Applicant’s Environmental Report – Operating License Renewal Stage

Arkansas Nuclear One - Unit 1

Introduction

Set forth below is Entergy Operations' Environmental Report-Operating License Renewal Stage for Arkansas Nuclear One, Unit 1. This report was prepared in conjunction with Entergy Operations' application to the U. S. Nuclear Regulatory Commission to renew the operating license for ANO-1. In compliance with applicable NRC requirements, this ER analyzes potential environmental impacts associated with renewal of the ANO-1 license. It is designed to assist the NRC staff with the preparation of the ANO-1 specific Supplemental Environmental Impact Statement that is required for license renewal. The content of the ER complies with the requirements of 10CFR Part 51, as augmented by the NRC's "Generic Environmental Impact Statement for License Renewal of Nuclear Plants" (NUREG-1437).

Specifically, the ANO-1 ER complies with 10CFR54.23, which requires license renewal applicants to submit a supplement to the ER that complies with requirements of Subpart A of 10CFR Part 51. This report also addresses the more detailed requirements of NRC environmental regulations in 10CFR51.45 and 10CFR51.53, as well as the underlying intent of the National Environmental Policy Act, 42 U.S.C. § 4321 *et seq*. For major federal actions, the NEPA requires federal agencies to prepare a detailed statement that addresses significant environmental impacts, adverse environmental effects that cannot be avoided should the proposal be implemented, alternatives to the proposed action, and any irreversible and irretrievable commitments of resources associated with implementation of the proposed action. The information responsive to these requirements is set forth in the following sections of the ER:

Section 1.0: Purpose and Need for the Proposed Action
Section 2.0: Site and Environmental Interfaces
Section 3.0: Proposed Action
Section 4.0: Environmental Consequences of the Proposed Action
Section 5.0: Alternatives Considered
Section 6.0: Comparison of Impacts
Section 7.0: Status of Compliance

Based upon the evaluations discussed in the ER, Entergy Operations concludes that the environmental impacts associated with the renewal of the ANO-1 operating license are small. The environmental impacts from continued operation of ANO-1 are similar to those experienced during the original operating term and as evaluated in the Final Environmental Statement [Reference 1] issued in February 1973. No major plant refurbishment activities have been identified as necessary to support the continued operation of ANO-1 beyond the end of the existing operating license. Although normal plant maintenance activities may later be performed for economic and operational reasons, no significant environmental impacts associated with such activities are expected. Major refurbishment and plant maintenance activities typically receive an environmental review per ANO procedures during the planning stage for the activity.

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ACRONYMS and ABBREVIATIONS

ALWR	Advanced Light Water Reactor
ADEQ	Arkansas Department of Environmental Quality
ADH	Arkansas Department of Health
AGFC	Arkansas Game and Fish Commission
ANHC	Arkansas Natural Heritage Commission
ANO	Arkansas Nuclear One
B&W	Babcock and Wilcox
BTA	Best Technology Available
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
DOE	Department of Energy
EA	Environmental Assessment
EIA	Energy Information Act
EIS	Environmental Impact Statement
EPA	U. S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ER	Environmental Report-Operating License Renewal Stage
FES	Final Environmental Statement
FWPCA	Federal Water Pollution Control Act
GEIS	Generic Environmental Impact Statement
GIS	Geographic Information System
IPE	Individual Plant Examination
ISFSI	Independent Spent Fuel Storage Installation
LOCA	Loss of Coolant Accident
MACCS	Melcor Accident Consequences Code System

MSW	Municipal Solid Waste
NEPA	National Environmental Policy Act
NESC	National Electrical Safety Code
NOx	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NRC	U. S. Nuclear Regulatory Commission
NRR	(Office Of) Nuclear Reactor Regulation
NUREG	Nuclear Report Category
O&M	Operation and Maintenance
PV	Photovoltaic Cells
PSA	Probabilistic Safety Assessment
PWR	Pressurized Water Reactor
$PM_{2.5}$	Particulate Matter (nominal size of <2.5 microns)
RCRA	Resource Conservation and Recovery Act
SAMA	Severe Accident Mitigation Alternatives
SAMDA	Severe Accident Mitigation Design Alternative
SCR	Selective Catalytic Reduction
SHPO	State Historic Preservation Office
SO_2	Sulfur Dioxide
SRP	(NRC) Standard Review Plan
USC	United States Code

UNITS

cfs	cubic feet per second
fps	feet per second
ft	feet
ft^3	cubic feet
gpm	gallons per minute
ha	hectares
hr	hour
kg	kilograms
km	kilometer
kV	kilovolt
kW	kilowatt
mA	milliamps
MW	megawatts
MWd/MTU	megawatt day/metric ton uranium
MW(e)	megawatts, electric
MW(t)	megawatts, thermal
m	meters
m^3	cubic meters
mA	millamperes
°C	degrees celsius
°F	degrees fahrenheit

1.0 PURPOSE AND NEED FOR THE PROPOSED ACTION

For license renewal, the NRC has adopted the following definition of purpose and need: "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." This is from Section 1.3 of the NRC Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants, NUREG-1437 [Reference 2].

Nuclear power plants are licensed by the NRC to operate for up to 40 years, and the licenses may be renewed [10CFR50.51] for periods up to 20 years. 10CFR54.17(c) states that "[a]n application for a renewed license may not be submitted to the Commission earlier than 20 years before the expiration of the operating license currently in effect." The proposed action will extend the ANO-1 operating license for a period of 20 years beyond the current operating license expiration date. The current operating license for ANO-1 expires at midnight on May 20, 2014 and would be renewed to expire at midnight on May 20, 2034.

2.0 SITE AND ENVIRONMENTAL INTERFACES

ANO is owned by Entergy Arkansas, Inc. and operated by Entergy Operations, Inc., both subsidiaries of Entergy Corporation. The site is located in southwestern Pope County, Arkansas, about 57 miles northwest of Little Rock, Arkansas, and 68 miles east of Fort Smith, Arkansas, on a peninsula formed by Lake Dardanelle as shown on Figure 2.1-1. Lake Dardanelle is part of the "Multiple-Purpose Improvement Plan for the Arkansas River" and includes the Arkansas River and the former Illinois Bayou. The town of Russellville, Arkansas is about six miles east-southeast of the site and the town of London, Arkansas is about two miles northwest of the site.

The construction of ANO-1 began after receipt of a construction permit on December 6, 1968, and extended until initial criticality on August 6, 1974. The impacts to the environment from the construction, operation, and decommissioning were evaluated prior to receipt of a construction permit, further investigated during the construction phase, and study results summarized in the Final Environmental Statement for ANO-1 issued in February 1973 [Reference 1].

2.1 General Site Environment

The ANO site is centrally situated on a peninsula about two miles wide and two miles long, which extends into Lake Dardanelle. On three sides, the site is surrounded by lake water. Generally, the site peninsula is at an elevation of about 400 feet, but some areas are above 500 feet. Ground surface within the plant site property line is predominantly meadow. Outside of the property line, forests cover the majority of the peninsula, with pasture, cropland, and residential development each contributing significant proportions of the remaining land-use. A breakdown of the land cover classes, acreage and percentage on the ANO site is shown in Table 2.1-1, with Figure 2.1-2 showing approximate locations on the ANO site.

To the north of the site, the land mass gradually ascends to 1,000 feet altitude at a distance of about 15 miles in the Boston Mountains. The maximum height of the Boston Mountains (2,700 feet) is 41 miles north-northwest of the site. Generally, the Arkansas River follows along the base of the Boston Mountains. The higher portions of the mountains are located west-northwest to east-northeast of the site.

To the south and west of the site, across the Arkansas River and Lake Dardanelle, is a range of hills. Directly south is Mount Nebo, elevation 1,880 feet, at a distance of about eight miles. Further to the west and about 25 miles from the site is Magazine Mountain at 3,042 feet altitude, the highest point in the state. To the east, and extending to the south, the land area is moderately level, interspersed with rolling hills frequently covered with woods.

The site is characterized by excellent natural drainage. Surface runoff from the site is collected in storm water drains, the intake canal, and the emergency cooling pond where it is discharged to its natural destination, Lake Dardanelle. The average annual rainfall at the site is approximately 49 inches [Reference 1].

The region (50-mile radius) surrounding ANO was classified by the GEIS as having a low population, based on the population near the site, and the proximity and size of nearby cities [GEIS, Appendix C, Table C.2]. Nearby towns include the cities of Russellville [Figure 2.1-1] and London. Areas along Lake Dardanelle are developed with permanent residences, along with campgrounds, hiking trails, boat launch areas, and marinas. There are no permanent residences within the 0.65-mile (1.0 km) radius (exclusion zone) of ANO.

Table 2.1-1, ANO Land Cover Classification Areas

Land Cover Classes	Land Cover Class Acreage	Land Cover Class Percentage
Mixed Hardwoods	575	49.4%
Mixed Hardwoods/Pine	39	3.4%
Pine	11	0.9%
Wetland	5	0.4%
Shrub/Sapling	55	4.7%
Disturbed or w/o Cover	449	38.6%
Open water	30	2.6%
Total Land Area	1,164	100.0%

Note: On Figure 2.1-2, mixed hardwoods, pine, and shrub/saplings are grouped as "Mixed Pine-Hardwood", disturbed or without cover is shown as "Early Successional", and wetland and open water are grouped as "water".

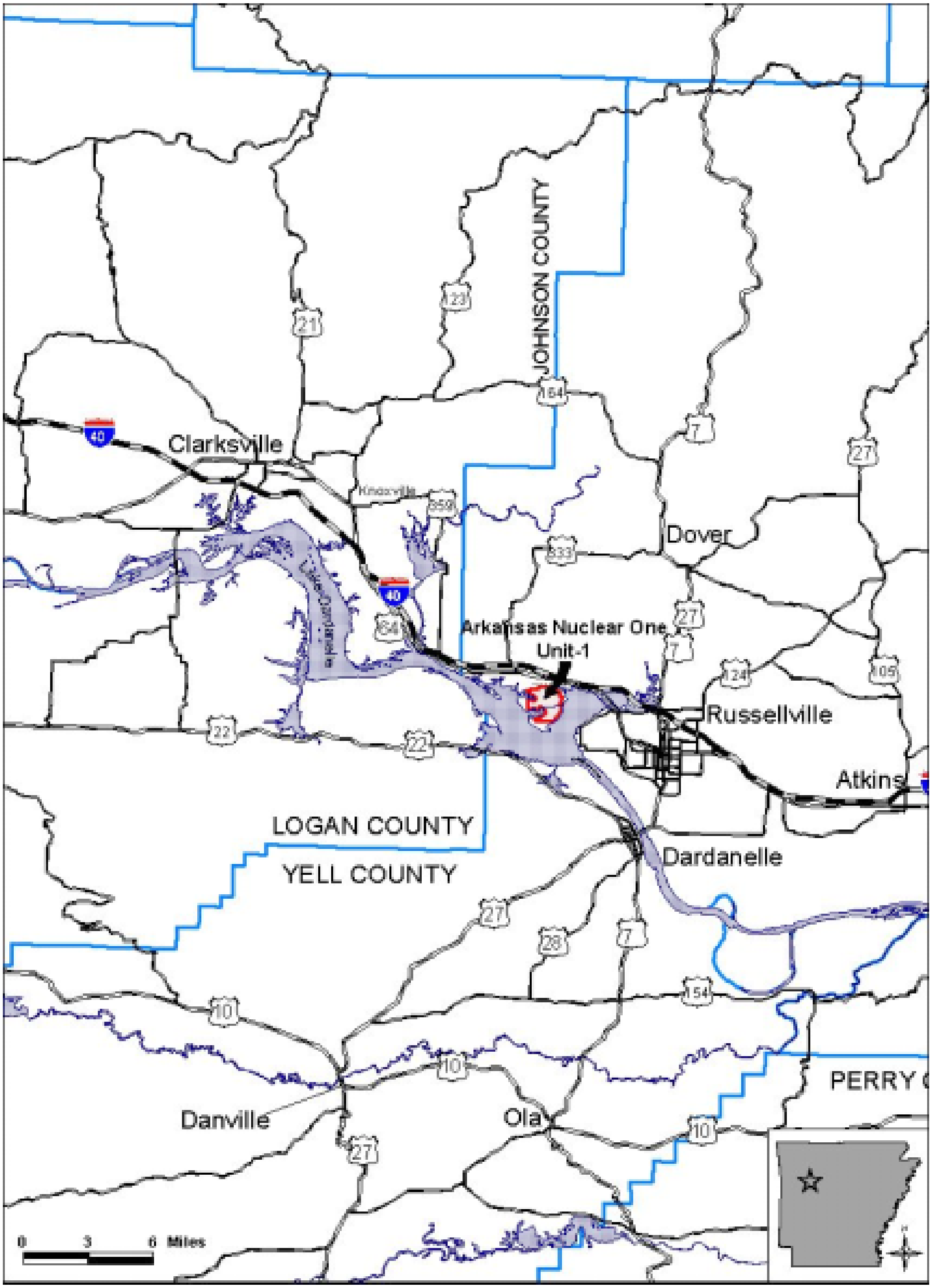

Figure 2.1-1, General Area for Arkansas Nuclear One

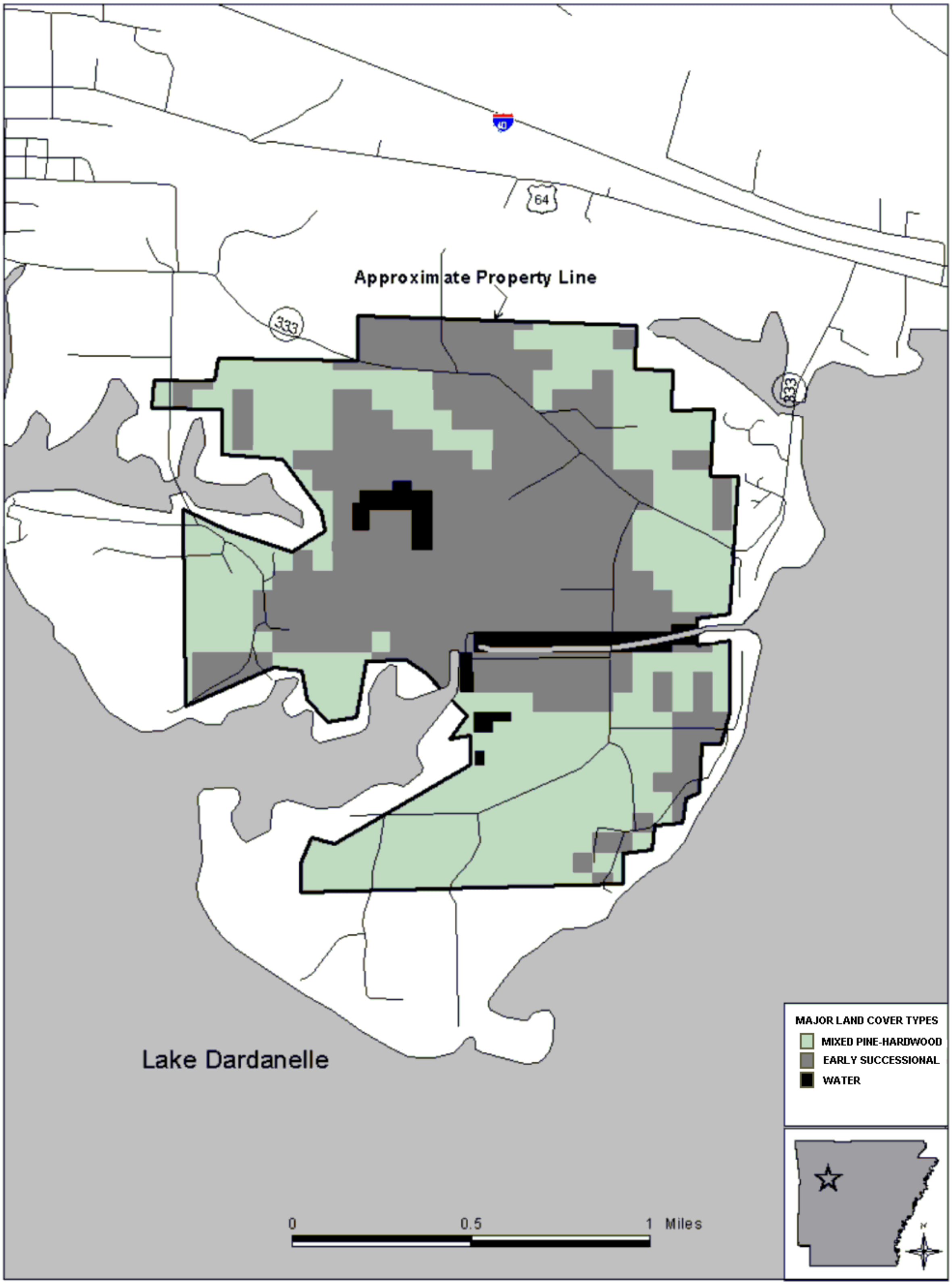

Figure 2.1-2, ANO Land Cover Areas

2.2 Lake Dardanelle

Lake Dardanelle [Figure 2.2-1], which is a part of the Arkansas River, is 50 miles long. It is over 60 feet deep at its lower end and has a surface area of approximately 37,000 acres, with an average depth of approximately 10 feet. The average flow into the lake is 35,620 cfs from a drainage area of 153,703 square miles. Lake Dardanelle has a storage capacity of 486,000 acre-feet, with a normal pool elevation of 338 feet, controlled downstream by the Dardanelle Lock and Dam.

Besides serving the needs of ANO-1, Lake Dardanelle serves a variety of other uses. The lake has been designated as suitable for the propagation of fish/wildlife, primary and secondary contact recreation, and public and industrial water supplies. The water quality of Lake Dardanelle is monitored routinely by the ADEQ. Recent studies have shown no evidence of degraded water quality and that all designated uses for the lake are being fully supported [References 3, 4, and 5].

Water-based recreation activities are a focal point of interest, with abundant opportunities for boating and fishing. In addition, camping, picnicking, sightseeing, photography, and nature study areas are available to visitors at strategic locations around the shoreline. The commercial fishing industry has grown in this area as compared to previous years. The species composition and general health of the fish in Lake Dardanelle are normal for the region.

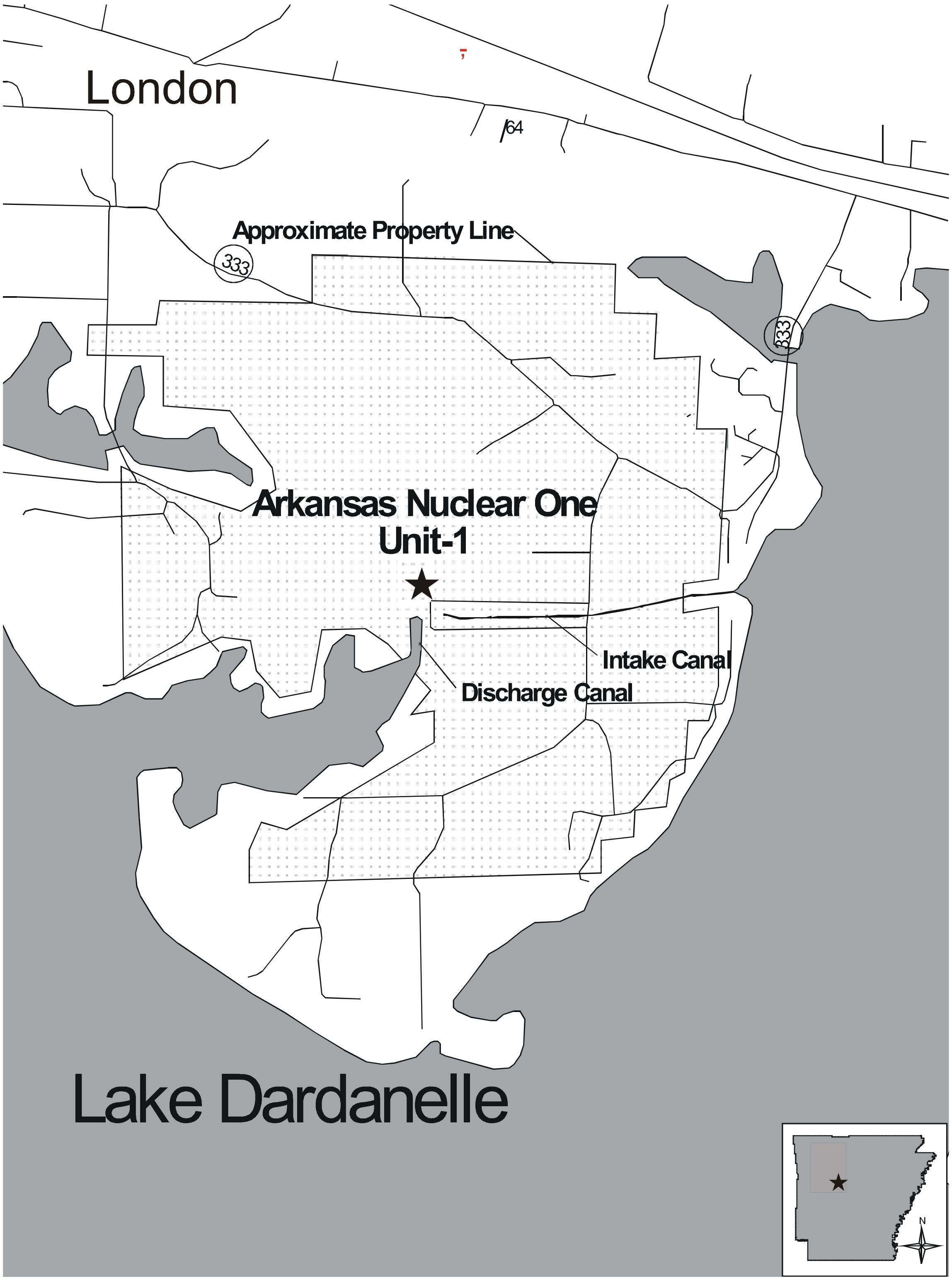

Figure 2.2-1, Lake Dardanelle - Cooling Water Source for ANO–1

2.3 ANO Plant Description

The ANO site has two pressurized water reactors, with nuclear steam supply systems manufactured by Babcock and Wilcox (ANO-1) and Combustion Engineering (ANO-2). ANO-1 was licensed by the NRC and began commercial operation in 1974. ANO-1 has a thermal rating of 2568 MW(t) and a maximum dependable electrical generation capacity of 836 net MW(e) [See Table 2.3-1].

ANO-1 consists of a reactor building, an auxiliary building, and a common turbine building shared with ANO-2. The reactor and nuclear steam supply system for ANO-1 are contained within the reactor building. Mechanical and electrical systems required for the safe operation of ANO-1 are primarily located in the auxiliary and reactor buildings. Figure 2.3-1 shows the general features of the ANO site. Figure 2.3-2 shows the 0.65-mile radius exclusion zone. No residences are permitted within this exclusion zone.

The ANO-1 condensers utilize once-through cooling; whereas, the ANO-2 condensers utilize closed-cycle cooling. Lake Dardanelle serves as the cooling water source for ANO-1 [Figure 2.2-1]. ANO-1 utilizes approximately 1,700 cfs of cooling water to condense steam during normal operation. The cooling water from the Illinois Bayou arm of Lake Dardanelle flows through a 4400-foot long canal to the intake structure. After flowing through the main condenser, the cooling water is then discharged to a 520-foot long canal prior to entering Lake Dardanelle [Reference 1]. A water flow diagram is provided in Attachment A.

The main features of the intake structure include bar grates, traveling screens, and four circulating water pumps. The bar grates have three-inch openings and prevent large debris from entering the intake structure. Inside the bar grates, cooling water passes through 3/8-inch mesh, vertical, traveling screens. The maximum water velocity through the traveling screens is approximately 2.2 fps. Debris that accumulates on the screens is removed through periodic cleaning. After passing through the traveling screens, the cooling water enters the circulating water pumps which have a rated capacity of approximately 191,000 gpm each.

The emergency cooling pond serves as a source of cooling water in the unlikely event of loss of Lake Dardanelle water inventory. The pond has a surface area of 14 acres and a normal depth of 6 feet for a total water inventory of 84 acre-feet.

Entergy Operations operates an independent spent fuel storage installation in accordance with 10CFR Part 72 at ANO. The ISFSI is not within the scope of 10CFR Part 54 since it governs the issuance of renewed operating licenses for nuclear power plants and 10CFR Part 72 governs the ISFSI licenses. Radiological monitoring associated with the ISFSI is included in the site effluent release program.

Table 2.3-1, ANO-1 Site Information

Location:	Pope County, Arkansas 10 km (6 miles) WNW of Russellville latitude 35º-18’-36”N; longitude 93°–13’-53”W Licensee: Entergy Arkansas, Inc.

