient fault)	Ground fault	No (N/A) No	Failure occurred during pre-operational testing; transformer tank ruptured with loss of cooling oil; plant shutdown at time of event; no fire	IE NOTICE 82-53 UCID-20053
7/03/81	North Anna	Phase "B" transformer of the Unit 2 MT bank failed from high-voltage bushing to ground failure	High-voltage bushing to ground failure; fire	Yes No	Failure due to improper storage of bushings prior to use; transformer box and 1 oil pump discharge pipe ruptured; the oil ignited, and resultant fire shorted out the overhead bus bars from a RSST	IE NOTICE 82-53 UCID-20053
6/19/81	North Anna	Phase "C" transformer of the Unit 2 MT bank failed from high voltage bushing to ground failure	High-voltage bushing to ground failure	Yes No	Failure due to improper storage of bushings prior to use	IE NOTICE 82-53 UCID-20053
11/29/80	North Anna	Phase "A" transformer of the Unit 2 MT bank failed due to winding to ground failure; faulty winding temperature indications may have been contributing factor	Winding to ground failure	Yes No	Human error responsible for over-fill of oil	IE NOTICE 82-53 UCID-20053

Date	Plant	Event Description	Failure Mode/Cause	RX Trip? Total LOSP at Reactor?	Notes and Additional Information	References

Acronyms:

DER - Daily Event Report - also called an Event Report
LER - Licensee Event Report
MR - Morning Report - also called a Daily Report
PNO - Preliminary Notice of Event or Unusual Occurrence

MOT - Main Output Transformer
MPT - Main Power Transformer
MST - Main Step-up Transformer
MT - Main Transformer
MUT - Main Unit Transformer
PT - Potential Transformer
RSST - Reserve Station Service Transformer
SAT - Station Auxiliary Transformer
ST - Startup Transformer (sometimes also referred to as shutdown or reserve auxiliary transformer)
UAT - Unit Auxiliary Transformer

Notes: (1) Table does not distinguish between automatic and manual reactor trips; the method by which reactor trip occurred is not important because any reactor trip is considered a transient initiating event in a PRA analysis

Table B. Summary of Main Transformer Failure Data From 1980 Through 1996

Year	Main Transformer Failure Events	Reactor Trips (includes manual trips)	Total LOSP	Fires	Explosions	Oil Spills
1990 Through 1996						
1996	2	1	1			
1995	3	3 (see note 1)			1	1
1994	3	3		2		
1993	0	0				
1992	1	1				
1991	8	8		2		4
1990	4	4		2 (see note 2)	1 (see note 2)	
Subtotal 1990-1996	21	20	1	6	2	5
1980 Through 1989						
1989	4	4				1
1988	3	3				
1987	1	1				
1986	1	1				
1985	2	2				
1984	1	1				
1983	0	0				
1982	3	2		1		3
1981	3	2		1		2
1980	1	1				
Subtotal 1980-1989	19	17	0	2	0	6
1980 Through 1996						
Total 1980-1996	40	37	1	8	2	11

Notes: (1) Of the 3 transformer events in 1995, 2 definitely resulted in a reactor trip; it is not clear if the third event also resulted in a reactor trip; this third event was conservatively counted as a reactor trip (2) One of the 1990 events involved both a fire and explosion

Table C. Main Transformer Failures Grouped By Failure Category

Failure Category	Number of Transformer Failures
Internal fault	16
Spurious actuation of fire deluge system	2
Lightning and/or lightning arrester failure	6
Cooling system failure	2
Insulator failure	2
Moisture intrusion	1
Other/unknown	11
Total	40

Table D. Explosion and Fire-Related Events Occurring in Other Types of Outdoor Transformers From 1980 Through 1996