Unit Information	Unit 1
Docket Number	50-313
Construction Permit	1968
Operating License	1974
Commercial Operation	1974
License Expiration	2014
Licensed Thermal Power [MW(t)]	2568
Design Electrical Rating [net MW(e)]	850
Capability [MW(e)]	836
Type of Reactor	PWR
Nuclear Steam Supply System Vendor	B&W

Cooling Water System

Type: once-through
Source: Lake Dardanelle
Typical Source Temperature Range: 4-28°C (40-83°F)
Design Condenser Temperature Rise: 8.3°C (15°F)
Intake Structure: 1341 m (4400 ft) canal
Discharge Structure: 160 m (520 ft) canal

Site Information

Total Area: 471 ha (1164 acres)
Exclusion Distance: 1.05 km (0.65 mile) radius
Low Population Zone: 6.44 km (4.00 mile) radius
Nearest Major City: Little Rock; 1990 population: 175,795
Site Topography: flat
Surrounding Area Topography: hilly to mountainous
Land Use within 8 km (5 miles): wooded
Nearby Features: The nearest town is London 3 km (2 miles) NW. The size of Lake Dardanelle is 15,000 ha (37,000 acres) and is part of the Arkansas River. The Missouri Pacific Railroad and U. S. Highway I-40 are just N of the site.
Population within an 80-km (50-mile) radius:

1990	2000	2010	2020	2030
200,000	274,037	295,803	312,158	322,991

Sources are:
Reference 1 ANO-1 FES, Reference 2 GEIS, and
U.S. Census Bureau 1990

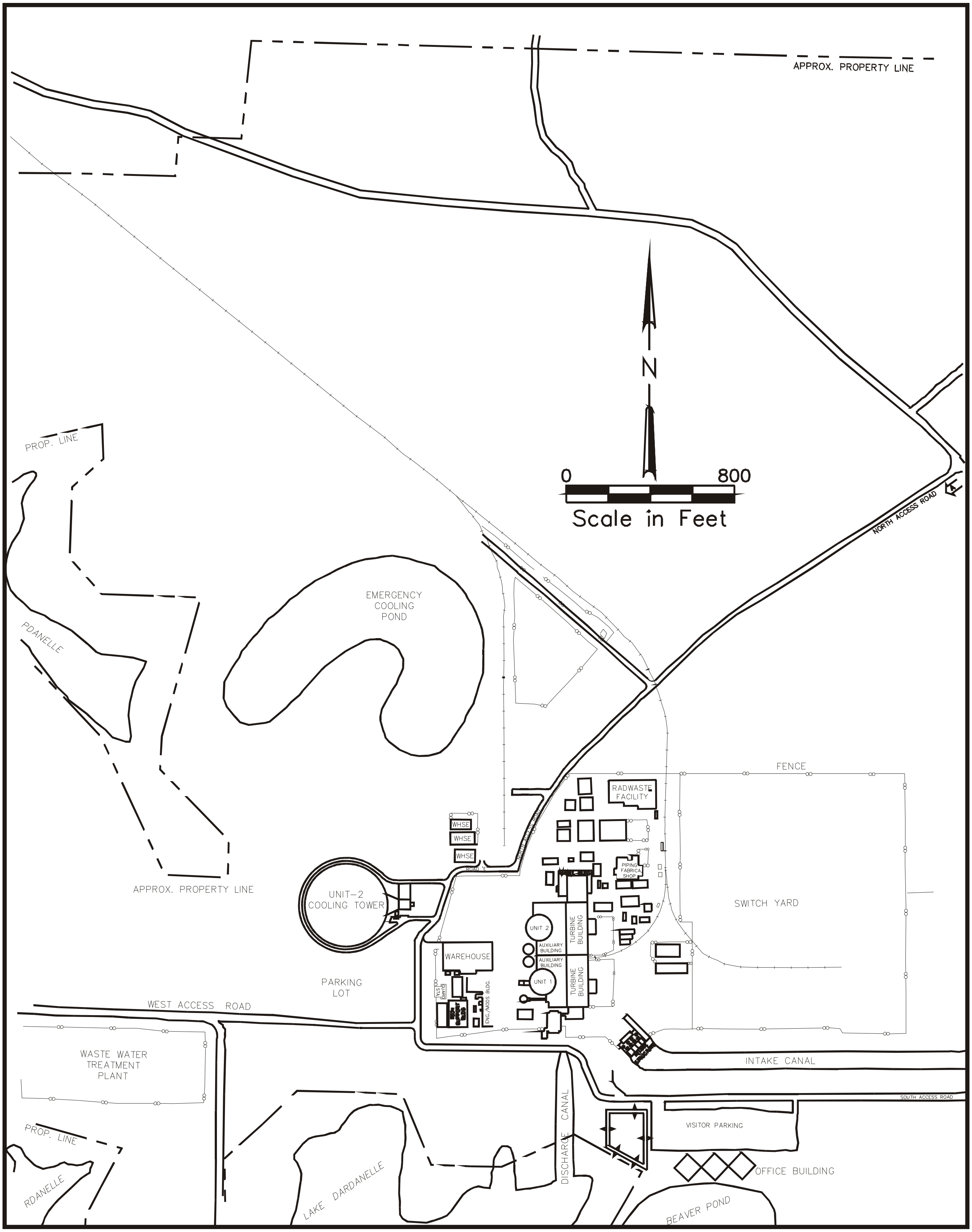

Figure 2.3-1, Arkansas Nuclear One Site – General Features

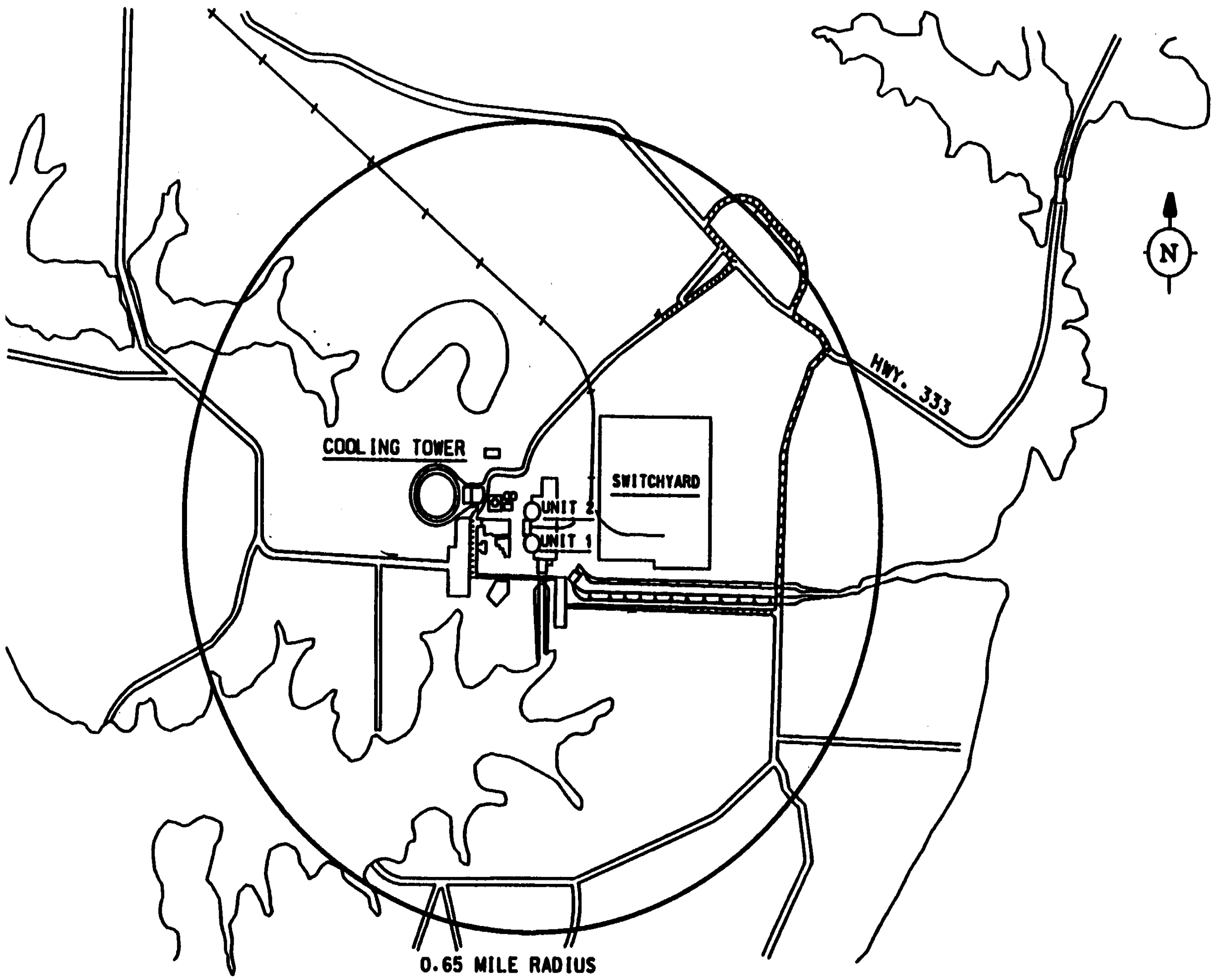

Figure 2.3-2, Arkansas Nuclear One –Exclusion Zone

2.4 Resident Population Estimates

Resident population estimates within 50 miles (80 km) of ANO for the years 2000, 2005, 2010, 2015, 2020, 2025 and 2030 are shown in Tables 2.4-1 through 2.4-7. The computer program SECPOP90 was used to process block-level 1990 census data to prepare population estimates for the region surrounding ANO. [Reference 6]. The 50-mile (80 km) radius area around the plant was divided into sixteen directions that are equivalent to a standard navigational compass rosette. This rosette was further divided into fifteen "inner" radial rings, each with sixteen azimuthal sections. The rings chosen were based on requirements for use in the SAMA analyses. These were grouped for this report into 10-mile (16 km) bands.

The SECPOP90 census data file used for the ANO evaluation contains a record for the location (geometric centroid coordinates) and the population of each census block (6,660,337 records) in the continental U.S. It is a binary file sorted primarily by descending longitude (west to east) and secondarily by descending latitude (north to south). The westernmost point in the census data file that lies on or to the east of the western longitude boundary of the geometric rosette was first found. For that data point and each subsequent data point read from the file, it was determined if the point lies between the north and south latitudinal boundaries for the 50-mile radii area. When a point was found to lie between the established boundaries, the distance of that point from the site is calculated to determine if in fact the point lies within the outer limits of the rosette grid. If the point met the distance criteria, it was then processed to determine the exact grid element in which it lies based on its radial distance and direction from the site. The population associated with that data point is then added to the population of that grid section. This process produced the 1990 population estimate for each rosette section.

The countywide 1998 population estimates, which were the most complete and current estimates available, were then utilized to update the 1990 estimates to 1998. For each rosette section, the fraction of its area in each county was estimated. These fractions were then used to calculate a county-area weighted population growth factor (1998 county population divided by 1990 county population) for the section. The 1990 section population was then multiplied by this growth factor to produce the 1998 population estimate for that section.

Since countywide projections were unavailable, the statewide 2000-2025 Bureau of the Census data was then used to project the future rosette section populations for the years 2000 to 2030 in five-year steps. For each step, a statewide growth factor was calculated by dividing the state population projection for that year by the 1998 state population estimate. A value for the year 2030 population was found by extrapolation. The mean change in population from 2015 to 2020 and from 2020 to 2025 was used to extrapolate the change for 2025 to 2030. This change was then added to the year 2025 data to prepare the year 2030 population projection. The section population projection for this step year is then calculated by multiplying the 1998 section population by the state growth factor.

Table 2.4-1, Resident Population Estimates, 2000

Sector	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	Total
N	1,503	1,030	355	352	1,850	5,090
NNE	2,221	3,859	269	380	822	7,551
NE	14,775	4,630	1,929	363	1,320	23,017
ENE	11,507	2,987	2,023	1,849	4,848	23,214
E	4,506	5,772	9,009	5,091	21,611	45,989
ESE	1,899	639	4,794	3,294	38,275	48,901
SE	841	894	1,305	1,825	3,311	8,176
SSE	1,118	701	332	4,640	12,334	19,125
S	473	2,037	172	781	9,257	12,720
SSW	606	1,341	504	484	1,898	4,833
SW	391	3,026	617	615	600	5,249
WSW	315	1,142	881	1,198	1,372	4,908
W	58	237	5,062	8,033	6,521	19,911
WNW	713	1,781	4,455	9,993	4,078	21,020
NW	322	2,295	10,073	1,838	1,330	15,858
NNW	1,321	3,333	2,377	748	696	8,475
Total	42,569	35,704	44,157	41,484	110,123	274,037

Table 2.4-2, Resident Population Estimates, 2005

Sector	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	Total
N	1,571	1,077	371	368	1,934	5,321
NNE	2,322	4,033	281	397	859	7,892
NE	15,443	4,839	2,016	379	1,379	24,056
ENE	12,027	3,122	2,114	1,932	5,068	24,263
E	4,710	6,033	9,416	5,321	22,589	48,069
ESE	1,985	667	5,011	3,443	40,007	51,113
SE	879	934	1,364	1,908	3,460	8,545
SSE	1,169	733	347	4,850	12,892	19,991
S	494	2,129	179	816	9,676	13,294
SSW	633	1,401	527	506	1,984	5,051
SW	409	3,163	645	643	627	5,487
WSW	329	1,194	921	1,252	1,434	5,130
W	60	248	5,291	8,396	6,816	20,811
WNW	745	1,861	4,656	10,445	4,263	21,970
NW	336	2,399	10,528	1,922	1,390	16,575
NNW	1,381	3,484	2,484	782	727	8,858
Total	44,493	37,317	46,151	43,360	115,105	286,420

Table 2.4-3, Resident Population Estimates, 2010

Sector	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	Total
N	1,622	1,112	383	380	1,997	5,494
NNE	2,398	4,165	291	410	887	8,151
NE	15,948	4,998	2,082	392	1,425	24,845
ENE	12,421	3,224	2,184	1,995	5,234	25,058
E	4,864	6,231	9,724	5,495	23,328	49,642
ESE	2,050	689	5,175	3,556	41,316	52,786
SE	907	965	1,409	1,970	3,574	8,825
SSE	1,207	757	358	5,009	13,314	20,645
S	510	2,198	185	843	9,993	13,729
SSW	654	1,447	544	523	2,049	5,217
SW	422	3,266	666	664	648	5,666
WSW	340	1,233	951	1,293	1,481	5,298
W	62	256	5,465	8,671	7,040	21,494
WNW	769	1,922	4,809	10,787	4,402	22,689
NW	347	2,477	10,873	1,984	1,435	17,116
NNW	1,426	3,598	2,565	808	751	9,148
Total	45,947	38,538	47,664	44,780	118,874	295,803

Table 2.4-4, Resident Population Estimates, 2015

Sector	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	Total
N	1,669	1,144	394	391	2,055	5,653
NNE	2,467	4,285	299	422	913	8,386
NE	16,409	5,142	2,142	403	1,466	25,562
ENE	12,779	3,318	2,247	2,053	5,385	25,782
E	5,005	6,410	10,005	5,654	24,002	51,076
ESE	2,109	709	5,325	3,659	42,509	54,311
SE	934	993	1,450	2,027	3,677	9,081
SSE	1,242	779	368	5,153	13,698	21,240
S	525	2,262	191	868	10,281	14,127
SSW	673	1,489	560	538	2,108	5,368
SW	434	3,361	685	683	666	5,829
WSW	350	1,269	978	1,330	1,524	5,451
W	64	263	5,622	8,921	7,243	22,113
WNW	791	1,978	4,948	11,099	4,529	23,345
NW	357	2,549	11,187	2,042	1,477	17,612
NNW	1,467	3,702	2,639	831	772	9,411
Total	47,275	39,653	49,040	46,074	122,305	304,347

Table 2.4-5, Resident Population Estimates, 2020

Sector	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	Total
N	1,712	1,174	404	401	2,108	5,799
NNE	2,530	4,395	307	433	936	8,601
NE	16,830	5,274	2,197	413	1,503	26,217
ENE	13,107	3,403	2,304	2,106	5,523	26,443
E	5,133	6,575	10,262	5,799	24,618	52,387
ESE	2,164	727	5,461	3,752	43,600	55,704
SE	958	1,018	1,487	2,079	3,771	9,313
SSE	1,274	799	378	5,285	14,050	21,786
S	539	2,320	196	890	10,545	14,490
SSW	690	1,527	574	551	2,162	5,504
SW	445	3,447	703	700	684	5,979
WSW	359	1,301	1,003	1,365	1,563	5,591
W	66	270	5,767	9,150	7,429	22,682
WNW	812	2,029	5,075	11,384	4,645	23,945
NW	366	2,614	11,474	2,094	1,515	18,063
NNW	1,505	3,797	2,707	853	792	9,654
Total	48,490	40,670	50,299	47,255	125,444	312,158

Table 2.4-6, Resident Population Estimates, 2025

Sector	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	Total
N	1,745	1,196	412	408	2,149	5,910
NNE	2,579	4,480	313	441	954	8,767
NE	17,156	5,376	2,240	421	1,532	26,725
ENE	13,361	3,469	2,349	2,146	5,630	26,955
E	5,232	6,702	10,460	5,911	25,094	53,399
ESE	2,205	742	5,567	3,825	44,444	56,783
SE	976	1,038	1,516	2,120	3,844	9,494
SSE	1,299	814	385	5,388	14,322	22,208
S	549	2,365	199	907	10,749	14,769
SSW	703	1,557	585	562	2,204	5,611
SW	454	3,514	716	714	697	6,095
WSW	366	1,326	1,023	1,391	1,593	5,699
W	67	275	5,878	9,327	7,572	23,119
WNW	827	2,068	5,173	11,604	4,735	24,407
NW	373	2,665	11,696	2,135	1,544	18,413
NNW	1,534	3,871	2,760	869	808	9,842
Total	49,426	41,458	51,272	48,169	127,871	318,196

Table 2.4-7, Resident Population Estimates, 2030

Sector	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	Total
N	1,771	1,215	418	415	2,181	6,000
NNE	2,618	4,548	317	448	969	8,900
NE	17,414	5,457	2,273	428	1,555	27,127
ENE	13,562	3,521	2,384	2,179	5,715	27,361
E	5,311	6,803	10,618	6,000	25,472	54,204
ESE	2,239	753	5,651	3,883	45,113	57,639
SE	991	1,053	1,539	2,151	3,902	9,636
SSE	1,318	827	391	5,469	14,538	22,543
S	557	2,400	202	921	10,911	14,991
SSW	714	1,580	594	571	2,237	5,696
SW	461	3,567	727	725	707	6,187
WSW	371	1,346	1,038	1,412	1,617	5,784
W	68	279	5,967	9,468	7,686	23,468
WNW	840	2,099	5,251	11,779	4,807	24,776
NW	379	2,705	11,872	2,167	1,567	18,690
NNW	1,557	3,929	2,801	882	820	9,989
Total	50,171	42,082	52,043	48,898	129,797	322,991

3.0 PROPOSED ACTION

3.1 Description of the Proposed Action

The proposed action is renewal of the existing ANO-1 operating license for an additional 20 years beyond the expiration of the current operating license. The facility operating license for ANO-1 currently expires on midnight May 20, 2014 and would be renewed to expire at midnight on May 20, 2034.

There are no changes related to license renewal with respect to the operations of ANO-1 that would directly affect the environment or plant effluents that affect the environment during the period of license extension. The environmental impacts from continued operation of ANO-1 are similar to those experienced during the original operating term and evaluated in the Final Environmental Statement [Reference 1].

3.2 Plant Modifications or Refurbishments which are Required for License Renewal

10CFR51.53(c)(2) requires that a license renewal applicant's ER contain: "a description of the proposed action, including the applicant's plans to modify the facility or its administrative control procedures as described in accordance with Section 54.21 of this chapter. This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment."

The objective of the review required by 10CFR54.21 is to determine whether the detrimental effects of plant aging could preclude certain ANO-1 systems, structures, and components from performing, in accordance with the manner in which they were initially designed, during the additional 20 years of operation requested in the license renewal application. The evaluation of structures and components as required by 10CFR54.21 has been completed.[1] This evaluation did not identify the need for refurbishment of structures or components. In addition, no other modifications or refurbishment activities related to license renewal have been identified as necessary.

1 A full description of this review is contained in ANO-1 License Renewal Application [Reference 7].

3.3 Programs for Managing Aging

The programs for managing aging of systems and equipment at ANO-1 are described in the ANO-1 License Renewal Application [Reference 7]. The evaluation of structures and components required by 10CFR54.21 identified some new inspection activities necessary to continue operation of ANO-1 during the additional 20 years beyond the initial license term. These activities are described in the ANO-1 License Renewal Application [Reference 7]. The additional inspection activities are consistent with normal plant component inspections, and therefore, are not expected to cause any significant environmental impact. The majority of the aging management programs are either existing programs or modest modifications of existing programs.

3.4 Employment

The non-outage work force at ANO consists of approximately 1313 persons. There are 1145 Entergy employees normally on-site. The remaining 168 persons are baseline contractor employees. Table 3.4-1 shows employee residences by county and city. The GEIS estimated that an additional 60 employees would be necessary for operation during the period of extended operation. Since there will not be significant new aging management programs added at ANO, Entergy Operations believes that it will be able to manage the necessary programs with existing staff. Therefore, Entergy Operations has no plans to add non-outage employees to support plant operations during the period of the extended license.

Refueling and maintenance outages typically have durations of approximately 30 days. Depending on the scope of these outages, an additional 1,300 to 1,400 workers are typically on-site. The number of workers required on-site for normal plant outages during the period of the renewed license is expected to be consistent with the numbers of additional workers used for past outages at ANO.

Table 3.4-1 Arkansas Employee Residence Information (ANO), August 1999

County and City	Entergy Employees
CONWAY COUNTY	11
Hattieville	1
Morrilton	7
Springfield	3
CRAWFORD COUNTY	1
Alma	1
FAULKNER COUNTY	19
Conway	19
FRANKLIN COUNTY	2
Alix	1
Ozark	1
GARLAND COUNTY	1
Hot Springs	1
JOHNSON COUNTY	82
Clarksville	31
Coal Hill	4
Hagerville	1
Hartman	4
Knoxville	15
Lamar	27
LOGAN COUNTY	8
New Blaine	1
Scranton	5
Subiaco	2
LONOKE COUNTY	1
Austin	1
PERRY COUNTY	1
Bigelow	1
POPE COUNTY	938
Atkins	33
Dover	89
Hector	8
London	62
Pelsor	1
Pottsville	30
Russellville	715

Table 3.4-1, Arkansas Employee Residence Information (ANO), August 1999 (continued)

County and City	Entergy Employees
PULASKI COUNTY	6
Little Rock	3
Maumelle	1
North Little Rock	1
Sherwood	1
YELL COUNTY	75
Belleville	4
Casa	3
Centerville	1
Danville	4
Dardanelle	55
Delaware	2
Havana	1
Ola	3
Plainview	1
Waveland	1
Total	1145

Table 3.4-1 Arkansas Employee Residence Information (ANO), August 1999 (continued)

County and City	Baseline Contractor Employees
CONWAY COUNTY	5
Jerusalem	1
Morrilton	4
FRANKLIN COUNTY	1
Ozark	1
JOHNSON COUNTY	25
Clarksville	10
Hartman	5
Knoxville	3
Lamar	7
PERRY COUNTY	1
Perryville	1
POPE COUNTY	104
Atkins	9
Dover	16
Hector	3
London	7
Pelsor	1
Pottsville	5
Russellville	63
SEARCY COUNTY	2
Witt Springs	1
Marshall	1
YELL COUNTY	30
Belleville	1
Buckville	1
Danville	4
Dardanelle	16
Havana	4
Ola	2
Plainview	2
Total	168

4.0 ENVIRONMENTAL CONSEQUENCES OF THE PROPOSED ACTION

4.1 Discussion of GEIS Categories for Environmental Issues

The Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants, NUREG-1437, summarizes the approach and findings of a systematic inquiry into the potential environmental consequences of renewing the licenses and operating individual nuclear power plants for an additional 20 years. The GEIS assesses 92 environmental issues relevant to license renewal. The GEIS assessment of these issues was used to assign the Categories to the 92 environmental issues listed in 10CFR Part 51, Subpart A, Appendix B, Table B-1. In turn, Table B-1 was used to develop the requirements for the environmental issues listed in 10CFR51.53(c)(3)(ii). The GEIS assigned most environmental issues[2] one of the three following significance levels:

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 important attributes of the resource.

Large: Environmental effects are clearly noticeable and are sufficient to destabilize important attributes of the resource.

4.1.1 Category 1 Issues

Category 1 issues are defined as those environmental issues whose analysis in the GEIS has shown that:

- 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 characteristics;

- a single significance level (i.e., small, moderate, or large) has been assigned to the impacts (except for collective off-site radiological impacts from the fuel cycle and from high-level waste and spent fuel); and

[2] Of the 92 environmental issues evaluated in the GEIS and Addendum 1, 69 were designated as Category 1 and 21 were designated as Category 2. Two environmental issues were assigned as Category NA (Not Applicable). These issues are electromagnetic fields (chronic effects) and environmental justice. Footnotes to Table 9.1, in the GEIS provide details on the category definition for these issues.

- 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 not to be sufficiently beneficial to warrant implementation.

Sixty-nine of the issues evaluated in the GEIS and Addendum 1 [Reference 35] were found to be Category 1. These issues are identified in Appendix B to Subpart A of Part 51 as not requiring additional plant-specific analysis. 10CFR51.53(c)(3)(i) provides that the environmental report for the operating license renewal stage need not contain analyses of the environmental impacts of the license renewal issues identified as Category 1. Entergy Operations adopts the generic conclusions of the GEIS and Addendum 1.

4.1.2 Category 2 Issues

For the Category 2 issues, the NRC analysis presented in the GEIS has shown that one or more of the Category 1 criteria cannot be met, and therefore, additional plant-specific review is required. Twenty-one of the issues evaluated in the GEIS and Addendum 1 were found to meet the Category 2 criteria. The NRC's findings on the environmental impact of these issues are summarized in 10CFR Part 51, Subpart A, Appendix B, Table B-1. The ER must contain an analysis 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 (plant-specific) issues in Appendix B to Subpart A of 10CFR Part 51. These 21 issues have been incorporated into 12 specific analytical requirements that are listed in 10CFR51.53(c)(3)(ii).

4.1.3 Table B-1, Appendix B to Subpart A and 10CFR51.53(c)(3)(ii) Issues

Table 4.1-1, of the ER, was developed to show the relationship of the Table B-1 Category 2 issues to the 10CFR51.53(c)(3)(ii) requirements. Table B-1, Subpart A, Appendix B lists 21 Category 2 issues. The Category 2 issues listed in Table B-1 can be referenced to the 12 analytical requirements defined in 10CFR51.53(c)(3)(ii). For example, 10CFR51.53(c)(3)(ii)(I) requires that an assessment of the impact of the proposed action on housing availability, land-use, public schools, and public water supplies be performed. Table B-1 lists five socioeconomic Category 2 issues that can be addressed in the same analysis required by 10CFR51.53(c)(3)(ii)(I). Table 4.1-1 lists the issue, the findings from Table B-1, and the applicable 10CFR51.53(c)(3)(ii) requirements. The issues were grouped by broader topics, such as surface water quality, aquatic ecology, etc.

4.1.4 Review of 10CFR51.53(c)(3)(ii) Issues

The review and analysis for the 10CFR51.53(c)(3)(ii) issues are found in Sections 4.2 through 4.13. The issues can be placed into one of three categories, which are discussed below. Table 4.1-2 provides a summary of the results for the issues listed in 10CFR51.53(c)(3)(ii).

4.1.4.1 10CFR51.53(c)(3)(ii) Issues not Applicable to ANO-1

No analysis is provided for issues that are not applicable to ANO-1. The basis for Entergy Operations' determination that a certain issue is not applicable is set forth in the specific section of the ER. Three of the issues listed in 10CFR51.53(c)(3)(ii) are not applicable to the ANO site and one other is not applicable to ANO-1 specifically as shown in Table 4.1-2. A discussion of the four non-applicable issues (water use conflicts, ground-water use conflicts, ground-water quality, and vehicle exhaust emissions) is provided in subsequent sections of the ER.

4.1.4.2 10CFR51.53(c)(3)(ii) Issues Applicable to ANO-1

The format for the Section 4.0 discussion of the 10CFR51.53(c)(3)(ii) issues applicable to ANO-1 is described below:

- Requirement - The requirement from 10CFR51.53(c)(3)(ii) is restated.

- Findings from Table B-1, Appendix B to Subpart A - The Finding(s) for the issue from Table B-1 - Summary of Findings on NEPA Issues for License Renewal of Nuclear Power Plants, Subpart A, is presented. Several of the issues in 10CFR51.53(c)(3)(ii) have more than one issue from Table B-1 associated with that issue.

- Background - An excerpt from the applicable section of the GEIS is provided as background. The specific section of the GEIS is referenced for the convenience of the reader.

- Analysis of Environmental Impact - An analysis of the environmental impact as required by 10CFR51.53(c)(3)(ii) is provided, taking into account information provided in the GEIS, Appendix B to Subpart A of Part 51, as well as ANO-1 specific information.

- Consideration of Alternatives for Reducing Adverse Impacts - The alternatives to reduce or avoid adverse environmental effects are assessed as required by 10CFR51.45(c) and 10CFR51.53(c)(3)(iii).

4.1.4.3 10CFR51.53(c)(3)(ii) Issues Applicable to ANO-1 Related to Refurbishment

As discussed in Section 3.2, Plant Modifications or Refurbishments Required for License Renewal, the evaluation of structures and components required by 10CFR54.21 did not identify any major plant refurbishment activities[4] or modifications necessary to support the continued operation of ANO-1 beyond the end of the existing operating license. Accordingly, there are no identified refurbishment activities or modifications that would affect the environment or plant effluents. Therefore, further analysis of these issues is not required.

4 GEIS, Appendix B, Table B.2 lists major refurbishment/replacement activities associated with license renewal.

Table 4.1-1, Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

SURFACE WATER QUALITY, HYDROLOGY, AND USE (for all plants)

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	SMALL OR MODERATE. 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. See 10CFR51.53(c)(3)(ii)(A).	[10CFR51.53(c)(3)(ii)(A)] 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 $3.15x10^{12}$ ft^3/year ($9x10^{10}$ 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.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

AQUATIC ECOLOGY (for plants with once-through and cooling pond heat dissipation systems)

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Entrainment of fish and shellfish in early life stages	SMALL, MODERATE, OR LARGE. The impacts of entrainment are small 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. See 10CFR51.53(c)(3)(ii)(B).	[10CFR51.53(c)(3)(ii)(B)] 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 and, if necessary, a 316(a) variance in accordance with 40CFR 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 and impingement and entrainment.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

AQUATIC ECOLOGY (for plants with once-through and cooling pond heat dissipation systems) (continued)

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Impingement of fish and shellfish	SMALL, MODERATE, OR LARGE. 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. See 10CFR51.53(c)(3)(ii)(B).	[10CFR51.53(c)(3)(ii)(B)] 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 and, if necessary, a 316(a) variance in accordance with 40CFR 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 and impingement and entrainment.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

AQUATIC ECOLOGY (for plants with once-through and cooling pond heat dissipation systems) (continued)

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Heat shock	SMALL, MODERATE, OR LARGE. 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. See 10CFR51.53(c)(3)(ii)(B).	[10CFR51.53(c)(3)(ii)(B)] 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 and, if necessary, a 316(a) variance in accordance with 40CFR Part 125, or equivalent state permits and supporting documentation. If the applicant can not provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock and impingement and entrainment.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

GROUNDWATER USE AND QUALITY

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Ground-water use conflicts (potable and service water, and dewatering; plants that use >100 gpm)	SMALL, MODERATE, OR LARGE. Plants that use more than 100 gpm may cause ground-water use conflicts with nearby ground-water users. See 10CFR51.53(c)(3)(ii)(C).	[10CFR51.53(c)(3)(ii)(C)] If the applicant's plant uses Ranney wells or pumps more than 100 gallons (total on-site) of ground-water per minute, an assessment of the impact of the proposed action on ground-water use must be provided.
Ground-water use conflicts (plants using cooling towers withdrawing make-up water from a small river)	SMALL, MODERATE, OR LARGE. 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 ground-water or upstream surface water users come on line before the time of license renewal. See 10CFR51.53(c)(3)(ii)(A).	[10CFR51.53(c)(3)(ii)(A)] 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.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

GROUNDWATER USE AND QUALITY (continued)

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Ground-water use conflicts (Ranney wells)	SMALL, MODERATE, OR LARGE. 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. See 10CFR51.53(c)(3)(ii)(C).	[10CFR51.53(c)(3)(ii)(C)] If the applicant's plant uses Ranney wells or pumps more than 100 gallons (total on-site) of ground-water per minute, an assessment of the impact of the proposed action on ground-water use must be provided.
Ground-water quality degradation (cooling ponds at inland sites)	SMALL, MODERATE, OR LARGE. 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. See 10CFR51.53(c)(3)(ii)(D).	[10CFR51.53(c)(3)(ii)(D)] 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 ground-water quality must be provided.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

TERRESTRIAL RESOURCES

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Refurbishment impacts	SMALL, MODERATE, OR LARGE. 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. See 10CFR51.53(c)(3)(ii)(E).	[10CFR51.53(c)(3)(ii)(E)] All license renewal applicants shall assess the impact of refurbishment and other license-renewal-related construction activities on important plant and animal habitats. Additionally, the applicant shall assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act.

THREATENED OR ENDANGERED SPECIES (for all plants)

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Threatened or endangered species	SMALL, MODERATE, OR LARGE. 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. See 10CFR51.53(c)(3)(ii)(E).	[10CFR51.53(c)(3)(ii)(E)] All license renewal applicants shall assess the impact of refurbishment and other license-renewal-related construction activities on important plant and animal habitats. Additionally, the applicant shall assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

AIR QUALITY

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Air quality during refurbishment (nonattainment and maintenance areas)	SMALL, MODERATE, OR LARGE. 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. See 10CFR51.53(c)(3)(ii)(F).	[10CFR51.53(c)(3)(ii)(F)] 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.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

HUMAN HEALTH

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	SMALL, MODERATE, OR LARGE. 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. See 10CFR51.53(c)(3)(ii)(G).	[10CFR51.53(c)(3)(ii)(G)] If the applicant's plant uses a cooling pond, lake, or canal or discharges into a river having an annual average flow rate 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.
Electromagnetic fields, acute effects (electric shock)	SMALL, MODERATE, OR LARGE. 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. See 10CFR51.53(c)(3)(ii)(H).	[10CFR51.53(c)(3)(ii)(H)] If the applicant's transmission lines that were constructed for the specific purpose of connecting the plant[3] to the transmission system do not meet the recommendations of the National Electric Safety Code for preventing electric shock from induced currents, an assessment of the impact of the proposed action on the potential shock hazard from the transmission lines must be provided.

[3] The plant is defined as the nuclear reactors, steam-electric systems, intakes, discharges, and all other on-station facilities involved in the production of electricity. Transmission lines and other off-station facilities are not part of the plant. (NUREG-1555, SRP-ER, Introduction Chapter, Definitions, February 1999)

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

SOCIOECONOMICS

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Housing impacts	SMALL, MODERATE, OR LARGE. 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 in areas with growth control measures that limit housing development. See 10CFR51.53(c)(3)(ii)(I).	[10CFR51.53(c)(3)(ii)(I)] An assessment of the impact of the proposed action on housing availability, land-use, and public schools (impacts from refurbishment activities only) within the vicinity of the plant must be provided. Additionally, the applicant shall provide an assessment of the impact of population increases attributable to the proposed project on the public water supply.
Public services: public utilities	SMALL OR MODERATE. An increased problem with water shortages at some sites may lead to impacts of moderate significance on public water supply availability. See 10CFR51.53(c)(3)(ii)(I).	[10CFR51.53(c)(3)(ii)(I)] An assessment of the impact of the proposed action on housing availability, land-use, and public schools (impacts from refurbishment activities only) within the vicinity of the plant must be provided. Additionally, the applicant shall provide an assessment of the impact of population increases attributable to the proposed project on the public water supply.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

SOCIOECONOMICS (continued)

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Public services, education (refurbishment)	SMALL, MODERATE, OR LARGE. Most sites would experience impacts of small significance but larger impacts are possible depending on site- and project-specific factors. See 10CFR51.53(c)(3)(ii)(I).	[10CFR51.53(c)(3)(ii)(I)] An assessment of the impact of the proposed action on housing availability, land-use, and public schools (impacts from refurbishment activities only) within the vicinity of the plant must be provided. Additionally, the applicant shall provide an assessment of the impact of population increases attributable to the proposed project on the public water supply.
Offsite land use (refurbishment)	SMALL OR MODERATE. Impacts may be of moderate significance at plants in low population areas. See 10CFR51.53(c)(3)(ii)(I).	[10CFR51.53(c)(3)(ii)(I)] An assessment of the impact of the proposed action on housing availability, land-use, and public schools (impacts from refurbishment activities only) within the vicinity of the plant must be provided. Additionally, the applicant shall provide an assessment of the impact of population increases attributable to the proposed project on the public water supply.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

SOCIOECONOMICS (continued)

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Offsite land-use (license renewal term)	SMALL, MODERATE, OR LARGE. Significant changes in land-use may be associated with population and tax revenue changes resulting from license renewal. See 10CFR51.53(c)(3)(ii)(I).	[10CFR51.53(c)(3)(ii)(I)] An assessment of the impact of the proposed action on housing availability, land-use, and public schools (impacts from refurbishment activities only) within the vicinity of the plant must be provided. Additionally, the applicant shall provide an assessment of the impact of population increases attributable to the proposed project on the public water supply.
Public services, Transportation	SMALL, MODERATE, OR LARGE. Transportation impacts (level of service) of highway traffic generated during plant refurbishment and during the term of the renewed license are generally expected to be of small significance. However, the increase in traffic associated with the additional workers and the local road and traffic control conditions may lead to impacts of moderate or large significance at some sites. See 10CFR51.53(c)(3)(ii)(J).	[10CFR51.53(c)(3)(ii)(J)] All applicants shall 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.

Table 4.1-1 (Continued) Comparison of Appendix B to Subpart A, Table B-1 Issues to 10CFR51.53(c)(3)(ii) Issues

SOCIOECONOMICS (continued)

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Historic and archaeological resources	SMALL, MODERATE, OR LARGE. 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. See 10CFR51.53(c)(3)(ii)(K).	[10CFR51.53(c)(3)(ii)(K)] All applicants shall assess whether any historic or archaeological properties will be affected by the proposed project.

POSTULATED ACCIDENTS

Issue	Findings from Table B-1	10CFR51.53(c)(3)(ii) Reference
Severe accidents	SMALL. 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. See 10CFR51.53(c)(3)(ii)(L).	[10CFR51.53(c)(3)(ii)(L)] 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 environmental assessment, a consideration of alternatives to mitigate severe accidents must be provided.

Table 4.1-2, Summary of Results for Analyses of Category 2 Issues

Category 2 Issue **10CFR51.53(c)(3)(ii)Requirement**	**Summary of Analysis Results**
Water use conflicts (Plants with cooling towers and cooling ponds) 10CFR51.53(c)(3)(ii)(A)	Not applicable to ANO–1 (ANO-1 utilizes once-through cooling).
Entrainment, impingement, and heat shock of fish and shellfish 10CFR51.53(c)(3)(ii)(B)	Impact is small. State and federal agencies concluded that ANO has had no significant adverse impacts on Lake Dardanelle.
Ground-water use conflicts (Ranney Wells or pumps more than 100 gallons per minute of groundwater) 10CFR51.53(c)(3)(ii)(C)	Not applicable to ANO (There are no wells located on the ANO site).
Ground-water quality (Plants with cooling ponds) 10CFR51.53(c)(3)(ii)(D)	Not applicable to ANO (ANO-1 utilizes once-through cooling).
Refurbishment impacts on important plant and animal habitats, and threatened or endangered species 10CFR51.53(c)(3)(ii)(E)	Impact is small. No major refurbishment activities identified. Six federal species listed due to potential geographic range. No state species listed.
Vehicle Exhaust Emissions 10CFR51.53(c)(3)(ii)(F)	Not applicable to ANO (ANO is not located in or near non-attainment or maintenance area).
Microbiological (thermophilic) organisms 10CFR51.53(c)(3)(ii)(G)	Impact is small. No concerns identified by ANO or state agency.
Electrical shock from induced currents 10CFR51.53(c)(3)(ii)(H)	Impact is small. Potential for electric shock is not significant.
Housing, land-use, public schools and public water supply impacts 10CFR51.53(c)(3)(ii)(I)	Impact is small. Site-specific reviews showed impacts to be less than those evaluated in the GEIS.
Local transportation impacts 10CFR51.53(c)(3)(ii)(J)	Impact is small. Site-specific reviews showed impacts to be less than those evaluated in the GEIS.
Historic and archaeological properties 10CFR51.53(c)(3)(ii)(K)	Impact is small. No significant properties identified.
Severe accident mitigation alternatives 10CFR51.53(c)(3)(ii)(L)	No impact from continued operation.

4.2 Water Use Conflicts (Plants with Cooling Towers and Cooling Ponds)

4.2.1 Requirement [10CFR51.53(c)(3)(ii)(A)]

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 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.

4.2.2 Analysis of Environmental Impact

ANO-1 uses a once-through cooling system;[5] therefore, this issue is not applicable to ANO-1 and analysis is not required.

4.3 Entrainment, impingement, and heat shock of fish and shellfish

4.3.1 Requirement [10CFR51.53(c)(3)(ii)(B)]

If the applicant's plant utilizes once-through cooling[5] or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations and, if necessary, a 316(a) variance in accordance with 40CFR 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 and impingement and entrainment.

4.3.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"The impacts of entrainment are small 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. See 10CFR51.53(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. See 10CFR51.53(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. See 10CFR51.53(c)(3)(ii)(B)."

[5] In a once-through cooling system, circulating water for condenser cooling is drawn from an adjacent body of water, such as a lake or river, passed through the condenser tubes, and returned at a higher temperature to the adjacent body of water. The waste heat is dissipated to the atmosphere, mainly by evaporation from the water body and, to a much smaller extent, by conduction, convection, and thermal radiation loss [Reference 2].

4.3.3 GEIS Background

The impacts of fish and shellfish entrainment are small at many plants, but they may be moderate or even large at a few plants with once-through cooling systems. Further, ongoing restoration efforts may increase the numbers of fish susceptible to intake effects during the license renewal period, so that entrainment studies conducted in support of the original license may no longer be valid. For these reasons, the entrainment of fish and shellfish is a Category 2 issue for plants with once-through cooling [Reference 2 GEIS Section 4.2.2.1.2].

Aquatic organisms that are drawn into the intake with the cooling water and are too large to pass through the debris screens may be impinged against the screens. Mortality of fish that are impinged is high at many plants because impinged organisms are eventually suffocated by being held against the screen mesh or are abraded, which can result in fatal infection. Impingement can affect large numbers of fish and invertebrates (crabs, shrimp, jellyfish, etc.). As with entrainment, operational monitoring and mitigative measures have allayed concerns about population-level effects at most plants, but impingement mortality continues to be an issue at others.

Consultation with resource agencies reveals that impingement is a frequent concern at once-through power plants, particularly where restoration of anadromous fish may be affected. In several cases, significant modifications were made to the intake structure to substantially reduce mortality due to impingement. Impingement is an intake-related effect that is considered by EPA or state water quality permitting agencies in the development of the NPDES permits and 316(b) determinations. The impacts of impingement are small at many plants but may be moderate or even large at a few plants with once-through cooling systems. For this reason, the impingement of fish and shellfish is a Category 2 issue [Reference 2, GEIS Section 4.2.2.1.3].

Based on the research literature, monitoring reports, and agency consultations, the potential for thermal discharges to cause thermal discharge effect mortalities is considered small for most plants. However, impacts may be moderate or even large at a few plants with once-through cooling systems. For example, thermal discharges at one plant are considered by the agencies to have damaged benthic invertebrate and seagrass communities in the effluent-mixing zone around the discharge canal; as a result, helper cooling towers have been installed to reduce the discharge temperatures. Because of continuing concerns about thermal discharge effects and the possible need to modify thermal discharges in the future in response to changing environmental conditions, this is a Category 2 issue for plants with once-through cooling systems [Reference 2, GEIS Section 4.2.2.1.4].

4.3.4 Analysis of Environmental Impact

The principal concerns with once-through cooling water systems relate to the impact of intake structure design on the entrainment of larval fish and the impingement of juvenile and adult fish, and the affect of thermal discharges on the aquatic ecology of the receiving water body. Entergy Operations has performed extensive environmental monitoring, including the ecological assessment of the affects of the ANO-1 once-through cooling water system. This monitoring was required by the original ANO-1 Technical Specifications until Amendment No. 72 was issued on March 11, 1983 (0CNA038315), deleting the requirement. Subsequent to the issuance of Amendment No. 72 to the ANO-1 Technical Specifications, Entergy Operations continued this monitoring on a voluntary basis. This monitoring included entrainment studies until 1988 and impingement studies until 1994. The results of these studies are summarized below. As a note, entrainment and impingement of shellfish is not an issue because there is no significant population of endemic shellfish species in the vicinity of ANO.

4.3.4.1 Impingement and Entrainment

<u>Impingement</u>

Fish impingement occurs when juvenile and adult fish, too large to be entrained, collect on the 3/8-inch mesh screens located at the intake structure. Mortality of fish that are impinged is high at many plants because impinged organisms are eventually suffocated by being held against the screen mesh or are abraded, which can result in fatal infections. The purpose of the impingement monitoring program was to provide sufficient information for the accurate determination of impingement impacts by ANO on fish populations in Lake Dardanelle.

During the period of study, the species composition, abundance and length/weight records for impinged fish were typically collected twice a week from April to September and three times a week from September to April. Representative samples of impinged fish were collected over a 24-hour period to provide accurate estimates of weekly, monthly, and annual impingement trends [References 8, 9, 10, 11 and 12].

During the monitoring period at ANO, the total number and biomass of fish impinged was variable from year to year based on the lake temperature during the winter months. Most impingement losses within any year occurred during the winter months. The impingement studies consistently showed that over 95 percent of the number of fish impinged annually were Gizzard Shad (*Dorosoma cepedianum*) and Threadfin Shad (*Dorosoma petenense*). Approximately 5 percent of impingement totals were composed of sunfish (*Lepomis* spp.), catfish (*Ictalurus* spp.), Freshwater Drum (*Aplodinotus grunniens*), White Bass (*Morone chrysops*), Crappie (*Pomoxis* spp.), and Largemouth Bass (*Micropterus salmoides*).

It was concluded that the major cause of fish impingement was the direct result of natural cold-stressed mortality of both Threadfin Shad and Gizzard Shad populations during the winter [Reference 13]. Threadfin Shad is a warm-water, introduced species to Lake Dardanelle and exhibits cold shock stress behavior at water temperatures below 54°F. Water temperatures in Lake Dardanelle normally drop below 35°F each winter season, well below the lethal threshold temperature of approximately 41°F for Threadfin Shad. Gizzard Shad are native to the region and exhibit cold shock stress behavior over a slightly lower temperature range. The lower lethal temperature threshold for Gizzard Shad is approximately 33°F.

Both populations of shad, as well as other important forage, sport, and commercial fish species, were also monitored in annual far-field investigations in Lake Dardanelle beyond the influence of ANO. The results of these studies also provided supporting evidence that significant fluctuations in local shad populations occur naturally in the lake and are directly related to low seasonal water temperatures [Reference 13]. It was concluded that impinged shad that accumulated at the ANO intake structure were either already dead and drifting in the intake area or were cold-stressed and unable to avoid the moderate flow rates at the intake screens. It was also concluded that Threadfin Shad and Gizzard Shad populations are able to reestablish themselves in the intake area and other areas of the lake each year.

During the course of impingement monitoring at ANO, it was also shown that no significant losses in the standing crop of other fish populations in Lake Dardanelle occurred due to impingement or seasonal cold stress mortality. In 1995, the Arkansas Game and Fish Commission concluded that impingement losses have not affected the maintenance of a quality recreational fishery in Lake Dardanelle [Reference 14].

Based on the impingement studies performed, no significant changes have occurred to native fish populations. In addition, no significant changes have been made to the operation of the ANO intake structure since construction. Previous studies indicate that continuation of the observed levels of impingement should not result in any significant adverse environmental impact during the period of extended operation.

Entrainment

Entrainment occurs when planktonic larval fish drifting in the lake are carried with cooling water through the intake screens, pumps, and steam condensers. High mortality to larval fish results from mechanical and hydraulic forces experienced within the cooling system. Although studies have shown some larval fish survive entrainment, it is usually assumed that 100 percent mortality occurs.

The entrainment of larval fish at ANO was monitored for several years [References 15 and 16]. The purpose of the entrainment monitoring program was to provide sufficient information for the accurate determination of entrainment impacts by ANO on fish populations in Lake Dardanelle. The objective of the monitoring program was to determine the species composition and abundance of larval fish entrained at ANO during the peak spawning period from April to June each year. Results of these studies were correlated with standing crop fish community data collected in a related study performed in several areas in Lake Dardanelle. The results of entrainment monitoring consistently showed that the impact of entrainment losses to fish populations in Lake Dardanelle were not significant. For most of the years monitored, over 95 percent of the larval fish entrained at ANO were Gizzard Shad and Threadfin Shad (*Clupeidae*). Approximately 5 percent of the entrainment losses were composed of other locally abundant fish populations such as Carp (*Cyprinidae*), Suckers (*Catostomidae*), and White Bass (*Morone chrysops*), and Freshwater Drum (*Aplodinotis grunniens*).