Date	Plant	Event Description	Failure Mode/Cause	RX Trip? Total LOSP at Reactor?	Notes and Additional Information	References
10/05/96	Sequoyah	A PT exploded in the 500 KV switchyard, causing a loss of switchyard bus no. 1; oil from faulted PT sprayed onto gravel and ignited; switchyard relays and circuit breakers operated properly to clear fault	Explosion and fire	No No	Both units continued to operate at full power; shrapnel from explosion damaged the 500 KV to 160 KV intertie transformer, and other switchyard components, including insulators	PNO-II-96-069
10/21/95	Diablo Canyon	Fire in UAT; workers incorrectly tried to connect a "ground buggy" (to shunt electrical phases to ground)	Fire; human error caused incorrect shunt connection	No (N/A) Yes	Affected Unit 1 only; this unit was apparently shutdown at time of event; LOSP not recovered for several hours	DER 29491.0 MR 4-96-0027
2/25/94	Oconee	Insulator on SWYDIT spare transformer caused fire	Fire caused by failure of attached insulator	No No	Failed SWYDIT was a spare - none of 3 units affected by failure	DER 26846.0
7/04/92	Peach Bottom	No. 1 ST transformer exploded; fire also occurred at time of explosion; subsequent oil spill was confined within transformer dike	Explosion and fire	Yes No	Not clear which unit(s) were tripped; appears that only partial LOSP occurred; other (no. 2 ST) used to provide power to safety buses	DER 23791.0, 23792.0, 23793.0
11/27/90	Zion	Unit 2 SAT deluge system automatically activated, possible due to SAT fire; this SAT provides Unit 1 reserve power	Possible fire	No No	SAT lost while one of Unit 1 EDGs out of service for maintenance - Unit 1 shutdown due to Tech Spec requirements	DER 19952.0
8/25/90	Waterford	Transformer fire caused by lightning	Lightning-induced fire	Yes Yes	Specific transformer type not identified, but appears to be a SWYDT - transformer is located in 500 KV switchyard; LOSP was momentary	DER 19200.0
7/06/88	Palo Verde	UAT explosion, with subsequent fire; cause of event related to 13.8 KV ground fault and subsequent failure of protective breakers to immediately open	Explosion and fire	Yes No	Fire followed explosion; Unit 1 was tripped	DER 12727.0 IE NOTICE 89-64

Date	Plant	Event Description	Failure Mode/Cause	RX Trip? Total LOSP at Reactor?	Notes and Additional Information	References
4/13/86	Peach Bottom	An explosion and fire occurred in a SWYDT that ties the 220 KV grid to the site 500 KV ring bus; loss of this transformer caused 1 of 2 STs to become de-energized	Explosion and fire	Not stated No	A fast transfer of the 4 KV emergency buses was successfully made to an alternate startup source; offsite power for safety buses available at all times; Unit 2 was at 72% power, Unit 3 in cold shutdown	NSAC-147 LER 86-010
11/04/84	Duane Arnold	UAT failed catastrophically; resulting fireball reached as high as the 161 KV lines; these 161 KV lines and primary bushings on ST received heavy carbon deposits; a fire wall between the UAT and ST limited damage to the ST	Fireball, fire	Yes No	Deluge systems for both UAT and ST initiated; metal siding in the area of the fire was damaged such that fires were reported both at the transformer and in the turbine building where the siding was damaged	NSAC-147 LER 84-040

Acronyms:

DER - Daily Event Report - also called an Event Report
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MR - Morning Report - also called a Daily Report
PNO - Preliminary Notice of Event or Unusual Occurrence

MT - Main Transformer
PT - Potential Transformer
SAT - Station Auxiliary Transformer
SWYDIT - Switchyard Intertie Transformer
SWYDT - Switchyard Transformer
ST - Startup Transformer (sometimes also referred to as shutdown or reserve auxiliary transformer)
UAT - Unit Auxiliary Transformer

Notes: (1) Table does not distinguish between automatic and manual reactor trips; the method by which reactor trip occurred is not important because any reactor trip is considered a transient initiating event in a PRA analysis

Attachment 1 to Table 3

Discounted vs Undiscounted Costs

Summary costs are shown in the ISSUE SUMMARY WORK SHEET and in Table 3 on a non-discounted basis, i.e., costs or savings projected to recur throughout the remaining life of the nuclear plants are treated as though they were occurring immediately. This approach gives equal weight to immediate expenditures/savings and those which would be spread out over the remaining plant lifetime. The results shown in the ISSUE SUMMARY WORK SHEET (undiscounted case) and in Table 3 indicate that the projected future savings due to avoided transformer repair costs and the associated avoided plant down time and replacement energy costs more than offset the expenditures by licensees to review their transformer-related procedures, provide enhanced training, and perform additional maintenance.