These studies demonstrated that entrainment losses did not adversely effect abundant Clupeidae populations, or any other population of fish or aquatic organisms, in Lake Dardanelle within the influence of the ANO intake structure. In 1995, the AGFC also concluded that entrainment losses have not affected the maintenance of a quality recreational fishery in Lake Dardanelle [Reference 14].

Based on the entrainment studies performed, no significant changes have occurred to native fish populations. In addition, no significant changes have been made to the operation of the ANO intake structure since construction. Previous studies indicate that continuation of the observed levels of entrainment should not result in any significant adverse environmental impact during the period of extended operation.

4.3.4.2 Heat Shock

Lake Dardanelle is used as the source of heat dissipation for the ANO-1 once-through cooling water system. The lake was constructed by the U.S. Army Corps of Engineers in 1966 as part of the McClellan-Kerr Arkansas River Navigation Project. The 50-mile long lake has a surface area of approximately 37,000 acres and a storage capacity of 486,000 acre-feet.

With four circulating water pumps in operation, the ANO-1 once-through cooling water system has a design flow of 1738 cfs and increases the temperature of ambient intake lake water a maximum of 15°F as it passes through the plant [Reference 1]. Heated cooling water is discharged to Lake Dardanelle through a 520-foot long canal and an 80-acre embayment of the lake.

Thermal discharge limits for ANO (Outfall 001) are currently established in NPDES Permit Number AR0001392, dated September 30, 1997 [See Attachment B]. Thermal effluent discharge limits for Outfall 001 are 110°F daily maximum and 105°F daily average. These limits apply to the point where the cooling water enters the 520-foot long discharge canal. Since 1973, when the facility was originally permitted to discharge cooling water to Lake Dardanelle, no violations of established thermal permit limits have occurred at ANO.

A specific condition of NPDES Permit No. AR0001392 requires the applicant to monitor water temperatures after the discharged cooling water passes through the discharge embayment (mixing zone) and enters the main channel of Lake Dardanelle. During the period from June to September, water temperatures are monitored twice a month at three locations in Lake Dardanelle within the influence of the ANO cooling water discharge. This monitoring is performed to ensure the thermal water quality standard for the lake is not exceeded.

The Arkansas Water Quality Standard for Lake Dardanelle is 95°F. Because water quality standards for temperature are being met in Lake Dardanelle, no Section 316(a) variance is required or needed. In support of previous conclusions by state and federal regulatory agencies and Entergy Operations [References 17 and 18], the AGFC also concluded in 1995, that thermal impacts from ANO have not affected the maintenance of a quality recreational fishery in Lake Dardanelle [Reference 14].

4.3.5 Consideration of Alternatives for Reducing Adverse Impacts

Entergy Operations has operated both the cooling system and the water intake for ANO in a manner that has resulted in no significant adverse impacts on the aquatic communities of Lake Dardanelle. This result is evidenced by state and federal water quality and wildlife resource agencies concluding that the operation of ANO has had no significant adverse impacts on Lake Dardanelle. Therefore, impacts are small and mitigation measures were not further considered.

4.4 Ground-Water Use Conflicts (Ranney Wells)

4.4.1 Requirement [10CFR51.53(c)(3)(ii)(C)]

If the applicant's plant uses Ranney wells or pumps more than 100 gallons (total onsite) of ground water per minute, an assessment of the impact of the proposed action on ground water use must be provided.

4.4.2 Analysis of Environmental Impact

There are no Ranney wells or other wells in use on the ANO site. Drinking water is supplied from the City of Russellville and service water is taken from Lake Dardanelle. Therefore, this issue is not applicable to ANO and analysis is not required.

4.5 Ground-Water Quality

4.5.1 Requirement [10CFR51.53(c)(3)(ii)(D)]

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.

4.5.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"Sites with closed-cycle cooling ponds may degrade groundwater quality. For plants located inland, the quality of the groundwater in the vicinity of the ponds must be shown to be adequate to allow continuation of current uses. See 10CFR51.53(c)(3)(ii)(D)."

4.5.3 GEIS Background

The extent of groundwater contamination by cooling ponds has not been documented at this time. Off-site groundwater monitoring is not standard practice at these sites, and there are no data with which to characterize the significance of potential off-site groundwater contamination. For those plants with cooling ponds located in a salt marsh, groundwater quality is not a significant concern because groundwater quality beneath salt marshes is too poor for human use. Because continued infiltration into the shallow aquifer will not change its groundwater use category (which is already restricted to industrial uses only) and because potential mitigation measures would be costly, no mitigation measures beyond those implemented during the current term license would be warranted. Therefore, for plants with cooling ponds located in salt marshes, this is a Category 1 issue. The impact on groundwater quality for plants with cooling ponds that are not located in salt marshes is a Category 2 issue [Reference 2, GEIS Section 4.8.3].

4.5.4 Analysis of Environmental Impact

ANO-1 uses once-through cooling as the heat dissipation system. It is not necessary to assess the impact of license renewal on groundwater quality for plants with cooling systems other than cooling ponds.

ANO does have an emergency cooling pond which would be used as an auxiliary heat dissipation system should the Lake Dardanelle water source be lost at the intake structure. This cooling pond is permitted by the ADEQ as NPDES Outfall 009, with all monitoring activities controlled under NPDES Permit Number AR0001392. The pond was excavated from an area of heavy clay and silty-clay soils that range from 13 to 24 feet deep. These soils, which have low hydraulic permeabilities [Reference 1], serve as an aquiclude, or impervious cap, over the water-bearing shale strata below, and prevent the upward flow of water from the shale strata and the downward percolation of surface water from the emergency cooling pond [Reference 19]. An additional clay liner was also installed during pond construction to maintain a low hydraulic gradient between the pond and underlying soils to ensure that leakage did not occur [Reference 20]. Rotenone (fish eradication), a biocide (zebra mussels), and a dechlorinating agent (oxidants) are periodically added to the pond. Entergy Operations concludes that ground-water contamination from the cooling pond is insignificant due to soil bearing formations. In addition, the ground-water under the pond flows in the direction of Lake Dardanelle.

4.5.5 Consideration of Alternatives for Reducing Adverse Impacts

Since ANO-1 utilizes once-through cooling water from Lake Dardanelle as the primary heat dissipation system and offsite groundwater quality is unaffected by the emergency cooling pond due to the soil bearing formations, mitigation measures for reducing or avoiding this type of adverse environmental effect were not considered further.

4.6 Refurbishment Impacts on Important Plant and Animal Habitats, and Threatened or Endangered Species

4.6.1 Requirement [10CFR51.53(c)(3)(ii)(E)]

All license renewal applicants shall assess the impact of refurbishment and other license renewal related construction activities on important plant and animal habitats. Additionally, the applicant shall assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act.

4.6.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"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. See 10CFR51.53(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. See 10CFR51.53(c)(3)(ii)(E)."

4.6.3 GEIS Background

The issue of impacts to threatened or endangered species is potentially relevant to all cooling system types and to transmission lines. Review of power plant operations has shown that neither current cooling system operations nor electric power transmission lines associated with nuclear power plants are having significant adverse impacts on any threatened or endangered species. However, widespread conversion of natural habitats and other human activities continues to cause the decline of native plants and animals. As biologists review the status of species, additional species threatened with extinction are being identified; consequently, it is not possible to ensure that future power plant operations will not be found to adversely affect some currently unrecognized threatened or endangered species.

In addition, future endangered species recovery efforts may require modifications of power plant operations. Similarly, operations-related land-disturbing activities (e.g., spent fuel and low-level waste storage facilities) could affect endangered species. As noted in GEIS Section 3.2, without site-specific and project-specific information, the magnitude or significance of impacts on threatened and endangered species cannot be assessed. For these reasons, the nature and significance of nuclear power plant operations on as yet unrecognized endangered species cannot be predicted; and no generic conclusion on the significance of potential impacts on endangered species can be reached. The impact on threatened and endangered species, therefore, is a Category 2 issue [Reference 2, GEIS Section 4.1].

Potential impacts of refurbishment on federal- or state-listed threatened and endangered species, and species proposed to be listed as threatened or endangered, cannot be assessed generically because the status of many species is being reviewed and it is impossible to know what species that are threatened with extinction may be identified that could be affected by refurbishment activities. In accordance with the Endangered Species Act of 1973 (Pub. L. 93-205), the appropriate federal agency (either the U.S. Fish and Wildlife Service or the National Marine Fisheries Service) must be consulted about the presence of threatened or endangered species. At that time, it will be determined whether such species could be affected by the refurbishment activities and whether formal consultation will be required to address the impacts. Each state should be consulted about its own procedures for considering impacts to state-listed species. Because compliance with the Endangered Species Act cannot be assessed without site-specific consideration of potential effects on threatened and endangered species, it is not possible to determine generically the significance of potential impacts to threatened and endangered species. This is a Category 2 issue [Reference 2, GEIS Section 3.9].

4.6.4 Analysis of Impacts from Refurbishment Activities on Important Plant/Animal Habitats

There are no major refurbishment activities required for license renewal at ANO–1 [See Section 3.2]. Therefore, no further analysis of the impact of this issue is required.

4.6.5 Analysis of Impacts of the Proposed Action on Threatened or Endangered Species

4.6.5.1 Federal-Listed Species

Two mammal and four bird animal species currently protected under the Endangered Species Act have geographic ranges that possibly include the ANO site area. These include the Florida panther (*Felis concolor coryi*), bald eagle (*Haliaeetus leucocephalus*), red-cockaded woodpecker (*Picoides borealis*), interior least tern (*Sterna antillarum*), gray myotis *(Myotis grisescens)*, and Bachman’s warbler (*Vermivora bachmanii*). Of these species, the bald eagle is currently listed as threatened with the remaining species listed as endangered. Only the bald eagle is known to occasionally frequent the ANO site area. Suitable habitat for the other five species is not found within or near project boundaries, and none has been reported from the project area. No federally-listed fish, reptiles, amphibians, or invertebrate species or appropriate habitats for them have been identified within the ANO site area. In addition, no federally-listed plant species having a potential for occurrence has been identified within the ANO site area.

There are no recent records for the Florida panther in Arkansas, although the state was included in its historical range [Reference 21]. U.S. Fish and Wildlife Service reports that it is "highly unlikely that viable populations of the Florida panther presently occur outside Florida" [Reference 22].

Suitable roosting and feeding habitat for the bald eagle probably does not exist within the ANO site area, although a potential for occasional stray birds to fly within the site area possibly exists during winter months. A small resident population may occur in the Arkansas River Valley region, but there is no evidence of suitable nesting habitat within the site area. A bald eagle nest site was reported at a distance of approximately 10 miles from the site area several years ago, but it is not known whether the nest had some potential for nesting or whether it represented a practice nest by a juvenile bird. Bald eagle nests typically are placed in very large living trees and away from heavily impacted sites. No trees having a potential to serve as suitable nesting sites have been identified within the site area.

There are historical records of the red-cockaded woodpecker in Yell County at distances of approximately 40 miles from the ANO site area [References 23 and 24]. The species is no longer present at those localities, however, and the closest remaining colonies of birds are in Scott County at a distance of greater than 40 miles from the site area [Reference 25]. Suitable habitat does not exist for this species in the site area; therefore, it is not expected to be present.

The interior least tern requires exacting sand bar conditions, i.e., sand bars in the Arkansas River having very low vegetation cover and affording some protection from predators and flooding [Reference 24]. These habitat conditions are not present within the site area.

Bachman's warbler continues to appear on the list of federally-listed species occurring in Arkansas. Inclusion of the species on the Arkansas list is based on historical records, however, and the species is almost certainly extinct throughout its range. If still to be found at any location, this species is probably to be expected only in South Carolina [Reference 22].

Critical habitat has not been designated in Arkansas by the U.S. Fish and Wildlife Service for any of the six species, i.e., Florida panther, gray myotis, and the four bird species [Attachment C]. A formal onsite survey at ANO was not required by the U.S. Fish and Wildlife Service.

In addition, the U.S. Fish and Wildlife Service was contacted [Attachment C] to identify any new information regarding federally-listed species along the transmission lines that were constructed to support ANO-1. No records of any federally-listed species were identified.

4.6.5.2 State-Listed Species

The ANHC was contacted for information regarding state-listed threatened and endangered species in the vicinity of ANO. Although ANHC has no regulatory or enforcement authority, it is the state agency designated to maintain the Arkansas list of state threatened species, state endangered species, and a diverse inventory of other elements (important plant, animal, and habitat records). ANHC applies the term "state threatened" to native species that are believed likely to become endangered in Arkansas in the foreseeable future, based on current inventory information. ANHC applies the term "state endangered" to native species that are in danger of being extirpated from the state. The state-level threatened and endangered species lists for Arkansas contain no animal species and only a limited number of plant species. No state-listed threatened or endangered plant species were identified in the records of ANHC for the ANO site [Attachment D].

In addition to state-level threatened and endangered species lists, other elements in the ANHC inventory include records such as outstanding examples of natural communities, colonial nesting sites, outstanding scenic, and geologic features. The inventory also contains information regarding plants and animals that may be federally-listed as threatened or endangered, rare in Arkansas, peripheral (i.e., around the borders of Arkansas) to Arkansas, or of an undetermined status in the state. A list of element occurrences for Pope County was obtained from the inventory records maintained by ANHC [Attachment D]. Seven database elements of special concern to ANHC have been reported to occur in the vicinity of ANO. These elements include the following plant and animal species and habitat types: Rafinesque's big-eared bat (*Corynorhinus rafinesquii*), gray myotis (*Myotis grisescens*), longnose darter (*Percina nasuta*), Northern crayfish frog (*Rana areolata circulosa*), Riddell's spike moss (*Selaginella riddellii*), Ozark spiderwort (*Tradescantia ozarkana*), and sandstone glade/outcrop habitat. None of these seven elements are classified as state-level threatened or endangered species.

Of the species in the ANHC inventory for Pope County having known occurrences on the Russellville West topographic quadrangle map, suitable habitat possibly exists within the site area for one of them, the Northern crayfish frog. The Northern crayfish frog is not a state listed species, but it represents a species that has been tracked by ANHC for several years as an S1 species [Reference 26]. ANHC defines a S1 species as "extremely rare" and "may be especially vulnerable to extirpation." In May 1999, Dr. Stanley E. Trauth (an Arkansas herpetofauna authority) recommended to ANHC that the Northern crayfish frog's ranking should be changed to S3 [Reference 27]. ANHC defines S3 species as "Rare to uncommon; typically between 20 and 100 estimated occurrences, may have fewer occurrences but with large number of individuals in some populations, may be susceptible to large-scale disturbances." Dr. Trauth assessed the State Protection Needs for the species as "none at the present time," and based on his recommendations, there does not appear to be cause for concern for the Northern crayfish frog at the site area.

The ANO site area also contains a very few small areas of sandstone glade/outcrop habitat, which represents an element tracked by the ANHC but which is afforded no protection under state or federal law. Since these small areas of sandstone/glade habitat have already been impacted during initial construction activities, they have likely lost their original habitat value.

The ANHC staff agreed that ANO represents an industrial site that has experienced alteration of much of its original vegetation cover and natural habitat value. Therefore, the probability of identifying any of the seven elements of special concern on the ANHC inventory would be remote and not justify an on-site survey at ANO [Attachment D].

The ANHC and Arkansas Game and Fish Commission were also contacted [Attachments D and E] to identify any new information regarding state-level threatened and endangered species along the transmission lines that were constructed to support ANO-1. No records of any state-listed threatened species, endangered species, or any other species of concern were identified.

4.6.5.3 Conclusion of Impacts

The continued operation of ANO-1 will not impact threatened and endangered species because no federally-listed or state-listed threatened and endangered species, other important species, or habitats of concern to the state are known to exist at the site. Correspondence with the U.S. Fish and Wildlife Service and the Arkansas Natural Heritage Commission relative to special status species issues is provided in Attachments C and D.

4.6.6 Consideration of Alternatives for Reducing Adverse Impacts

There are no major refurbishment activities required for license renewal at ANO–1 [See Section 3.2]; therefore, no analysis of the impact of this issue is required. In addition, no federally-listed or state-listed threatened and endangered species, other important species, or habitats of concern to the state are known to exist at the site or along the transmission lines. Therefore, there are no impacts necessitating consideration of alternatives.

4.7 Vehicle Exhaust Emissions

4.7.1 Requirement [10CFR51.53(c)(3)(ii)(F)]

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.

4.7.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"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. See 10CFR51.53(c)(ii)(3)(F)."

4.7.3 Analysis of Environmental Impact

ANO is not located in, or near, a nonattainment or maintenance area for air pollutants, from either the federal or state regulatory standpoint. The nearest nonattainment areas to ANO are the Dallas/Ft. Worth, Texas metropolitan area, over 300 miles southwest of the site, and the Memphis, Tennessee metropolitan area located approximately 200 miles east of the site. Additionally, there are no major refurbishment activities required for license renewal at ANO–1 [See Section 3.2]. Therefore, no further analysis of the impact of this issue is required.

4.8 Microbiological (Thermophilic) Organisms

4.8.1 Requirement [10CFR51.53(c)(3)(ii)(G)]

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

4.8.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"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. See 10CFR51.53(c)(3)(ii)(G)."

4.8.3 GEIS Background

Public health questions require additional consideration for the 25 plants using cooling ponds, lakes, canals, or small rivers because the operation of these plants may significantly enhance the presence of thermophilic organisms. The data for these sites are not now at hand and it is impossible to predict the level of thermophilic organism enhancement at any given site with current knowledge. Thus, the impacts are not known and are site-specific. Therefore, the magnitude of the potential public health impacts associated with thermal enhancement of *N. fowleri* cannot be determined generically. This is a Category 2 issue [Reference 2, GEIS Section 4.3.6].

4.8.4 Analysis of Environmental Impact

ANO was one of eleven nuclear plants in 1981 that participated in a study regarding the possible presence of thermophilic pathogens in cooling water systems [References 28, 29, and 30]. In addition, ANO was one of ten sites where thermophilic free-living amoebae were detected. Tests indicated, however, that the amoebae were not pathogenic as *Naegleria* sp. was not detected in water and sediment samples collected from the ANO intake canal or discharge embayment. *Legionella* was detected in water samples collected at ANO (Lake Dardanelle) and several control sources of surface water in the area. Concentrations of *Legionella* in the ANO cooling water systems were similar to concentrations in local surface water control sources.

Studies regarding the presence of thermophilic pathogens at ANO concluded that any risk for infection from contact with aerosols containing *Legionella* sp. was an industrial hygiene concern that could be effectively managed using standard industrial hygiene practices. No concerns regarding public exposure to aerosols containing *Legionella* were identified. Because pathogenic *Naegleria* sp. was not detected in samples collected from Lake Dardanelle or the ANO discharge embayment, the human health risks associated with this microorganism were considered to be very low or insignificant. No specific studies were developed to address the possible presence of naturally occurring thermophilic microorganisms such as *Salmonella*, *Shigella*, *Aeromonas*, and *Pseudomonas* at ANO.

The ADH was contacted to identify any possible concerns state health officials had concerning waterborne thermophilic pathogens in Lake Dardanelle and the Arkansas River system. Several officials, including the State Epidemiologist, indicated that no information was available to indicate that a human health exposure problem exists with thermophilic pathogens in Lake Dardanelle or the Arkansas River [Reference 31]. They noted that one case, reported in approximately 1980, involved an individual who died soon after contracting amoebic meningoencephalitis. Public health officials suspected the victim's swimming in warm, shallow water in the Arkansas River may have lead to the infection. The cause of the disease and its source were never confirmed. The suspected location of the contaminated river water was approximately 175 miles downstream from ANO.

There has been no known impact of ANO-1 operation on public health related to thermophilic microorganisms. Since no changes are planned to the operation of the cooling water discharge, no such impact is likely to occur as a result of license renewal.

4.8.5 Consideration of Alternatives for Reducing Adverse Impacts

Entergy Operations complies with the directives issued by the ADH regarding public health, thermophilic organisms, and their relationship to ANO-1 operation. No mitigation measures beyond those required by ADH during the current term of ANO-1 operation would be expected as a result of license renewal.

4.9 Electrical Shock from Induced Currents

4.9.1 Requirement [10CFR51.53(c)(3)(ii)(H)]

If the applicant's transmission lines that were constructed for the specific purpose of connecting the plant[6] to the transmission system do not meet the recommendations of the National Electric Safety Code for preventing electric shock from induced currents, an assessment of the impact of the proposed action on the potential shock hazard from the transmission lines must be provided [10CFR51.53(c)(3)(ii)(H)].

4.9.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"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 electrical shock potential at the site[7]. See 10CFR51.53(c)(3)(ii)(H)."

4.9.3 GEIS Background

The transmission lines of concern are those between the plant and the intertie to the transmission system. With respect to shock safety issues and license renewal, three points must be made. First, in the licensing process for the earlier licensed nuclear plants, the issue of electrical shock safety was not addressed. Second, some plants that received operating licenses with a stated transmission line voltage may have chosen to upgrade the line voltage for reasons of efficiency, possibly without reanalysis of induction effects. Third, since the initial NEPA review for those utilities that evaluated potential shock situations under the provision of the NESC, land-use may have changed, resulting in the need for reevaluation of this issue.

6 The plant is defined as the nuclear reactors, steam-electric systems, intakes, discharges, and all other on-station facilities involved in the production of electricity. Transmission lines and other off-station facilities are not part of the plant. (NUREG-1555, Standard Review Plan for Environmental Reviews for Nuclear Power Plants, Introduction Chapter, Definitions, February 1999)

7 The site is considered to be synonymous with 'Station', which is defined as all facilities (reactors, control buildings, intakes, discharges, etc.) that are located on the applicant's site. Transmission lines and their associated facilities are not considered part of the station. (NUREG-1555, Standard Review Plan for Environmental Reviews for Nuclear Power Plants, Introduction Chapter, Definitions, February 1999)

The electrical shock issue, which is generic to all types of electrical generating stations, including nuclear power plants, is of small significance for transmission lines that are operated in adherence with NESC. Without review of each nuclear plant's transmission line conformance with NESC criteria, it is not possible to determine the significance of the electrical shock potential. This is a Category 2 issue [Reference 2, GEIS Sections 4.5.4 and 4.5.4.1].

4.9.4 Analysis of Environmental Impact

To connect the ANO-1 nuclear unit into the transmission system required construction of four transmission lines in the early 1970's. These lines are shown in Figure 4.9-1 and are listed in Table 4.9-1.

The transmission lines in Table 4.9-1 have remained at the same operating voltage levels since the ANO units were placed into service. These transmission lines have not been upgraded to operate at higher voltage levels and have not been moved since their initial installation. The clearances along these transmission lines were initially designed for most land uses (i.e., county roads, farm machinery, etc.). Since Entergy Arkansas holds easements to the land beneath the transmission lines and monitors these transmission lines by aerial surveillance during the year, Entergy Arkansas controls the land use. If the ANO units were removed from service, these transmission lines would have to remain in service to provide power for the area transmission loads due to the significant increase in area loads since the construction of the ANO units.

To provide a safeguard for persons who may be in close proximity to electric power lines, the National Electrical Safety Code identifies minimum vertical clearances for electric lines operating at various voltage levels. Regulatory bodies usually require that utilities construct transmission lines according to either the latest edition of the NESC or to a specified edition adopted by the body; however, they do not require existing transmission lines to be upgraded to meet revisions of the code. In addition, the NESC does not require maintenance replacements to comply with latest code, unless a structure is replaced. Vertical clearance to facilities on the pole are required to have current code dimensions (for example, communication lines, transformers, etc.).

The two 500 kV transmission lines (48 miles) presently meet the 1997 NESC clearances of 28.35 feet at a maximum operating temperature of 212°F.

The two 161 kV transmission lines (built for ANO-1 which total 50 miles in length) are composed of aluminum conductors and were constructed in 1971 in compliance with the then applicable sixth edition of the NESC (1961). When initially installed, these transmission lines were designed for 26 feet clearance at a temperature of 120°F. The loadings on these transmission lines have increased since the initial installation, resulting in increased conductor temperatures and increased sag. Since installation, these ground clearances could decrease to less than 21 feet at maximum possible conductor operating temperatures (a clearance value required in the 1997 NESC). Consequently, these two transmission lines might not presently meet the 1997 NESC requirements for clearance (21 feet to ground) during certain limited transmission line outages, which result in maximum possible conductor operating temperatures. However, the transmission lines continue to meet the previous code (1961) to which they were constructed. The clearances to ground currently exceed the height of vehicles expected to pass under these lines. Also, to Entergy-Arkansas' knowledge, no incidents of electric shock have been reported from these lines since they were placed into service.

The earlier standards, to which these four transmission lines were constructed, did not specifically address electric shock that could be experienced by a person contacting a large vehicle parked under the transmission lines. This was added to the more recent NESC editions which states that for voltages exceeding 98 kV to ground (169.7 kV phase to phase), either the clearance must be increased or the effects thereof shall be reduced by other means, as required, to limit the steady-state current due to electrostatic effects to 5 mA (root-mean-square), if the largest anticipated truck, vehicle, or equipment under the transmission line were short-circuited to ground. The size of the anticipated truck, vehicle, or equipment used to determine the clearances may be less than, but need not be greater than, that limited by federal, state, or local regulations governing the area under the transmission line. For this determination, the conductors shall be at a final unloaded sag of 50°C (120°F).

The necessary studies have been performed to determine whether the two 500 kV transmission lines built for ANO-1 have adequate clearances to limit the steady-state current for the largest anticipated truck parked under the transmission line to the 5-mA limit. The 161 kV transmission lines were excluded from this study since their voltages to ground do not exceed 98 kV to ground and therefore, do not apply to this NESC code requirement (Note - the 161 kV transmission lines do not generate an electric field of enough magnitude to cause a shock hazard).

EPRI has published a reference book [Reference 32] and has developed a computer code called ENVIRO [Reference 33], which together are used to calculate the steady-state current value from transmission lines. The calculation is a two-step process in which the analyst calculates the average field strength at one meter (3.28 feet) above the ground beneath the minimum line clearance, and then calculates the steady-state current value.

The two 500 kV transmission lines were evaluated for this 5-mA standard. The largest vehicle that would routinely be anticipated being under these 500 kV transmission lines is a tractor-trailer (75 feet long, 8.5 feet wide, and 13.5 feet high) parked on or alongside the roadway. These transmission line clearances, together with transmission line characteristics such as voltage and conductor position, have been entered into the ENVIRO code, to obtain electric field strengths at one-foot intervals, one meter above the ground. The maximum calculated average field strength is determined (in kV per meter) while placing a 75-foot object under and perpendicular to the transmission lines (representing a large tractor-trailer rig). Using the maximum average field strength, in accordance with the EPRI reference book, the steady-state current for a tractor trailer 75 feet long, 8.5 feet wide, and 13.5 feet high at the road crossings under these two 500 kV transmission lines was calculated. The resultant values were found to be greater than the 5-mA limit established by the NESC for three of the nine major road crossings. The highest level of 5.54 mA appeared at a 500 kV crossing having a 37.2 feet clearance at 120°F and an average maximum field strength of 6.03 kV/meter. However, for these few situations, it is not deemed necessary to take any mitigating measures for these road crossings for the following reasons:

- The likelihood that a large truck would park in perfect orientation directly under one of the nine major road crossings on this 48 miles of 500 kV transmission lines is remote.

- Although the 1997 NESC uses 5 mA as a limit, this value would not actually flow through a person touching such a vehicle. The actual flow of current would be a small fraction of the 5 mA limit and would not result in any safety concern for an adult or child. The 5 mA value could only occur when the vehicle is perfectly insulated and the person is perfectly grounded. Research has shown [Reference 32] that for a large school bus, the median value of short-circuit current through a body touching the school bus is only 1 to 4 percent of the calculated short-circuit level. Thus, if 5 mA were calculated (a value conservatively used as a let-go current level for children), then the average person would only have 0.05 to 0.2 mA flowing through his body. This 0.05 to 0.2 mA value is not perceptible for the average adult and would at most be "perceptible without shock" to a child. As is stated in this reference, "if the line is designed according to code (i.e., within the 5 mA. short-circuit limit), short-circuit currents to a person would be below minimum perception levels." Therefore, it is not believed that there is a need to modify the two 500 kV transmission lines (at the three crossings) that exceed the 5 mA limit by at most 10.8 percent, when contact with this large vehicle would result in a shock that would be barely perceptible.

- Without a transmission line change or planned modification to the transmission line as specified within the NESC Code, it is not normally the policy to reconstruct existing facilities (that were initially built to applicable code standards) in order to meet later or more restrictive code standards. The NESC does not require utilities to modify existing facilities to comply with later revisions of the code as long as those facilities complied with prior editions of the code except as possibly required by the administrative authority.

For off-the-road clearances, the minimum clearance for the two 500 kV transmission lines was found to be 35 feet at 120°F. At the maximum operating transmission line temperature of 212°F, this clearance would meet the NESC requirement of 28.35 feet. In addition, a very large school bus (40 feet long by 11 feet high by 8 feet wide) was placed at an off-road location to simulate the largest possible vehicle or agriculture combine that possibly might be located in a field location. The resultant calculations determined that the short circuit currents for this large school bus were 3.95 mA, which is less than the 5 mA 1997 NESC limit.

It should also be noted that the ANO generating plant is located in close proximity to the ANO switchyard, where the above transmission lines are terminated. A 500 kV transmission line connects the ANO-1 generator to this switchyard. Additionally, a short 161 kV transmission line runs from the plant to this switchyard for offsite power requirements. These transmission lines are very short, less than 1600 feet, and meet the 1997 NESC requirements for clearance and electric shock for large vehicles.

4.9.5 Consideration of Alternatives for Reducing Adverse Impacts

Based on the above information, the impact of the potential for electric shock is small. Since these four transmission lines would remain in-service regardless of license renewal, license renewal will have no impact on shock hazard. Further, the potential for shock hazard is not significant, and mitigation is not considered to be warranted.

Table 4.9-1, Transmission Lines Built for Installation of ANO-1

Line Description	Voltage	Distance (Miles)	Year Line Was Energized
Tap on Ft. Smith-Mabelvale Line Connection of ANO-1 to Mabelvale	500 kV	24.16	1971
Tap on Ft. Smith-Mabelvale Line Connection of ANO-1 to Fort Smith	500 kV	24.07	1971
ANO-1 - Morrilton East	161 kV	38.89	1971
ANO-1 - Russellville East	161 kV	11.98	1971
TOTALS	500 kV 161 kV	48.23 50.87	

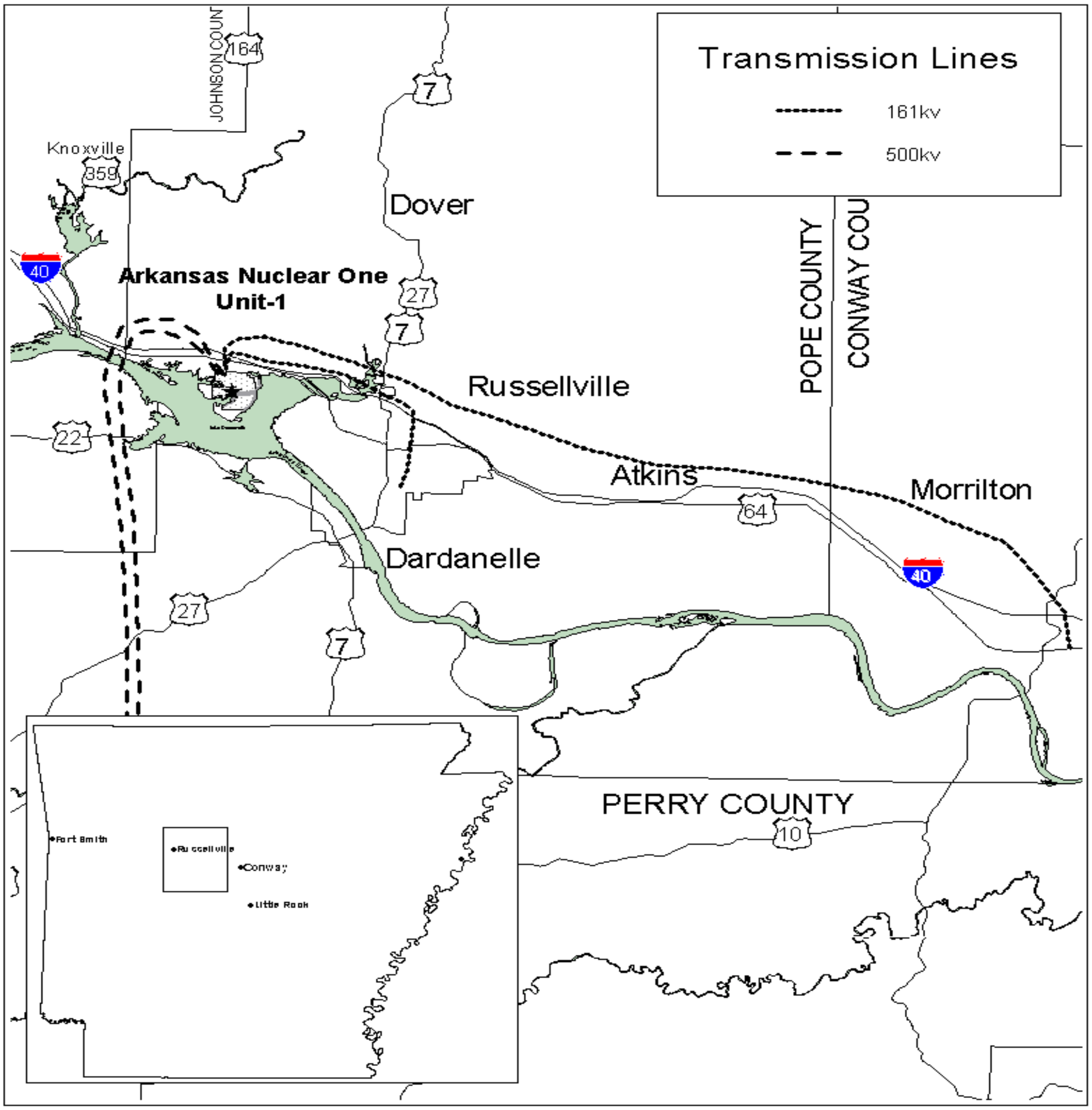

Figure 4.9-1, Transmission Lines from ANO-1 to the Transmission System

4.10 Housing, Land-Use, Public Schools and Public Water Supply Impacts

4.10.1 Requirement [10CFR51.53(c)(3)(ii)(I)]

An assessment of the impact of the proposed action on housing availability, land-use, and public schools (impacts from refurbishment activities only) within the vicinity of the plant must be provided. Additionally, the applicant shall provide an assessment of the impact of population increases attributable to the proposed project on the public water supply.

4.10.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"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 in areas with growth control measures that limit housing development. See 10CFR51.53(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. Most sites would experience impacts of small significance but larger impacts are possible depending on site- and project-specific factors. Impacts may be of moderate significance at plants in low population areas."

"Significant changes in land-use may be associated with population and tax revenue changes resulting from license renewal. See 10CFR51.53(c)(3)(ii)(I)."

4.10.3 Estimates of Workforce During the License Renewal Term

The socioeconomic impacts of license renewal are addressed in the GEIS; in particular see Volume 1, Section 3.7, and Section 4.7. Volume 2 of the GEIS, Appendix C (Socioeconomics) includes the results of a case study, for the area around ANO, of the socioeconomic impacts associated with refurbishment activities and continued operation during the license renewal term. In GEIS Appendix C, Section C.4.1, the impact of estimated increases in staff at ANO is evaluated in terms of the population of Pope County. The 1990 census showed the population of Pope County to be 45,883 persons. The Census Bureau estimate of the 1997 population for Pope County is 51,219.

The GEIS assumes that an additional staff of 60 permanent workers will be required during the license renewal period. This evaluation also accounted for indirect employment and for in-migration of workers and their families to Pope County. The evaluation found that the increase would represent less than 0.3 percent of Pope County's population in 2014. Entergy Operations has not identified any increases in staffing related to license renewal-related programs; therefore, there would be no corresponding increase in direct or indirect workers in Pope County due to the proposed action. Therefore, the GEIS evaluation overestimates the increase in staff at ANO-1 during the license renewal term.

Housing Availability - GEIS Background

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.

The impacts on housing are considered to be of moderate significance when there is a discernible but short-lived reduction in available housing units because of project-induced in-migration. The impacts on housing are considered to be of large significance when project-related demand for housing units would result in very limited housing availability and would increase rental rates and housing values well above normal inflationary increases in the state.

Moderate and large impacts are possible at sites located in rural and remote areas, at sites located in areas that have experienced extremely slow population growth (and thus slow or no growth in housing), or where growth control measures that limit housing development are in existence or have been recently lifted. Because impact significance depends on local conditions that cannot be predicted at this time, housing is a Category 2 issue [Reference 2, GEIS Section 3.7.2].

Analysis of Impact of the Proposed Action on Housing Availability

The GEIS, Volume 2, Appendix C, Table C.21, indicates that in the year 2013, the projected direct and indirect plant related employment at ANO will be 2964 persons. This is 8.9 percent of the total Pope County employment, as indicated in GEIS Table C.21. The GEIS estimated that an additional 60 workers would be required at ANO-1 during the license renewal period and that this would cause only small new housing impacts. Based on a site-specific review, the impact of license renewal on housing availability is expected to be even smaller than that discussed in the GEIS. Since no major refurbishment activities have been identified, and there is no identified need to increase plant staff for the period of extended operation, impact on housing availability is expected to be very small.

Land-Use - GEIS Background

The issue evaluated in this section concerns refurbishment-induced changes to local land use and development patterns. Because the value attributed to land-use changes can vary for different individuals and groups, this analysis does not attempt to conclude whether such changes have positive or negative impacts. The impacts to off-site land use are considered small if population growth results in very little new residential or commercial development compared with existing conditions and if the limited development results only in minimal changes in an area's basic land-use pattern. Land-use impacts are considered to be moderate if plant-related population growth results in considerable new residential or commercial development and the development results in some changes to an area's basic land-use pattern. The impacts are considered to be large if population growth results in large-scale new residential or commercial development and the development results in major changes in an area's basic land-use pattern. Based on predictions for the case study sites, refurbishment at all nuclear plants is expected to induce small or moderate land-use changes. There will be new impacts, but for almost all plants, refurbishment-related population growth would typically represent a much smaller percentage of the local areas' total population than did original construction-related growth. Because future impacts are expected to range from small to moderate, and because land-use changes could be considered beneficial by some community members and adverse by others, this is a Category 2 issue [Reference 2, GEIS Section 3.7.5].

Based on predictions for the case study plants, it is projected that all new population-driven land-use changes during the license renewal term at all nuclear plants will be small because population growth caused by license renewal will represent a much smaller percentage of the local area's total population than has operations-related growth. Also, any conflicts between offsite land use and nuclear plant operations are expected to be small. In contrast, it is projected that new *tax-driven* land-use changes may be moderate at a number of sites and large at some others. Because land use changes may be perceived by some community members as adverse and by others as beneficial, the staff is unable to assess generically the potential significance of site-specific off-site land use impacts. This is a Category 2 issue [Reference 2, GEIS Section 4.7.4.2].

Analysis of Impact of the Proposed Action on Land-Use

Appendix C of the GEIS contains an analysis of land-use for the area around ANO. This analysis evaluated the direct and indirect land-use impacts resulting from the extension of the license, and concluded that: "With the plant-related population increase projected for Pope County, the land-use impacts of ANO refurbishment are expected to be small."

"The indirect land-use impacts of ANO-1's license renewal term are expected to be moderate. Population growth associated with the plant's continued operation is projected to represent only a 0.3 percent increase in Pope County's projected 2014 population, so the new land-use impacts of worker in-migration are expected to be minimal. However, key sources expect residential development to continue on the peninsula because of the availability of desirable lakefront property. As in the past, this continued residential development would be guided by the provision of roads and water service, an indirect impact of ANO's presence. The plant's operation also would result in continued economic benefits such as direct and indirect salaries and tax contributions for Pope County. But the tax benefits may be less than those previously available because of

Amendment 59, which in the mid-to-late 1980's caused reductions in tax payments on utility property. Nonetheless, ANO-1's operation would provide Pope County with economic benefits that would continue to shape land-use and development patterns in Russellville and the rest of the county through the provision of municipal services" [Reference 2, GEIS, Volume 2, Appendix C, C.4.1.5.2 Predicted Impacts of License Renewal]. Entergy Operations accepts the GEIS evaluation and no further evaluation is required.

Analysis of Impact of Refurbishment Activities on Public Schools

There are no identified major refurbishment activities required for license renewal at ANO-1 [See Section 3.2]. Therefore, no further analysis of the impact of this issue is required.

Public Water Supply - GEIS Background

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 the quality of water and sewage treatment) are substantially degraded and additional capacity is needed to meet ongoing demands for services. In general, small to moderate impacts to public utilities were observed as a result of the original construction of the case study plants. While most locales experienced an increase in the level of demand for services, they were able to accommodate this demand without significant disruption. Water service seems to have been the most affected public utility.

Public utility impacts at the case study sites during refurbishment are projected to range from small to moderate. The potentially small to moderate impact at Diablo Canyon is related to water availability (not processing capacity) and would occur only if a water shortage occurs at refurbishment time. Because the case studies indicate that some public utilities may be overtaxed during peak periods, the impacts to public utilities would be moderate in some cases, although most sites would experience only small impacts. This is a Category 2 issue [Reference 2, GEIS Section 3.7.4.5].

Analysis of Impact of the Proposed Action on Public Water Supply

The impact on public utilities attributable to population increases from the proposed action is evaluated in GEIS, Volume 2, Appendix C, Section C.4.1.4.2 (Predicted Impacts of License Renewal). The following excerpt is from that source: "…the public water system may be moderately affected because of the diminishing local water supply and increasing water usage by the plant."

License renewal is not projected to cause a noticeable effect on the Russellville water supply. Historically, the water system has used the Illinois Bayou and, on occasion, Lake

Dardanelle as a source of water. In 1997, the City of Russellville completed the construction of a new water supply source, the Huckleberry Creek Reservoir. This new reservoir significantly increased the water system storage capacity and provides residential and industrial customers in the area with a reliable supply of high quality water for many years. Plans are also being made to double the current water treatment processing capacity of 10 million gallons per day.

ANO is currently the third largest water consumer on the Russellville water system, with an average consumption of approximately 100,000 gallons per day. The facility is connected to the water system by way of a 1,000,000 gallon storage tank located north of the facility. Eighty percent of the capacity of the tank is reserved for ANO with the remaining amount assigned to meet the needs of the City of London, Arkansas.

During normal plant operations, the amount and quality of water available to ANO from the Russellville water system is adequate to meet the facility’s operational needs. During infrequent start-up periods, however, the short-term demand for water by ANO increases significantly and has caused noticeable affects on the local water distribution system. To reduce this affect, Entergy Operations completed modifications in 1997 that will now provide the facility with a supplementary source of water for start-up periods. This modification now allows water to be pumped from Lake Dardanelle, treated, and stored on-site for use during intermittent periods of high consumption. Therefore, the construction of the new water reservoir combined with the ANO facility modification, has not only minimized impacts to the public water supply system, but has also ensured that an adequate water supply will be available in the future.

4.10.4 Consideration of Alternatives for Reducing Adverse Impacts

The impacts from the proposed action on housing availability and public schools were evaluated in the GEIS and determined to be small. The impacts of the proposed action on land-use were also evaluated in the GEIS. The direct land-use impacts were found to be small, while the indirect land-use impacts (additional roads and water service) were found to be moderate. These identified impacts were found to be favorable and similar to the impacts that ANO plant operations has had on the community to date. Entergy Operations agrees with this determination, and therefore, mitigation measures for reducing or avoiding adverse environmental effects need not be considered. In addition, the construction of the new water reservoir combined with the ANO facility modification, has not only minimized impacts to the public water supply system, but has also ensured that an adequate water supply will be available in the future. Therefore, impacts to public water supply are small and mitigation measures were not considered further.

As discussed in GEIS Appendix C, Section C.4.1.3.2, one of the most significant impacts of ANO, since the start of operations in 1974, has been the benefit provided by the amount of property taxes paid by Entergy Operations to Pope County. License renewal would allow the county to continue to receive property taxes from the operating nuclear station for up to 20 additional years beyond the current license expiration.

4.11 Local Transportation Impacts

4.11.1 Requirement [10CFR51.53(c)(3)(ii)(J)]

All applicants shall 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.

4.11.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"Transportation impacts (level of service) of highway traffic generated during plant refurbishment and during the term of the renewed license are generally expected to be of small significance. However, the increase in traffic associated with the additional workers and the local road and traffic control conditions may lead to impacts of moderate or large significance at some sites. See 10CFR51.53(c)(3)(ii)(J)."

4.11.3 GEIS Background

Impacts to transportation during the license renewal term would be similar to those experienced during current operations and would be driven mainly by the workers involved in current plant operations. Based on past and projected impacts at the case study sites, transportation impacts would continue to be as small significance at all sites during operations and would be of small or moderate significance during scheduled refueling and maintenance outages. Because impacts are determined primarily by road conditions existing at the time of the project and cannot be easily forecast, a site-specific review will be necessary to determine whether impacts are likely to be small or moderate and whether mitigation measures may be warranted. This is a Category 2 issue [Reference 2, GEIS Section 4.7.3.2.].

4.11.4 Analysis of Environmental Impact

There are no identified major refurbishment activities required for license renewal at ANO–1 [See Section 3.2]. In addition, the GEIS, Volume 2, Appendix C, Section C.4.1.4.2 (Predicted Impacts of License Renewal) contains an analysis of the local transportation impacts for the area around ANO. This analysis was based on adding additional workers for refurbishment activities. The following excerpt is from that source: "…During ANO construction, when the number of in-migrants peaked at 2756 (an 8.3 percent increase in Pope County population), there were small impacts on transportation, social services, public utilities, tourism, and recreation. Projected refurbishment-related in-migration (15 percent less than construction in-migration) will increase the population 3.7 percent. Therefore, projected impacts on these public services from refurbishment will be small."

4.11.5 Consideration of Alternatives for Reducing Adverse Impacts

Since no refurbishment activities have been identified and no additional workforce has been identified as needed during the license renewal period, impacts to local transportation will continue to be small. Therefore, mitigation measures were not considered further.

4.12 Historic and Archaeological Properties

4.12.1 Requirement [10CFR51.53(c)(3)(ii)(K)]

All applicants shall assess whether any historic or archaeological properties will be affected by the proposed project.

4.12.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"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. See 10CFR51.53(c)(3)(ii)(K)."

4.12.3 GEIS Background

It is unlikely that moderate or large impacts to historic resources occur at any site unless new facilities or service roads are constructed or new transmission lines are established. However, the identification of historic resources and determination of possible impact to them must be done on a site-specific basis through consultation with the State Historical Preservation Office. The site-specific nature of historic resources and the mandatory National Historic Preservation Act consultation process mean that the significance of impacts to historic resources and the appropriate mitigation measures to address those impacts cannot be determined generically. This is a Category 2 issue [Reference 2, GEIS Section 3.7.7].

4.12.4 Analysis of Environmental Impact

ANO is located in the Arkansas River Valley. During construction of the plant, several minor sites were likely disturbed, although no records existed which indicated areas of archeological significance located within the site boundary. The Arkansas Archeological Survey Coordinating Office, the Arkansas State Parks and Tourism Commission, and the Arkansas State Historic Preservation Office were consulted during the construction and early operation of ANO for information regarding potential impacts to historic sites. In general, all sources indicated the construction and operation of ANO had only insignificant impacts on archeological sites and had no effect on historic structures listed in the Federal Register of Historic Places [Reference 1].

The SHPO was contacted [Attachment F] to identify any new information regarding sites of archeological, historical, or architectural significance on the ANO site. Although no historical or architectural sites were identified, five archeological sites of interest were reported to exist around ANO. However, none of these areas are close enough to existing facilities to warrant concern. The SHPO provided Entergy Operations with a map that identified these sites to ensure that their archeological value remains protected. Entergy Operations notifies the SHPO prior to any significant earth-moving activities in or near these areas. A formal onsite survey was not required by the SHPO [Attachment F].

To date, the construction and operation of ANO has had no significant impact to aesthetic resources of the local area. In addition, the plant's appearance has had no adverse impact on the residential or recreational land uses on Lake Dardanelle. Because no refurbishment activities have been identified for ANO-1 license renewal, no additional land is needed for the plant's use. In addition, the visible profile of the plant is not expected to change, and impacts on historic and aesthetic resources are expected to be much smaller than the insignificant impacts experienced during construction.

In addition, the SHPO was contacted [Attachment F] to identify any information regarding sites of archeological, historical, or architectural significance along the transmission lines that were constructed to support ANO-1. No historical or architectural issues were identified.

4.12.5 Consideration of Alternatives for Reducing Adverse Impacts

Continued operation of ANO-1 during the period of the renewed license will have no significant adverse impact on historic or archeological property. No refurbishment activities have been identified as being necessary to support continued operation of ANO-1 beyond the end of the existing operating license. Therefore, impacts on historic or archeological property are small.