Economic evaluations typically allow discounting of future expenditures to present the results on a present-worth basis, and discounting is called for by NRC's Regulatory Analysis Guidelines (NUREG/BR-0058, Rev. 2). OMB guidelines suggest that a 7% discount rate be applied for most analyses of this type. Given the 7% discount rate and the average nuclear plant remaining life of 22 years, discounting reduces the present worth of future expenditures and savings to about one-third to one-half of their non-discounted values. The impact of discounting is to shift the Total Industry Costs (non-accident) from an overall savings of $4.1 million to a net cost of $0.1 million. Bottom line estimates are as follows:

Cost Element	Undiscounted, 10^6 1996$	Discounted, 10^6 1996$
Industry Costs:		
a) SIR Implementation:	4.53	4.53
b) SIR Operation/Maintenance:	(-)8.6	(-)4.4
Sum, a + b:	(-)4.07	0.12
Accident Avoidance:	(-)1.0	(-)0.33
Sum of Above:	(-)5.07	(-)0.21
NRC Costs:		
SIR Development:	0.10	0.10
SIR Implementation:	0.56	0.56
SIR Operation/Maintenance Review:	2.1	0.69
Sum of Above:	2.27	1.35

Negative sign (-) indicates a savings

Parameter Uncertainty

Table E summarizes the mean values and associated uncertainties for key parameters utilized in the analysis. The uncertainties or error factors were used to estimate the upper and lower bounds for costs and radiation exposures.

Table E. Key Parameter Values and Associated Uncertainty

Parameter	Mean Value	Units	Apply to ?	Uncertainty or Error Factor
Public Exposure				
Delta CDF-PWR	1.77E-7	1/yr	all PWRs	5
Delta CDF-BWR	0.711E-7	1/yr	all BWRs	5
Affected Public Risk, PWR	118.5	p-rem/ry	all PWRs	5
Affected Public Risk, BWR	212.7	p-rem/ry	all BWRs	5
Licensee Costs Per Plant				
Costs (Savings) from Accident Avoidance				
Severe Accident Cleanup & Decontamination Costs	1.69E9	$/event	all	2
Severe Accident Long Term Shutdown Replacement Energy Cost - PWR	310,000	$/day	all PWRs	2
Severe Accident Long Term Shutdown Replacement Energy Cost - BWR	250,000	$/day	all BWRs	2
Severe Accident Occupational Exposure - short term - long term	1,000 20,000	P-rem/ event	all	10 3
Industry Implementation Costs				
- Review Requirements	15,890	$/plant	all	1.5
- Procedural Changes	6,671	$/plant	all	1.5
- Staff Training	7,524	$/plant	all	1.5
- Physical Modifications &QA	99,375	$/plant	10%	1.5
- Additional Procedures	6,780	$/ plant	10%	1.5
Industry Operation & Maintenance Costs				
- Procedure review	454	$/ry	all	1.3
- Training update	2,843	$/ry	all	1.3
- Additional Maintenance	2,270	$/ry	10%	1.3
Improved Reliability				
Avoided Transformer Repair or Replacement Cost	3,050	$/event	all	2
Avoided Downtime Cost due to Reduced Transformer Failures	4,026	$/ry	all	2
NRC Costs				
SIR Development	102,614	$		1.25
Implementation	5,111	$/plant	all	1.25
Recurring Operational Costs	852	$/ry	all	1.25

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