4.13 Severe Accident Mitigation Alternatives

4.13.1 Requirement [10CFR51.53(c)(3)(ii)(L)]

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 environmental assessment, a consideration of alternatives to mitigate severe accidents must be provided.

4.13.2 Findings from Table B-1, Appendix B to Subpart A of 10CFR Part 51

"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. See 10CFR51.53(c)(3)(ii)(L).”

4.13.3 GEIS Background

The staff concluded that the generic analysis summarized in the GEIS applies to all plants and that the probability-weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to groundwater, and societal and economic impacts of severe accidents are of small significance for all plants. However, not all plants have performed a site-specific analysis of measures that could mitigate severe accidents. Consequently, severe accidents are a Category 2 issue for plants that have not performed a site-specific consideration of severe accident mitigation and submitted that analysis for Commission review [Reference 2, GEIS Section 5.5.2.5].

4.13.4 Analysis

The following sections present the SAMA analysis that was performed for ANO-1.

4.13.4.1 Methodology Overview

The methodology used to perform the ANO-1 SAMA analysis was based on the handbook used by the NRC to analyze benefits and costs of its regulatory activities, “Regulatory Analysis Technical Evaluation Handbook”, NUREG/BR-0184, January 1997, subject to ANO-1 specific considerations.

Environmental impact statements and environmental reports are prepared using a sliding scale in which impacts of greater concern and mitigative measures of greater potential value receive more detailed analysis than impacts of less concern and mitigative measures of less potential value. Accordingly, Entergy Operations used less detailed feasibility investigative and cost estimation techniques for SAMAs having disproportionately high costs and low benefits and more detailed evaluations for the most viable candidates.

Initial input for the ANO-1 SAMA benefits analysis was the ANO-1 Probabilistic Safety Assessment model. This model is the ANO-1 internal events risk model and is an updated version of the Individual Plant Examination, “Arkansas Nuclear One Unit 1 Probabilistic Risk Assessment Summary Report,” April 1993. Therefore, the SAMA analysis is based on ANO-1 modeling.

The following is a brief outline of the approach taken in the SAMA analysis:

<u>Establish the base case – Use NUREG/BR-0184 to evaluate severe accident impacts:</u>

- Offsite exposure costs – Monetary value of consequences (dose) to offsite population; use the ANO-1 PSA model to determine total accident frequency (core damage frequency and containment release frequency); Melcor Accident Consequences Code

System to convert release input to public dose; and NUREG/BR-0184 methodology to convert dose to present worth dollars (based on valuation of $2,000 per person-rem and a present worth discount factor of 7%).

- Offsite economic costs – Monetary value of damage to offsite property; use the ANO-1 PSA model to determine total accident frequency (core damage frequency and containment release frequency); MACCS2 to convert release input to offsite property damage; and NUREG/BR-0184 methodology to convert offsite property damage to present worth dollars.

- Onsite exposure costs – Monetary value of dose to workers; use NUREG/BR-0184 best estimate occupational dose values for immediate and long-term dose, then apply NUREG/BR-0184 methodology to convert dose to present worth dollars (based on valuation of $2,000 per person-rem and a present worth discount factor of 7%).

- Onsite economic costs – Monetary value of damage to onsite property; use NUREG/BR-0184 best estimate cleanup and decontamination costs, then apply NUREG/BR-0184 methodology to convert onsite property damage estimate to present worth dollars. It is assumed that, subsequent to a severe accident, the plant would not be restored to operation, therefore replacement/refurbishment costs are not included in onsite costs. Replacement power costs, unlikely to be incurred in a deregulated market, are also not included directly but are considered in the sensitivity analysis.

<u>SAMA Identification – Identify potential SAMAs from the following sources:</u>

- Severe Accident Mitigation Design Alternative analyses submitted in support of original licensing activities for other operating nuclear power plants and advanced light water reactor plants;

- NRC and industry documentation discussing potential plant improvements; and

- Documented insights provided by the ANO-1 staff.

<u>Preliminary Screening – Eliminate non-viable candidates, based upon:</u>

- SAMA improvements that modify features not applicable to ANO-1; or

- SAMA improvements that have already been implemented at ANO-1.

Final Screening of Remaining SAMAs – Using cost-benefit analysis, screen out SAMAs that do not provide an adequate level of benefit based on:

- Implementation of SAMA would require extensive plant reconstruction, or the cost of implementing SAMA would exceed the maximum possible benefit; or
  - Cost/Benefit Evaluation – Evaluate benefits and costs of implementing the SAMA:
    - Benefit calculation – Estimate benefits of implementing each SAMA individually;
    - Existing Level 2 modeling used.
    - SAMA impacts – Calculate impacts (i.e., onsite/offsite dose and damages) by manipulating the ANO-1 model to simulate revised plant risk following implementation of each individual SAMA.
    - Averted SAMA impacts – Calculate benefits for each SAMA in terms of averted consequences. Averted consequences are the arithmetic differences between the calculated impact for the base case and revised impact following implementation of each individual SAMA.
    - SAMA Benefits – Calculate total benefit for each SAMA.

  - Cost estimate – Estimate cost of implementing each evaluated SAMA. The detail of the cost estimate must be commensurate with the benefit; if a benefit is very low, it is not necessary to perform a detailed cost estimate to determine that the SAMA is not cost beneficial – expert judgement can be applied.

  - Sensitivity Analysis – Determine the effect that changing certain inputs, including averted onsite costs and discount rate, would have on the cost-benefit calculation.

  - Conclusions – Identify SAMAs that are cost beneficial, if any, and implementation plans or provide a basis for not implementing.

The Entergy Operations' SAMA analysis for ANO-1 is presented in the following sections. These sections provide a detailed discussion of the process presented above.

4.13.4.2 Establishing the Base Case

The purpose of establishing the base case is to provide the baseline for determining the risk reductions that would be attributable to the implementation of potential SAMAs. This severe accident risk, based on the ANO-1 PSA model, is calculated through use of the IPE Level 2 and the MACCS2 Level 3 model, based upon site-specific meteorology, population characteristics, and economic information.

The primary source of data relating to the base case is the ANO-1 PSA model. The ANO-1 model used is based upon the latest modeling information available for ANO-1, and uses PSA techniques to:

- Develop an understanding of severe accident behavior;
- Understand the most likely severe accident consequences;
- Gain a quantitative understanding of the overall probabilities of core damage and fission product releases; and
- Evaluate hardware and procedure changes to assess the overall probabilities of core damage and fission product releases.

The ANO-1 PSA model includes internal events (e.g., loss of feedwater event, loss of coolant accident) and is more advanced than the IPE. The ANO-1 PSA model is periodically updated as a result of:

- Equipment Performance – As data collection progresses, estimated failure rates and system unavailabilities change.
- Plant Configuration Changes – There is a time lag between changes to the plant and incorporation of those changes into the ANO-1 PSA model.
- Modeling Changes – The ANO-1 PSA model is refined to incorporate the latest state of knowledge.

The ANO-1 PSA model describes the results of the first two levels of the PSA for ANO-1. These levels are defined as follows: Level 1 determines core damage frequencies based on system analyses and human-factor evaluations; and Level 2 determines the physical and chemical phenomena that affect the performance of the containment and other radiological release mitigation features to quantify accident behavior and release of fission products to the environment.

Using the results of these analyses, the next step is to perform a Level 3 PSA analysis, which calculates the hypothetical impacts of severe accidents on the surrounding environment and members of the public. MACCS2 is used for determining the offsite impacts for the Level 3 analysis, whereas the magnitude of the onsite impacts (in terms of clean up and decontamination costs and occupational dose) are based on information provided in NUREG/BR-0184. The principal phenomena analyzed are atmospheric transport of radionuclides, mitigative actions (i.e., evacuation, condemnation of contaminated crops and milk) based on dose projection, dose accumulation by a number of pathways, including food and water ingestion, and economic costs. Input for the Level 3 analysis includes the ANO-1 core radionuclide inventory, source terms from the IPE (as applied to the ANO-1 PSA model), site meteorological data, projected population distribution (within 50-mile radius) for the year 2025, emergency response evacuation modeling, and economic data.

The Level 3 analysis looks at the source term for each of 53 different release modes associated with endstates of the containment event tree. Because the analysis is based on probabilistic risk input, the analytical results relate the frequency of an impact to the magnitude of the impact (i.e., frequency versus risk). In general, severe accidents having the greatest predicted impact have the lowest predicted probability of occurrence. Attachment G contains detailed information on the SAMAs.

Offsite Exposure Costs

The Level 3 base case analysis shows an annual offsite exposure risk of 0.55 person-rem. This calculated value is converted to a monetary equivalent (dollars) via application of the NRC's conversion factor of $2,000 per person-rem from NUREG/BR-0184. This monetary equivalent was then discounted to present value using the NRC's formula from NUREG/BR-0184:

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

where:

APE =	monetary value of accident risk avoided due to population doses, after discounting
R =	monetary equivalent of unit dose, ($2,000/person-rem)
F =	accident frequency (events/yr)
D_P =	population dose factor (person-rems/event)
S =	status quo (current conditions)
A =	after implementation of proposed action
r =	real discount rate = 7% (as a fraction, 0.07)
t_f =	years remaining until end of facility life = 20 years.

Using a 20-year period for remaining plant life and a 7% discount rate results in the monetary equivalent value of $11,908 and is presented in Table 4.13-1.

Offsite Economic Costs

The Level 3 analysis shows an annual offsite economic risk monetary equivalent of $956. Calculated values of offsite economic costs caused by severe accidents must also be discounted to present value. Discounting is performed in the same manner as for the public health risks in accordance with the following equation:

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

AOC = monetary value of accident risk avoided due to offsite property damage, after discounting

P_D =offsite property loss factor (dollars/event)

The resulting monetary equivalent of $10,290 is presented in Table 4.13-1.

<u>Onsite Exposure Cost</u>[8]

Values for occupational exposure associated with severe accidents are not derived from the ANO-1 PSA model, but, instead, are obtained from information published by the NRC in NUREG/BR-0184. The values for occupational exposure consist of "immediate dose" and "long-term dose." The best estimate value provided by the NRC for immediate occupational dose is 3,300 person-rem, and long-term occupational dose is 20,000 person-rem (over a ten-year clean-up period). The following equations are applied to these values to calculate monetary equivalents:

Immediate Dose

For a currently operating facility, NUREG/BR-0184 recommends calculating the immediate dose present value with the following equation:

Equation (1):

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

where:

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

The values used in the ANO-1 analysis are:

- R = $2,000/person rem
- r = 0.07
- D_{IO} = 3,300 person-rems /accident (best estimate)

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

[8] Calculated values presented in this and subsequent subsections were calculated using a spreadsheet and may differ slightly from values calculated from the numbers provided; this is due to rounding performed on the numbers presented in this document.

For the basis discount rate, assuming F_A is zero, the bounding monetary value of the immediate dose associated with ANO-1's accident risk is:

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

$$= 3300 * F * \$2000 * \frac{1 - e^{-.07*20}}{.07}$$

For the core damage frequency for the base case, 1.03E-05/year,

$$W_{IO} = \$730$$

Long-Term Dose

For a currently operating facility, NUREG/BR-0184 recommends calculating the long-term dose present value with the following equation:

Equation (2):

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

where:

W_{LTO} =	monetary value of accident risk avoided long-term doses, after discounting, ($)
LTO =	subscript denoting long-term occupational dose
m =	years over which long-term doses accrue

The values used in the ANO-1 analysis are:

R =	$2,000/person rem
r =	.07
D_{LTO} =	20,000 person-rem /accident (best estimate)
m =	"as long as 10 years"

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

For the basis discount rate, assuming F_A is zero, the bounding monetary value of the long-term dose associated with ANO-1's accident risk is:

$$W_{LTO} = (F_S D_{LTO_S}) R * \frac{1 - e^{-rt_f}}{r} * \frac{1 - e^{-rm}}{rm}$$

$$= (F_S \times 20000) \$2000 * \frac{1 - e^{-.07*20}}{.07} * \frac{1 - e^{-.07*10}}{.07 * 10}$$

For the core damage frequency for the base case, 1.03E-05/year,

$$W_{LTO} = \$3,181$$

Total Occupational Exposures

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

$$AOE = \Delta W_{IO} + \Delta W_{LTO} \ (\$)$$

where,

AOE= onsite exposure avoided

The bounding value for occupational exposure (AOE_B) is:

$$AOE_B = W_{IO} + W_{LTO} = \$730 + \$3181 = \$3911$$

The resulting monetary equivalent of $3,911 is presented in Table 4.13-1.

<u>Onsite Economic Costs</u>

Clean-up/Decontamination

The total cost of clean-up/decontamination of a power reactor facility subsequent to a severe accident is estimated in NUREG/BR-0184 at $1.5E+9; this same value was adopted for these analyses. Considering a 10-year cleanup period, the present value of this cost is:

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

where

PV_{CD} = present value of the cost of cleanup/decontamination

CD = subscript denoting clean-up/decontamination

C_{CD} = total cost of the cleanup/decontamination effort, $1.5E+9

m = cleanup period (10 years)

r = discount rate (7%).

Therefore:

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

where:

PV_{CD} = present value of the cost of clean-up/decontamination

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

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

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

where:

U_{CD} = total cost of clean-up/decontamination over the life of the plant

Based upon the values previously assumed:

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

Replacement Power Costs

With respect to replacement power, the rapid transition to energy deregulation makes it extremely remote and speculative that such costs would be incurred. If a nuclear plant were no longer able to sell its power in a deregulated market, one would expect the next marginal producer to replace the power at approximately the same market price. Given this expectation, consumers should not see any significant price impact, and consequently there should be no appreciable public or societal impact. Therefore, replacement power costs are not included in the onsite costs. However, a sensitivity analysis was performed that considered replacement power costs, modeled in accordance with the guidance provided in NUREG/BR-0184.

Repair and Refurbishment

It is assumed that the plant would not be repaired. However, a sensitivity analysis was performed that considered repair and refurbishment as a contributor to onsite averted costs. The model used for estimating this cost was that provided in NUREG/BR-0184 which is 20% of the long-term replacement power costs.

Total Onsite Property Damage Costs

The total averted onsite damage costs is, therefore:

$$AOSC = F * (U_{CD})$$

where:

F = Annual frequency of the event.

AOSC = averted onsite damage cost

For the core damage frequency for the base case, 1.03E-05/year,

$$AOSC = \$119{,}285$$

The resulting monetary equivalent of \$119,285 is presented in Table 4.13-1.

4.13.4.3 SAMA Identification and Screening

The NRC and the nuclear industry have documented analyses of methods to mitigate severe accident impacts for existing and new plant's designs and for in-system evaluations. Attachment G.2 lists documents from which Entergy Operations gathered descriptions of candidate SAMAs. In addition, Entergy Operations, in preparing the ANO-1 IPE, gained insight into possible ANO-1 specific improvements that could reduce severe accident risks. Table G.2-1 of Attachment G.2 lists the 169 candidate SAMAs that Entergy Operations identified for analysis and identifies the source of the information. The first step in the analysis was to eliminate non-viable SAMAs through preliminary screening.

Preliminary Screening

The purpose of the preliminary SAMA screening was to eliminate from further consideration enhancements that were not viable for implementation at ANO-1. Screening criteria include:

- Enhancements not applicable to ANO-1 (e.g., applicable only to boiling water reactors); and

- Enhancements that have already been implemented at ANO-1 (e.g., alternate diesel generator to cope with station blackout events).

Table G.2-1 of Attachment G.2 provides a brief discussion of each candidate SAMA and its disposition, whether eliminated from further consideration as not applicable, as already implemented, or designated for further analysis. Based on this preliminary screening, 80 candidate SAMAs were eliminated, and 89 of the original SAMAs were designated for further analysis.

Final Screening/Cost-Benefit Analysis

Entergy Operations estimated the costs of implementing each SAMA through the application of engineering judgment, estimates from other licensee's submittals, and site-specific cost estimates. Evaluation was performed based on a single nuclear unit implementation basis. The cost estimates did not include the cost of replacement power during extended outages required to implement the modifications, nor did they include contingency costs associated with unforeseen implementation obstacles. Estimates based on modifications that were implemented or estimated in the past were presented in terms of dollar values at the time of implementation (or estimation), and were not adjusted to present-day dollars. Therefore, the cost estimates were conservative.

Screening based on level of benefit achieved was carried out in two steps. The first step involved calculating the maximum benefit that could possibly be provided by any one SAMA or combination of SAMAs. This maximum theoretical benefit is based upon the elimination of all plant risk and equates to the previously calculated base case risk. As shown in Table 4.13-1, the monetized value of this risk is approximately $145,000. Therefore, any SAMA having an estimated single nuclear unit cost of implementation exceeding this value would not be considered cost-beneficial and was screened from further consideration.

The next step involved performing a benefits analysis on the remaining SAMAs. The methodology for determining if a SAMA is beneficial consists of determining whether the benefit provided by implementation of the SAMA exceeds the expected cost of implementation. Since ANO-1 does not have an external events PSA model, the expected cost of each unscreened SAMA was compared with twice the calculated benefit of that SAMA. Since the benefits of the SAMAs were so small, engineering judgement was used as the basis for costs. The benefit is defined as the sum of the dollar equivalents for each severe accident impact (offsite exposure, offsite economic costs, occupational exposure, and onsite economic costs). In general, if the expected cost exceeded twice the calculated benefit, the SAMA was not considered cost-beneficial.

The result of implementation of each SAMA would be a change in the ANO-1 severe accident risk (i.e., a change in frequency or consequence of severe accidents). The methodology for calculating the magnitude of these changes is straightforward. First, the ANO-1 severe accident risk after implementation of each SAMA is calculated using the same methodology as for the base case. The results of the Level 2 model were combined with the Level 3 model to calculate these post-SAMA risks. The results of the benefit analyses for each of the SAMAs are presented in Table G.2-2 of Attachment G.2. Detailed cost estimations were not required due to the small base case result.

Each SAMA evaluation was performed in a bounding fashion. Bounding evaluations were performed to address the generic nature of the initial SAMA concepts. Such bounding calculations overestimate the benefit and thus are conservative calculations. For example, one SAMA deals with installing digital large break LOCA protection; the bounding calculation to estimate the benefit of this improvement was total elimination of large breaks. Such a calculation obviously overestimates the benefit, but if the inflated benefit indicates that the SAMA is not cost-beneficial then the purpose of the analysis is satisfied.

Two types of evaluations were used in determining the benefit of the SAMAs, model requantification and importance measure analysis. Some of the SAMAs involve modification of system models; these SAMAs were evaluated by making relatively simple, bounding changes to one or more system models and quantifying the full model. This resulted in a new set of plant damage state frequencies which where analyzed to determine the impact on public risk.

An example of such an evaluation was the estimation of the benefit of less dependence of air compressors on offsite power (more diesel-driven power available for air compressors). This SAMA was evaluated in a bounding manner by modifying the fault trees such that the air compressors were not dependent on AC power; this results in an upper limit on the improvement that is possible through more reliable AC sources.

Other SAMAs were more quickly evaluated simply by examining (through importance measures) the contribution of specific components or human actions to the core damage frequency. For example, the SAMA associated with staggering the operation of high pressure injection pumps during a loss of service water event was examined in this manner. Loss of service water events contribute approximately 27% to the total core damage frequency at ANO-1. Through expert judgement it was estimated that the additional time for recovery of service water made available by staggering the operation of high pressure injection pumps would enhance the recovery potential only 10% to 20%. Based on this assessment, the benefit was estimated to be no greater than a 20% reduction in the loss of service water contribution to the total CDF.

For the cases in which the impact on risk was estimated through use of component or human action contribution to CDF, it was assumed that the benefit was proportional to the reduction in CDF. Use of this assumption is supported by the fact that the base case values for maximum attainable benefit is due primarily to onsite costs, which are proportional to CDF.

As described above for the base case, values for avoided public and occupational health risk were converted to a monetary equivalent (dollars) via application of the NRC's conversion factor of $2,000 per person-rem and discounted to present value. Values for avoided offsite economic costs were also discounted to present value. The formula for calculating net value for each SAMA is as follows:

Net value = ($APE + $AOC + $AOE + $AOSC) – COE

Where	$APE =	monetized value of averted public exposure ($)
	$AOC =	monetized value of averted offsite costs ($)
	$AOE =	monetized value of averted occupational exposure ($)
	$AOSC =	monetized value of averted onsite costs ($)
	COE =	cost of enhancement ($)

If the net value of a SAMA is negative, the cost of the enhancement is greater than the benefit and the SAMA is not cost beneficial. Because the total value for potential risk reduction at ANO-1 is small, Entergy Operations took the approach of comparing the expected cost of the SAMAs with twice the calculated benefit as a means of determining whether a more detailed cost analysis would be necessary. The expected cost of each SAMA (COE) was determined by either utilizing applicable cost estimates published in NRC submittals from other licenses or by expert judgement by knowledgeable ANO-1 staff.

The first step in the process was to review previous licensee SAMDA submittals (e.g., the Watts Bar Nuclear Plant SAMDA evaluation). If these previous submittals contained costs for a specific SAMDA, the SAMDA description was reviewed to determine if the cost estimate could reasonably be applied to ANO-1, based on ANO-1's design and licensing bases and knowledge of implementing plant modifications. If the previous licensee submittals did not contain cost estimates or if these cost estimates could not be applied to ANO-1, a review of the benefit was performed to determine whether the SAMA could be implemented for a cost equivalent to twice the benefit. Specific detailed cost estimates were not necessary to disposition the list of SAMAs. In addition, an expert panel review was performed to provide additional insights and opinion into the costs associated and benefits associated with some of the SAMAs that were clearly not cost beneficial. This expert panel also provided additional insights into the expected benefit from the SAMAs in relation to other parameters (i.e., external events, current procedures, training, etc.). The cost-benefit comparison and disposition of each remaining SAMA are presented in Table G.2-2 of Attachment G.2.

4.13.4.4 Sensitivity Analyses

NUREG/BR-0184 recommends using a 7% real (i.e., inflation-adjusted) discount rate for value-impact analysis and notes that a 3% discount rate should be used for sensitivity analysis to indicate the sensitivity of the results to the choice of discount rate. This reduced discount rate takes into account the additional uncertainties (i.e., interest rate fluctuations) in predicting costs for activities that would take place several years in the future. Analyses presented in Section 4.13.4.2 used the 7% discount rate in calculating benefits of all the unscreened SAMAs. Entergy Operations also performed a sensitivity analysis by substituting the lower discount rate and recalculating the benefit of the candidate SAMAs.

Other sensitivities were performed; each of the sensitivities resulted in an additional benefit result for each of the SAMAs analyzed in the cost-benefit analysis. In addition to the discount rate sensitivity discussed above, the sensitivities performed include:

- Calculation of the benefit assuming the baseline discount rate and assuming external events contributed an amount equivalent to internal events to the CDF.

- Calculation of the benefit assuming averted onsite costs included the cost of replacement power and assuming the baseline discount rate.

- Calculation of the benefit assuming averted onsite costs included the cost of repair/refurbishment and assuming the baseline discount rate.

- Calculation of the benefit assuming a discount rate that is realistic for Entergy Operations (15%).

The benefits calculated for each of these sensitivities are presented in Attachment G Table G.2-3.

4.13.5 Consideration of Alternatives for Reducing Adverse Impacts

Entergy Operations analyzed 169 conceptual alternatives for mitigating ANO-1 severe accident impacts. Preliminary screening eliminated 80 SAMAs from further consideration, based on inapplicability to ANO-1's design or features that have already been incorporated into ANO-1's current design and/or procedures and programs. During the final disposition, 88 remaining SAMA candidates were eliminated because the cost was expected to exceed twice their benefit or because of disproportionately high implementation costs. The remaining SAMA candidate (#129, "*Emphasize timely recirc swapover in operator training*") was found to be potentially cost beneficial. Training issues are considered to be not relevant to the license renewal process, since training is not an age-related issue. Using the 7% real discount rate recommended by NUREG/BR-0184, 88 SAMA candidates for which the evaluation has been completed were determined not to be cost-beneficial. The sensitivities performed for each of the SAMAs indicated that the results of the analysis would not change for the conditions analyzed. In summary, based on the results of this SAMA analysis, Entergy Operations discovered only one marginally cost-beneficial SAMA which is not age-related.

Table 4.13-1 Estimated Present Dollar Value Equivalent for Severe Accident at ANO-1

Parameter	Present Dollar Value ($)
Offsite population dose	$11,908
Offsite economic costs	$10,290
Onsite dose	$3,911
Onsite economic costs	$119,285
Total	$145,394

4.14 Transportation of High-Level Waste

4.14.1 Finding from 10CFR 51, Appendix B to Subpart A, Table B-1

"The impacts of transporting spent fuel enriched up to 5% uranium-235 with average burnup for the peak rod to current levels approved by NRC up to 62,000 MWd/MTU and the cumulative impacts of transporting high-level waste to a single repository, such as Yucca Mountain, Nevada are found to be consistent with the impact values contained in 10CFR51.52(c), Summary Table S-4 – Environmental Impact of Transportation of Fuel and Waste to and from One Light-Water-Cooled Nuclear Power Reactor. If fuel enrichment or burnup conditions are not met, the applicant must submit an assessment of the implications for the environmental impact values reported in 10CFR51.52."

4.14.2 Entergy Operations' Response

The NRC issued a final rule on September 3, 1999 (became effective October 4, 1999) amending 10CFR Part 51 that changed the transportation of high-level waste from a Category 2 to a Category 1 issue [Reference 34]. As a result of this Category 1 finding, license renewal applicants are not required to prepare a separate analysis of this issue as long as no new and significant information exists. The analysis in NUREG-1437, Volume 1, Addendum 1 [Reference 35] forms the technical basis for this rulemaking.

Entergy Operations is not aware of new and significant information regarding the transportation of high-level waste that would make the generic Category 1 conclusion codified by the NRC not applicable for ANO-1. In addition, ANO-1 meets the NRC criteria for fuel enrichment and burnup conditions. Therefore, an assessment of the implications for the environmental impact values reported in 10CFR51.52 need not be submitted.

4.15 Irreversible or Irretrievable Resource Commitments

4.15.1 Requirement [10CFR51.45(b)(5)]

The applicant's report shall discuss any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.

4.15.2 Entergy Operations' Response

The February 1973 Final Environmental Statement [Reference 1], prepared in connection with the issuance of the original operating license for ANO-1, evaluated the commitment of resources associated with the construction and operation of ANO-1. These materials include:

- Nuclear fuel which is spent and converted into waste radioactive material;
- Materials used in the normal maintenance of the plant;
- Elemental materials, including iron, zirconium, and aluminum, which become, either by themselves or in combinations with other materials, radioactive.

The continued operation of ANO-1 during the extended license term will result in resource commitments. These resources include materials and equipment required for plant maintenance and operation, the nuclear fuel utilized by the reactor, and ultimately, permanent onsite storage space for the spent fuel assemblies. However, the likely power generation alternatives in the event ANO-1 ceases operation on or before the expiration of the current operating license will require commitment of resources for construction of the replacement plants as well as fuel to operate the plants.

4.16 Short-Term Use Versus Long-Term Productivity

4.16.1 Requirement [10CFR51.45(b)(4)]

The applicant's report shall discuss the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity.

4.16.2 Entergy Operations' Response

The FES [Reference 1], prepared for the issuance of the original operating license for ANO-1, evaluated the balance between the short-term uses of the environment and the maintenance and enhancement of the long-term productivity associated with the construction and operation of ANO-1. This balance is now well established. Renewal of the ANO-1 Operating License and continued operation of the plant will not alter the existing balance, but it may postpone the availability of the site for other uses. Denial of the application to renew the operating license will lead to permanent shutdown of the plant and will alter the balance in a manner that depends on subsequent uses of the site.

4.17 Unavoidable Adverse Impacts

4.17.1 Requirement [10CFR51.45(b)(2)]

The applicant's report shall discuss any adverse environmental effects that cannot be avoided upon implementation of the proposed project.

4.17.2 Entergy Operations' Response

Sections 4.2 through 4.13 of this report contain the results of Entergy Operations' review and the analyses of the 12 specific analytical requirements, as required by 10CFR51.53(c)(3)(ii). These reviews take into account the information that has been provided in the GEIS, Appendix B to Subpart A of Part 51, and information specific to ANO-1.

This review and analysis did not identify any significant adverse environmental impacts associated with the continued operation of ANO-1. The evaluation of structures and components as required by 10CFR54.21 has been completed. No plant refurbishment activities, outside the bounds of normal plant component replacement and inspections, have been identified as necessary to support continued operation of ANO-1 beyond the end of the existing operating license. As a result of these reviews and analyses, Entergy Operations is not aware of any significant adverse environmental effects that cannot be avoided upon implementation of the proposed project.

4.18 Environmental Justice

4.18.1 Findings from 10CFR51, Appendix B to Subpart A, Table B-1

"The need for and the content of an analysis of environmental justice will be addressed in plant-specific reviews."

4.18.2 Background

Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low Income Populations" 59 FR 7629 (Feb. 11, 1994), requires Federal agencies to identify and address, as appropriate, "disproportionately high and adverse human health or environmental effects" from their programs, policies, and activities on minority and low-income populations. Former NRC Chairman Selin took the position that the NRC, although an independent agency, would comply with this Executive Order and would participate with an Interagency Working Group to develop implementation guidelines. The environmental justice review was performed in accordance with Attachment 4 of "NRR Office Letter No. 906, Revision 2, "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues", dated September 21, 1999 [Reference 36].

4.18.3 Environmental Impacts from the Proposed Action

As noted above, the consideration of environmental justice is required to assure that federal programs and activities will not have "disproportionately high and adverse human health or environmental effects…on minority populations and low-income populations..." Entergy Operations' analyses of the 12 specific analytical requirements defined in 10CFR51.53(c)(3)(ii) determined that the impacts from the continued operation of ANO-1 through the renewal period were insignificant. As indicated in the NRR Procedure for Environmental Justice Reviews [Reference 36], if no significant offsite impacts will occur, there can be no disproportionately high and adverse impacts on any member of the public, including minority and low-income populations. Based on the review of these issues as discussed in Sections 4.2 through 4.13, no review for environmental justice is necessary. However, the following information is presented to assist the NRC's review of this issue.

4.18.4 Description of Process used in Entergy Operations' Review-NRR Procedure for Environmental Justice Reviews

The NRR Procedure for Environmental Justice Reviews [Reference 36] was developed to provide guidance to the NRC Office of Nuclear Reactor Regulation staff on conducting environmental justice reviews. The criteria in this reference were used to determine if there was a sufficiently large enough minority or low-income population composition in the vicinity of ANO to warrant an environmental justice review. This reference requires the staff to:

1. Determine whether the regulatory action will be supported by an EIS or by an EA. When the regulatory action requires the preparation of an EIS or a supplement to an EIS, an environmental justice review must be prepared using the process discussed in paragraphs 2 through 9 below. Under most circumstances, no environmental justice review should be conducted where an EA is prepared. If it is determined that a particular action will have no significant environmental impact, then there is no need to consider whether the action will have disproportionately high adverse impacts on certain populations.

2. During the public scoping process for the EIS, include environmental justice as a discussion topic along with other topics normally addressed in the EIS scoping process. Solicit input from populations potentially affected by the action.

3. Identify the environmental impact site(s) using input from the public scoping process and the evaluation of environmental impacts for the EIS. Determine the location of environmental impact sites for all adverse human health or environmental impacts which are known to be significant or perceived as significant by groups and/or individuals (typically up to 80 kilometers or 50 miles). The size of the impact sites will vary depending upon the nature of the impacts, and should be consistent with the areas used to review environmental impacts in the EIS.

4. Determine the geographic area to be used for the comparative analysis of minority or low-income populations. The geographic area is a larger area that encompasses all the environmental impact sites (for example, a county or group of counties).

5. Determine the minority and low-income composition within a geographic area. Determine the percentage of the total population within the geographic area for each minority and low-income category. Minority is defined as Black; American Indian, Eskimo, or Aleut; Asian or Pacific Islander; other non-white; and Hispanic origin.[9] The low-income composition is determined by using the percentage of households within the geographic area that are below the poverty level. For performing environmental justice reviews, low-income is defined as being below the poverty level as defined by the Census Bureau.

6. For each environmental impact site, determine the percentage of the minority and low-income population.

[9] Note that the values for the Hispanic populations may also be included in the values for the white, black, or minority populations.

7. An environmental justice review must be performed if one of the following exists:

    a) A minority population exists if 1) the minority population of the environmental impact site exceeds 50%, or 2) the minority population percentage of the environmental impact site is significantly greater (typically 20%) than the minority population percentage in the geographic area chosen for the comparative analysis.

    b) A low-income population is considered to be present if the percentage of households below the poverty level in an environmental impact site is significantly greater (typically at least 20%) than the low-income population percentage in the geographic area chosen for the comparative analysis.

8. When minority or low-income populations exist, it must be determined if disproportionately high and adverse effects result from the proposed action.

9. Conclusions regarding whether the proposed action will have disproportionately high and adverse environmental impacts on minority or low-income populations should be clearly stated and supported with sufficient information.

4.18.5 Environmental Impact Site

As outlined in the NRR Procedure, environmental impact sites must be designated for all adverse human or environmental impacts arising from the proposed action which are known to be significant. As illustrated by the results of Entergy Operations' review of the 12 specific analytical requirements defined in 10CFR51.53(c)(3)(ii), there are no significant adverse human or environmental impacts arising from the renewal of ANO-1's operating license. Likewise, the Category 1 issues are insignificant. Accordingly, no environmental impact sites need to be designated for the purposes of an environmental justice review at ANO-1. However, to assist the NRC Staff in its review of this issue, Entergy Operations performed a review of minority and low-income population data for the ANO vicinity. Population information is shown below for a hypothetical environmental impact site defined as an area within a 10-mile (16.1 km) radius of ANO. This area was selected to be consistent with the area used for the Emergency Planning Zone at ANO.

Additional information is also provided for minority and low-income populations using a 50-mile radius environmental impact site. This area was selected as an alternative environmental impact site and coincides with the area used for the SAMA analysis [ER Section 4.13]. The population data provided for a 50-mile radius environmental impact site is less detailed than information outlined for a 10-mile radius environmental impact site. It is, however, sufficient to satisfy the objectives of the NRR Procedure for Environmental Justice Reviews.

4.18.6 Selection of Geographic Area

To determine if a minority or low-income population exists within the environmental impact site, population data within a larger area was obtained for a comparative analysis. ANO is located in the southwestern portion of Pope County near the boundaries of Johnson, Logan, and Yell Counties [Figure 4.18-1]. The geographic area for the analysis was selected to be the area composed of portions of the four counties within a 15-mile (24.2 km) radius from ANO. Comparison of the data for minority populations and low-income populations shows that the data for the 15-mile (24.2 km) radius for minority populations and for low-income households are representative of populations residing within Pope, Johnson, Logan, and Yell Counties (Tables 4.18-1 through 4.18-5).

An additional analysis of minority and low-income populations was performed using the State of Arkansas as a geographic area. Minority and low-income population data is provided for a comparative analysis with population data within the 50-mile radius environmental impact site. Again, state-wide data presented below is less detailed than information outlined for the 15-mile radius geographic area, but it is sufficient to satisfy the objectives of the NRR Procedure for Environmental Justice Reviews. The population data was based on the 1990 US Census and was obtained from the Census State Data Center/GIS Laboratory, Institute for Economic Advancement, University of Arkansas at Little Rock [Reference 37].

4.18.7 Method to Determine Block Groups within 10 and 15-Mile Radius

The U.S. Census Bureau 1990 decennial census database is the most recent source for population data at the block group level. This source of data includes the geo-referenced location for the center (or centroid) for each block group. Block groups with area centroids within the 10, 15, and 50-mile radii used in this environmental justice review were identified using ARCVIEW™ Geographic Information System software. ARCVIEW GIS was also used to extract and compile the minority and low-income population data from U.S. Census Bureau database. The information for these block groups was then reviewed with respect to the NRR criteria for minority and low-income populations.

4.18.8 Comparison of 1990 U.S. Census Data to More Recent Data

The 1990 decennial census is the most current data available for minority and low-income populations at the block group level. There is no estimated 1997 block group data available for minority and low-income populations. A comparison was performed of the minority population percentages at the block group level in the 1990 census to the 1997 census estimates of minority population percentages at the county level. As shown in Table 4.18-1, there is no significant difference between the 1990 census data and the 1997 census estimates for minority populations. No 1997 estimates of low-income populations are available at the county level. The 1990 census data also provides the most current data source for this segment of the population.

4.18.9 Minority Population Review

As noted above, two hypothetical environmental impact sites (10-mile radius and 50-mile radius) and two geographic areas (15-mile radius and the State of Arkansas) were selected for comparative analysis. Discussed below are the results of these two reviews, which indicate the minority population in the vicinity of ANO is relatively low and no environmental justice review is required.

Population data within a 10-mile environmental impact site was reviewed for any significant minority populations. Even at the block group level, census data showed low percentages of minority populations. One block group, within the municipality of Russellville located in Pope County [Figures 4.18-2 and 4.18-3], was identified which had a significant minority population (significant minority population is considered to be one that exceeded the percentage of minority population for the 15-mile radius geographic area by 20% or more). Table 4.18-3 provides the percentages of minority populations for the individual block groups within the 10-mile radius environmental impact site.

The minority population percentage within the 10-mile (16.1 km) radius environmental impact site is 5.0% and within the 15-mile geographic area is 4.1% (Table 4.18-2). Therefore, a minority population, for the purposes of an environmental justice review, does not exist because the percentage of minority population within the 10-mile (16.1 km) radius (5.0%) does not exceed the percentage of minority within the total population of the geographic area (4.1%) by 20% or more, and the percentage of minority population within the 10-mile (16.1 km) radius (5.0%) does not exceed 50%.

A minority population does not exist when a larger environmental impact site and geographic area are considered. Within a 50-mile radius of ANO, the minority population (12,207) composes 5.8% of the total population (210,198). The minority population of Arkansas (406,332) composes 17.3% of the total population in Arkansas (2,350,725). These census data do not meet the NRR criteria which would indicate a minority population exists within the 50-mile radius environmental impact site.

4.18.10 Low-Income Population Review

Two hypothetical environmental impact sites (10-mile radius and 50-mile radius) and two geographic areas (15-mile radius and the State of Arkansas) were selected for comparative analysis of low-income population data. As shown below, the percentage of low-income population in the vicinity of ANO is relatively low and no environmental justice review is required.

Table 4.18-4 compares the percentage of low-income households within the 10-mile (16.1 km) radius environmental impact site and the 15-mile (24.2 km) radius geographic area with the percentage of low-income households of Johnson County, Logan County, Pope County, and Yell County, and the State of Arkansas. No significant difference exists in the percentage of low-income populations within the total population of the 10-mile and 15-mile radii, county, or state-wide areas.

Population data within a 10-mile (16.1 km) radius environmental impact site was reviewed for significant low-income populations (households) near ANO (significant low-income population was considered to be one that exceeded the percentage of low-income population for the 15-mile geographic area by 20% or more). At the block group level, census data showed low-income populations percentages ranged from 0.0% to 43.4% (Table 4.18-5). Two block groups within the municipality of Russellville located in Pope County were identified with significant low-income populations [Figure 4.18-4 and Figure 4.18-5]. No environmental impacts were identified by which these low-income populations would be disproportionately and adversely affected by the renewal of the ANO-1 license.

The total low-income population percentage within the 10-mile (16.1 km) radius environmental impact site is 16.4% and within the 15-mile (24.2 km) radius geographic area is 16.9% (Table 4.18-4). A low-income population, for the purpose of an environmental justice review, does not exist because the low-income population of the environmental impact site does not exceed the low-income population of the geographic area by 20% or more.

A low-income population does not exist when a larger environmental impact site (50-mile radius) and geographic area (State of Arkansas) is considered. Within a 50-mile radius of ANO, the low-income population (14,922) composes 7.1% of the total population (210,198). The low-income population for Arkansas (174,877) composes 7.4% of the total population in the state (2,350,725). These 1990 census data show the low-income population within a 50-mile radius of ANO is insignificant and does not meet the NRR criteria required for an environmental justice review.

4.18.11 Conclusion

As part of its environmental assessment of this proposed action, Entergy Operations has determined that no significant off-site impacts will be created by the renewal of the ANO-1 license. This conclusion is supported by the review performed of the 12 specific analytical requirements defined in 10CFR51.53(c)(3)(ii). As the NRR Procedure for Environmental Justice Reviews recognizes, if no significant off-site impacts occur in connection with the proposed action, then no member of the public will be substantially affected. Therefore, there can be no disproportionately high and/or adverse impacts or effects on any member of the public, including minority and low-income populations, resulting from the renewal of the ANO-1 license. In such instances, the NRC does not require an environmental justice review to be performed.

Entergy Operations has also reviewed the minority and low-income populations within the environmental impact sites of 10-mile and 50-mile radii of ANO to assist the NRC in its review of the environmental justice issue. The results of the review showed that environmental justice concerns related to the proposed action (license renewal) are insignificant. No additional review is required for the proposed action at ANO-1 because the population demographics within the project area do not meet the specified criteria requiring an environmental justice review. The population near ANO does not meet these criteria because:

- the percentages of minority citizens in the two environmental impact sites do not exceed by more than 20% the percentages of the minority population within the two geographic areas ;

- the percentages of minority citizens in the environmental impact sites do not exceed 50%; and

- the percentages of the low-income population in the environmental impact sites do not exceed by more than 20% the percentages of the low-income population in the geographic areas.

Additionally, the review of environmental justice issues did not identify any minority or low-income populations having special vulnerabilities due to customs, activities, location, or dependence on particular resources that would be disproportionately and adversely affected by the renewal of the ANO-1 license.

Table 4.18-1, Comparison of Minority Data – 1990 Census Data to 1997 Estimates for Pope, Johnson, Logan, and Yell Counties

County	Total Persons	Percent White	Percent Black	Percent American Indian, Eskimo, Aleut	Percent Asian or Pacific Islander	Percent Other	Percent Hispanic Origin
Johnson County (1990)	18,221	96.8	1.7	0.6	0.4	0.5	1.2
Johnson County (1997)	21,165	97.0	1.9	0.6	0.6	N/A	2.3
Logan County (1990)	20,557	97.7	1.3	0.6	0.1	0.2	0.7
Logan County (1997)	21,245	97.6	1.6	0.6	0.2	N/A	1.4
Pope County (1990)	45,883	96.2	2.5	0.7	0.4	0.2	0.9
Pope County (1997)	51,219	95.9	2.8	0.7	0.6	N/A	2.0
Yell County (1990)	17,759	96.7	2.1	0.4	0.6	0.2	1.0
Yell County (1997)	19,089	96.0	2.8	0.5	0.7	N/A	2.1

1990 data from 1990 U.S. Census Bureau C90STF1A Database
1997 data from U.S. Census Bureau Estimates of Population of Counties by Race and Hispanic Origin: September 4, 1998

Table 4.18-2, Comparison of Minority Population Percentage – 10-Mile Radius Versus 15-Mile Radius

Area	Total Persons	Percent White	Percent Total Minority	Percent Black	Percent American Indian, Eskimo, Aleut	Percent Asian or Pacific Islander	Percent Other	Percent Hispanic Origin
Within 10 Mile (16.1km) Radius [a]	35,820	95.0	5.0	3.6	0.7	0.4	0.3	0.9
Within 15 Mile (24.2km) Radius [a]	49,692	95.9	4.1	2.7	0.7	0.4	0.3	0.8
Johnson County [b]	18,221	96.8	3.2	1.7	0.6	0.4	0.5	1.2
Logan County [b]	20,557	97.7	2.3	1.3	0.6	0.1	0.2	0.7
Pope County [b]	45,883	96.2	3.8	2.5	0.7	0.4	0.2	0.9
Yell County [b]	17,759	96.7	3.3	2.1	0.4	0.6	0.2	1.0
Johnson, Logan, Pope, & Yell Counties	102,420	96.7	3.3	2.0	0.6	0.4	0.3	0.9
Arkansas [b]	2,350,725	82.8	17.2	15.9	0.5	0.5	0.3	0.8

[a] Source of Data: U.S. Census Bureau 1990 C90STF3A Data
[b] Source of Data: U.S. Census Bureau 1990 C90STF1A Data
Note: Table 4.18-3 provides data on the percentage of minorities in the individual block groups, within the 10-mile (16.1 km) radius

Table 4.18-3, Percent of Minority Population – Block Groups within 10-Mile Radius

Block Group	County	Block Group Total Persons	Percent White	Percent Black	%American Indian, Eskimo, Aleut	Percent Asian or Pacific Islander	Percent Other	Percent Hispanic Origin
050719522.00:2	Johnson	379	96.3	0.0	1.6	1.8	0.3	0.3
050719522.00:3	Johnson	359	98.3	0.0	1.4	0.3	0.0	1.4
050839501.00:1	Logan	755	100.0	0.0	0.0	0.0	0.0	0.0
051159507.00:3	Pope	8	100.0	0.0	0.0	0.0	0.0	0.0
051159508.00:1	Pope	1,360	98.8	0.2	1.0	0.0	0.0	1.0
051159508.00:2	Pope	1,425	98.4	0.0	0.8	0.5	0.3	0.6
051159509.00:1	Pope	121	99.2	0.0	0.8	0.0	0.0	0.8
051159509.00:2	Pope	737	96.9	0.0	3.1	0.0	0.0	0.0
051159509.00:3	Pope	481	99.8	0.0	0.2	0.0	0.0	0.0
051159509.00:4	Pope	1,484	99.7	0.0	0.0	0.3	0.0	0.3
051159512.00:1	Pope	605	98.5	0.0	0.0	1.5	0.0	0.7
051159512.00:2	Pope	250	99.2	0.0	0.0	0.0	0.8	1.2
051159512.00:3	Pope	64	96.8	1.6	1.6	0.0	0.0	1.6
051159513.00:1	Pope	1,428	99.4	0.6	0.0	0.0	0.0	0.0
051159513.00:2	Pope	1,659	94.3	4.5	0.7	0.5	0.0	0.7
051159513.00:3	Pope	613	97.2	2.0	0.0	0.0	0.8	4.4
051159513.00:4	Pope	686	97.4	1.7	0.9	0.0	0.0	0.0
051159513.00:5	Pope	1,153	93.4	0.7	1.3	3.9	0.7	3.3
051159514.00:1	Pope	586	93.7	6.3	0.0	0.0	0.0	0.0
051159514.00:2	Pope	1,448	89.9	5.6	1.7	0.0	2.8	5.2
051159514.00:3	Pope	362	86.2	9.9	3.9	0.0	0.0	0.0
051159514.00:4	Pope	1,322	96.0	4.0	0.0	0.0	0.0	0.8
051159514.00:5	Pope	291	77.3	15.5	7.2	0.0	0.0	0.0
051159515.00:1	Pope	1,755	96.1	2.3	0.1	1.5	0.0	0.0
051159515.00:2	Pope	3,003	93.5	5.8	0.5	0.2	0.0	0.3
051159515.00:3	Pope	880	97.3	0.0	1.7	0.0	1.0	4.2
051159515.00:4	Pope	577	71.4	28.6	0.0	0.0	0.0	0.0
051159515.00:5	Pope	1,131	95.8	4.2	0.0	0.0	0.0	0.0
051159515.00:6	Pope	888	94.6	2.8	0.0	2.6	0.0	0.0
051159516.00:1	Pope	471	97.9	0.0	2.1	0.0	0.0	0.0
051159516.00:2	Pope	759	97.9	1.6	0.0	0.0	0.5	0.5
051159516.00:3	Pope	836	97.5	2.5	0.0	0.0	0.0	0.0
051159516.00:4	Pope	1,893	90.3	7.7	0.7	0.3	1.0	0.8
051159516.00:5	Pope	397	100.0	0.0	0.0	0.0	0.0	0.0
051159516.00:6	Pope	412	95.6	2.9	1.5	0.0	0.0	3.9
051499523.00:1	Yell	497	100.0	0.0	0.0	0.0	0.0	0.0
051499523.00:2	Yell	1,095	100.0	0.0	0.0	0.0	0.0	0.0
051499523.00:3	Yell	213	97.2	0.0	2.8	0.0	0.0	0.0
051499523.00:4	Yell	1,366	80.3	19.3	0.0	0.0	0.4	0.4
051499523.00:5	Yell	452	96.2	0.0	0.0	2.4	1.3	2.0
051499524.00:1	Yell	1,096	99.4	0.0	0.6	0.0	0.0	1.3
051499524.00:2	Yell	519	95.9	0.0	3.1	1.0	0.0	0.0
051499524.00:5	Yell	6	100.0	0.0	0.0	0.0	0.0	0.0

Source of Data: U.S. Census Bureau 1990 C90STF3A Data

Table 4.18-4, Comparison of Households Below Poverty Level Percentage – 10-Mile Radius Versus 15-Mile Radius

Area	Total Number of households	Number of households below poverty	Percent of households below poverty
Within 10 Mile (16.1km) Radius [a]	13,482	2,211	16.4
Within 15 Mile (24.2km) Radius [a]	18,460	3,124	16.9
Johnson County [b]	6,999	1,475	21.1
Logan County [b]	7,665	1,610	21.0
Pope County [b]	16,689	2,856	17.1
Yell County [b]	6,941	1,351	19.5
Johnson, Logan, Pope, & Yell Counties	38,294	7,292	19.0
Arkansas [b]	891,665	174,877	19.6

[a] Source of Data U.S. Census Bureau 1990 C90STF3A Data
[b] Table 4.18-5 provides data on the percentage of low-income households in the individual block groups within the 10 mile (16.1 km) radius.

Table 4.18-5, Percentage of Households Below Poverty Level – Block Groups within 10-Mile Radius of ANO

Block Group	County	Block Group Total Number of Households	Number of Households Below Poverty	Percent of Households Below Poverty
050719522.00:2	Johnson	147	23	15.6
050719522.00:3	Johnson	123	26	21.1
050839501.00:1	Logan	308	68	22.1
051159507.00:3	Pope	3	1	33.3
051159508.00:1	Pope	437	52	11.9
051159508.00:2	Pope	553	69	12.5
051159509.00:1	Pope	44	8	18.2
051159509.00:2	Pope	294	74	25.2
051159509.00:3	Pope	172	33	19.2
051159509.00:4	Pope	526	85	16.2
051159512.00:1	Pope	208	20	9.6
051159512.00:2	Pope	91	15	16.5
051159512.00:3	Pope	22	3	13.6
051159513.00:1	Pope	480	24	5.0
051159513.00:2	Pope	630	107	17.0
051159513.00:3	Pope	281	66	23.5
051159513.00:4	Pope	305	105	34.4
051159513.00:5	Pope	558	111	19.9
051159514.00:1	Pope	301	79	26.2
051159514.00:2	Pope	76	33	43.4
051159514.00:3	Pope	135	22	16.3
051159514.00:4	Pope	536	106	19.8
051159514.00:5	Pope	126	20	15.9
051159515.00:1	Pope	628	27	4.3
051159515.00:2	Pope	1032	74	7.2
051159515.00:3	Pope	349	16	4.6
051159515.00:4	Pope	229	95	41.5
051159515.00:5	Pope	482	47	9.8
051159515.00:6	Pope	304	13	4.3
051159516.00:1	Pope	261	26	10.0
051159516.00:2	Pope	407	55	13.5
051159516.00:3	Pope	295	34	11.5
051159516.00:4	Pope	720	224	31.1
051159516.00:5	Pope	145	23	15.9
051159516.00:6	Pope	130	14	10.8
051499523.00:1	Yell	219	39	17.8
051499523.00:2	Yell	507	68	13.4
051499523.00:3	Yell	70	11	15.7
051499523.00:4	Yell	574	145	25.3
051499523.00:5	Yell	182	46	25.3
051499524.00:1	Yell	390	80	20.5
051499524.00:2	Yell	201	23	11.4
051499524.00:5	Yell	2	0	0.0

Source of Data: U.S. Census Bureau 1990 C90STF3A Data

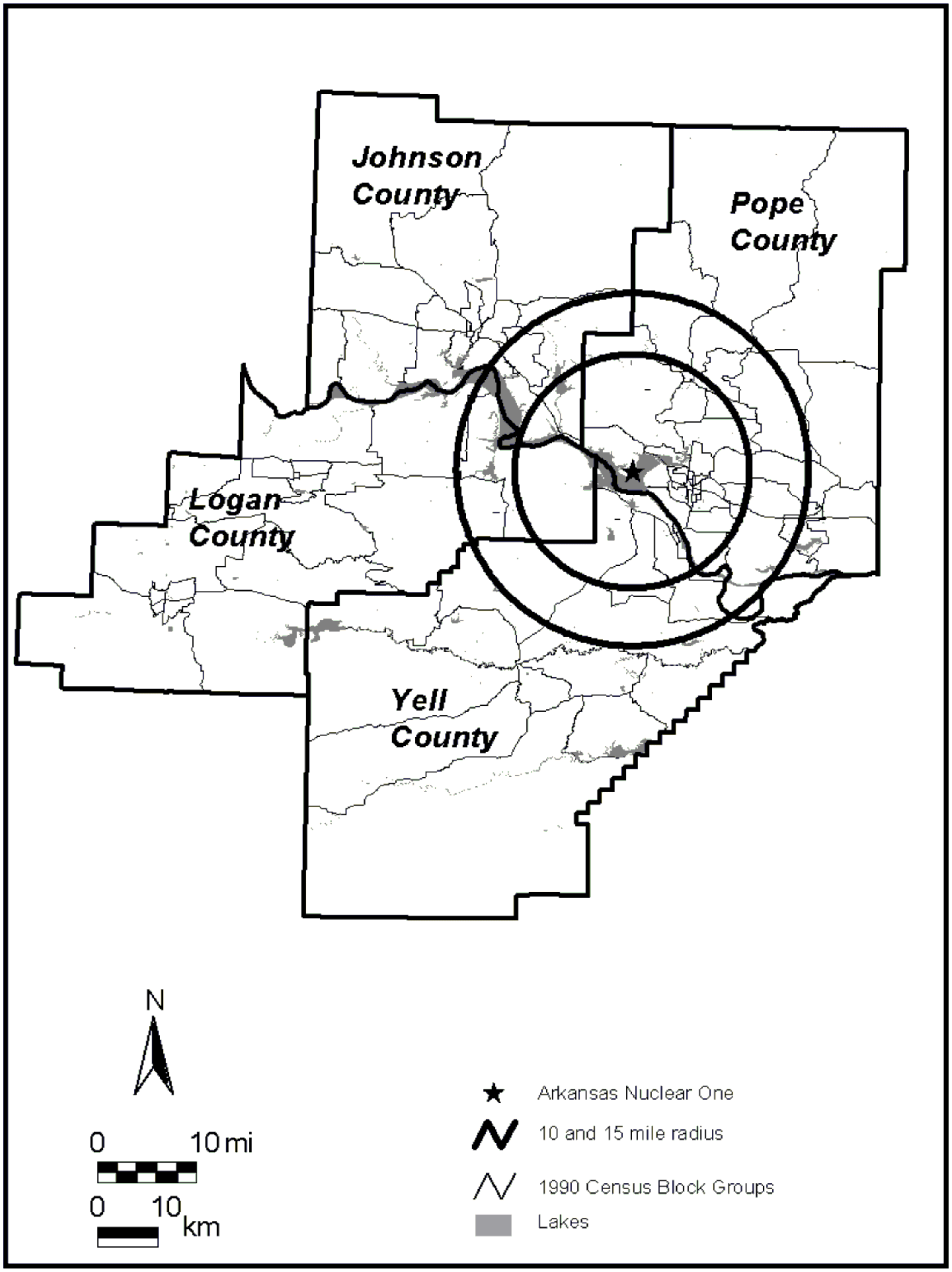

Figure 4.18-1, Census Block Groups – 10-Mile and 15-Mile Radius

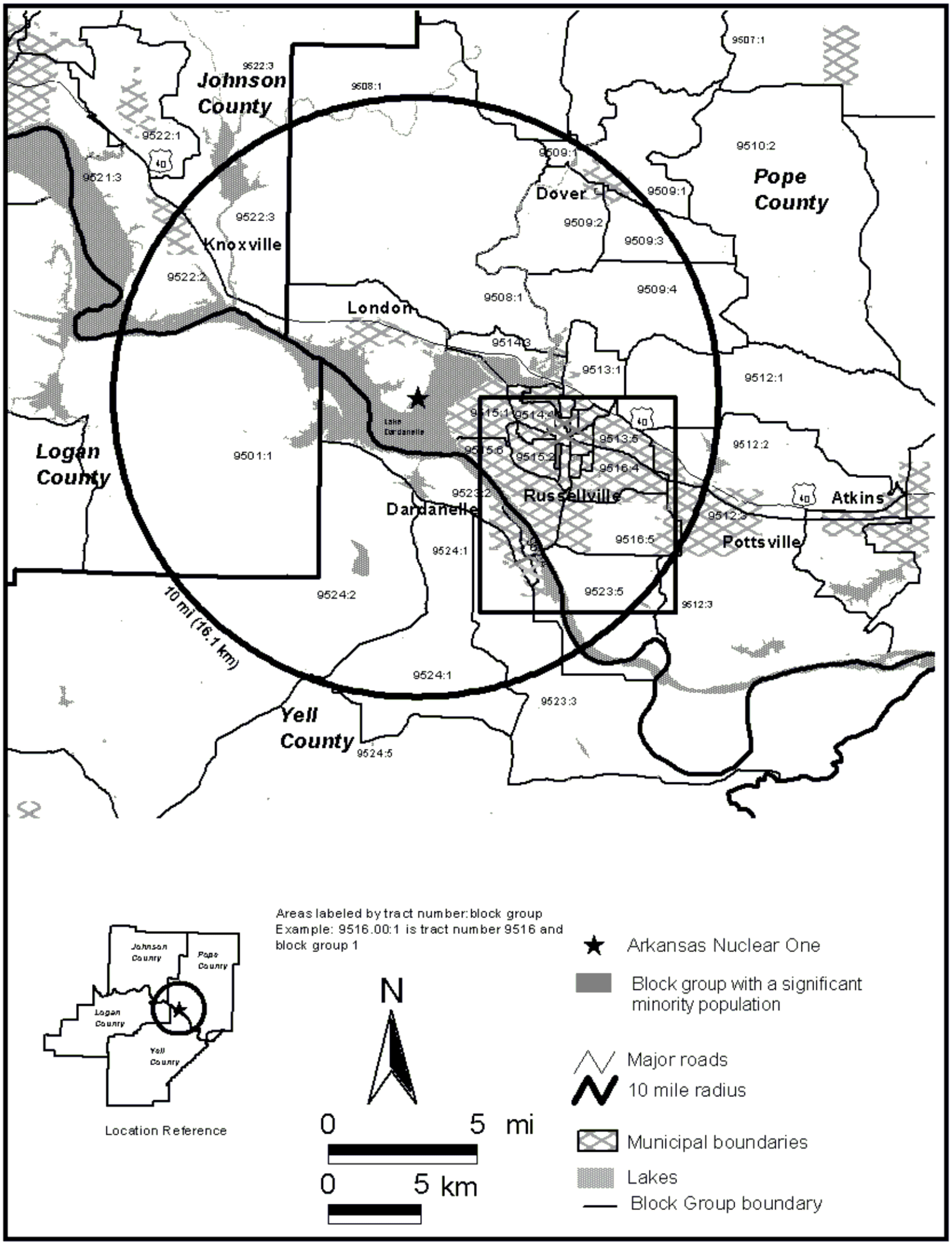

Figure 4.18-2, Block Groups – Minority Population Review

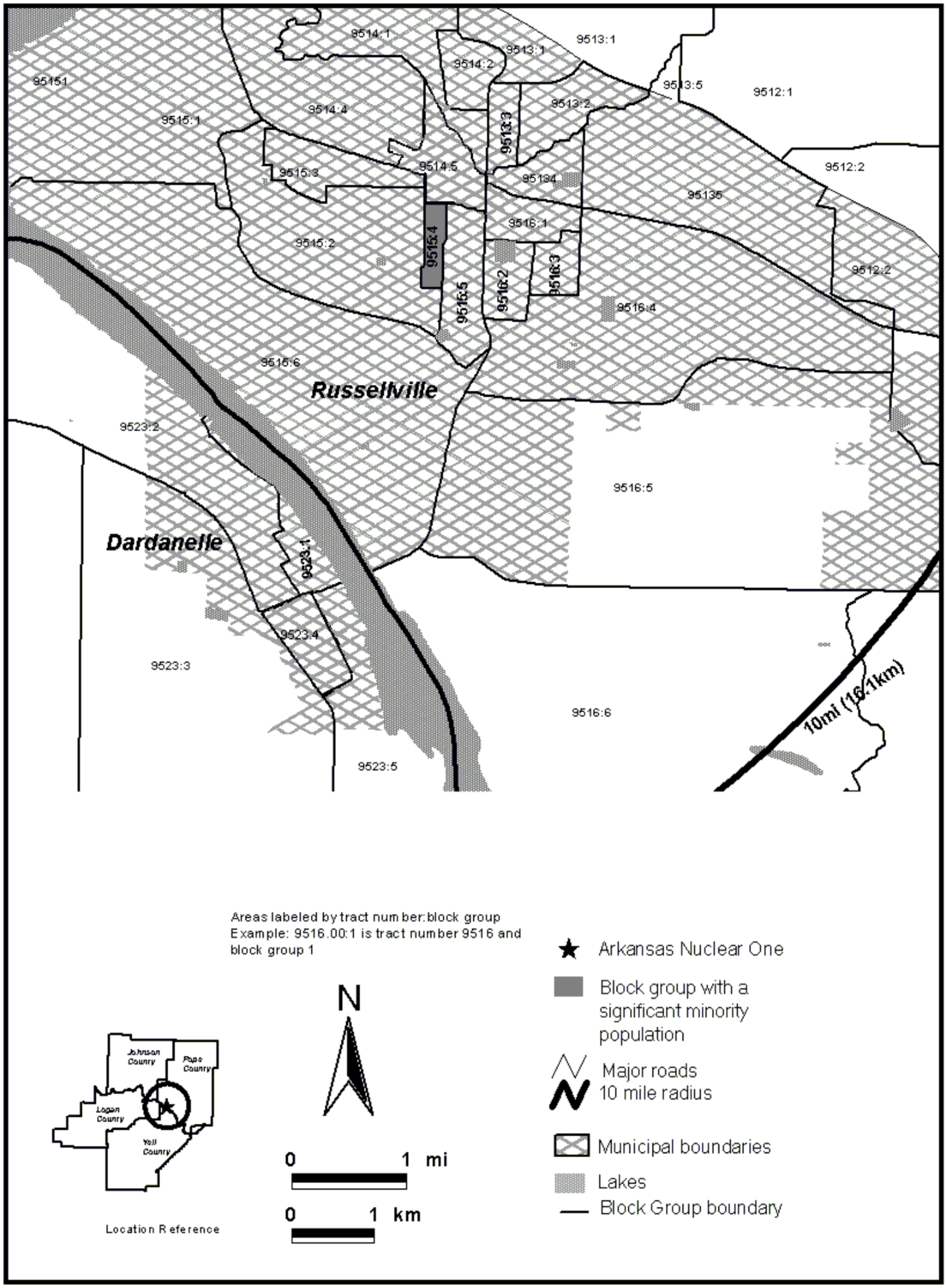

Figure 4.18-3, Census Block Groups – Minority Population Review

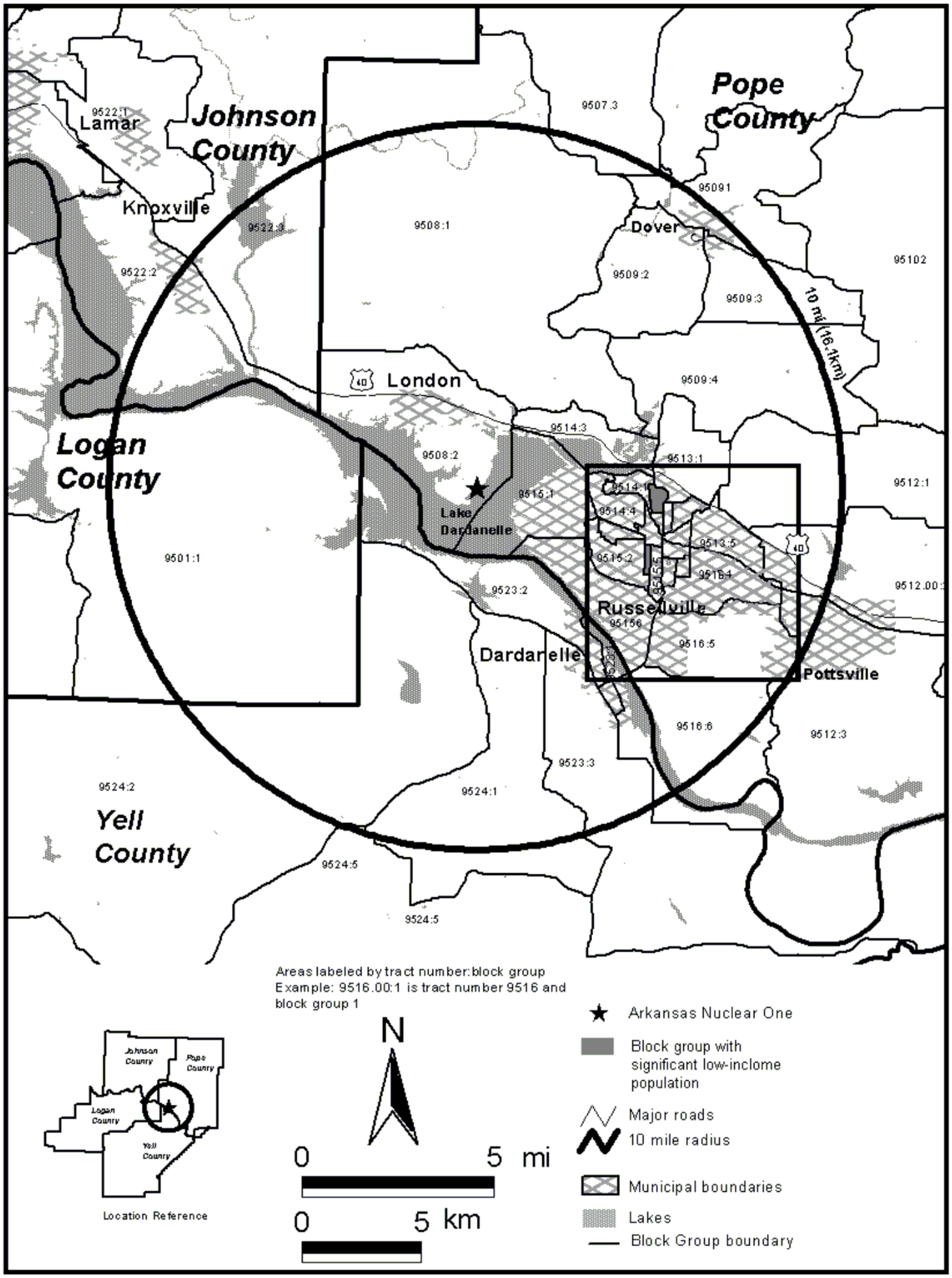

Figure 4.18-4, Block Groups – Low Income Household Review (Far-Field)

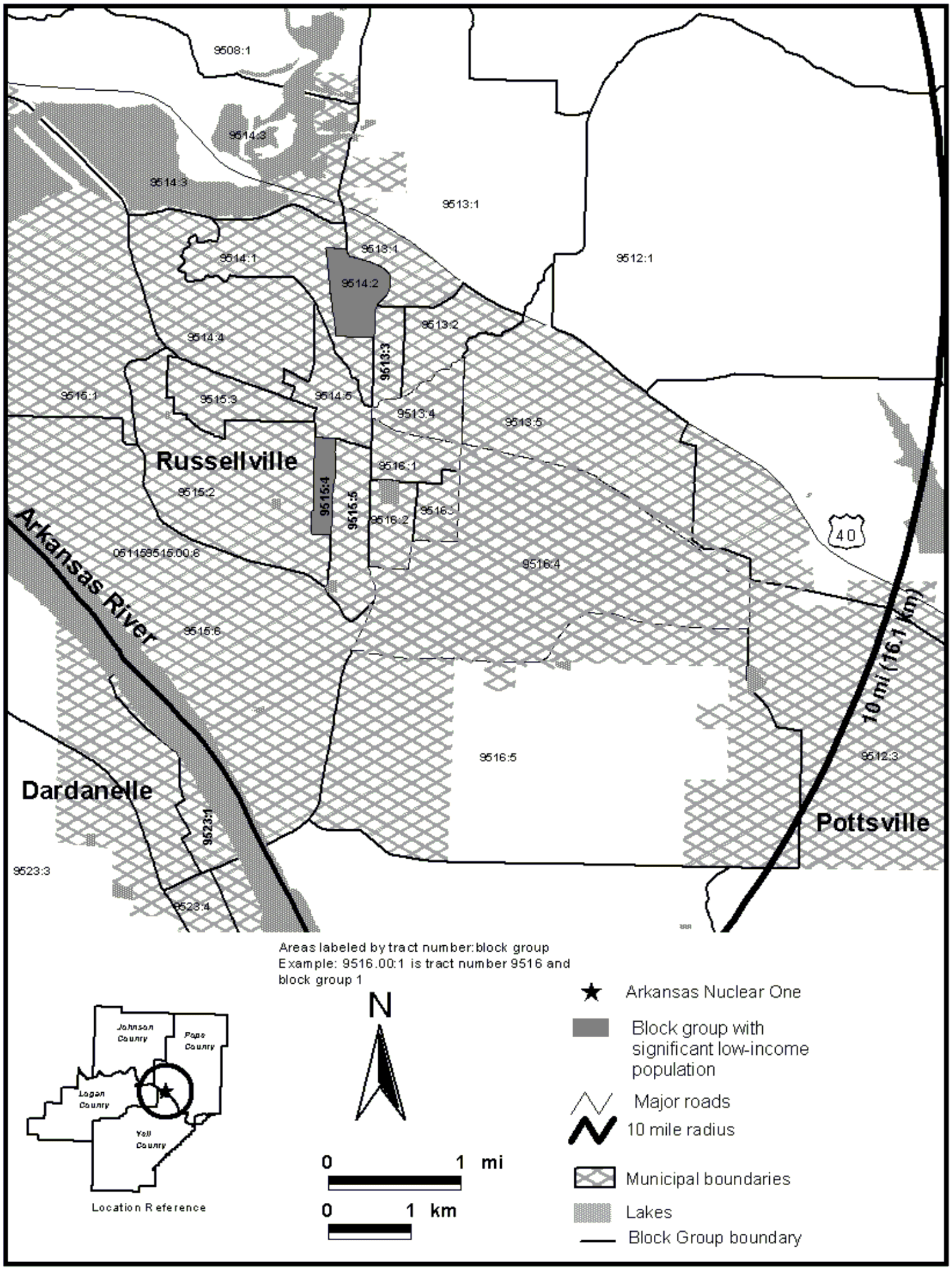

Figure 4.18-5, Block Groups – Low Income Household Review (Near-Field)

4.19 New and Significant Information

4.19.1 Requirement [10CFR51.53(c)(3)(iv)]

The environmental report must contain any new and significant information regarding the environmental impacts of license renewal of which the applicant is aware.

4.19.2 Entergy Operations' Response

Entergy Operations performed a review of the environmental issues applicable to license renewal at ANO-1. This review was performed on Category 1 issues appearing in 10CFR Part 51, Subpart A, Appendix B, Table B-1 to verify that the GEIS conclusions remained valid with respect to ANO-1. Five independent consultants (environmental, technical, and legal) assisted in the preparation and/or review of the ER. A meeting was also held with various state agencies who were provided copies of the ER for review. Based on these reviews, Entergy Operations is not aware of new and significant information regarding the plant's environment or plant operations that would make a generic conclusion codified by the NRC for Category 1 issues not applicable for ANO-1, that would alter regulatory or GEIS statements regarding Category 2 issues, or suggest any other measure of license renewal environmental impact.

ANO environmental activities receive reviews at the corporate, peer group, and site levels. The peer group consists of environmental representatives from each of the Entergy Operations' nuclear sites and corporate personnel. New requirements are identified at the corporate level, assessed for impact at the peer group level, and implemented at the site level. Also, plant activities that could potentially affect the environment will continue to receive an environmental review per ANO procedures. These reviews assess the impacts on the environment as well as any necessary changes and/or additions to the permits listed in Table 7.2-1 of this ER.

5.0 ALTERNATIVES CONSIDERED

5.1 Introduction

The NRC regulations require that an applicant's environmental report discuss alternatives to a proposed action. [10CFR51.45(b)(3)] The intent of this review is to enable the Commission to consider the relative environmental consequences of the proposed action given the environmental consequences of other activities that also meet the purpose of the proposed action, as well as the environmental consequences of taking no-action at all [Reference 2]. For the purposes of license renewal, there are only two alternatives that meet the purpose of the action: the renewal of the operating license or the decision not to renew the operating license. This section identifies the alternatives considered.

5.2 Proposed Action

The proposed action is the renewal of the operating license of ANO-1. This action would provide the opportunity for Entergy Operations to continue to operate ANO-1 through the 20-year term of the renewed license, expiring in 2034. The review of the environmental impacts as required by 10CFR51.53(c)(3)(ii) was provided in Section 4.0. Based on these reviews, Entergy Operations concludes impacts from the continued operation of ANO-1 through the license renewal period (until 2034) would be small.

5.3 No-Action Alternative

The no-action alternative to the proposed action is a decision not to renew the original operating license for ANO-1. In the event that the ANO-1 operating license is not renewed, it is expected that ANO-1 will continue to operate up to the end of the existing operating license. A decision not to seek a renewal license would necessitate the replacement of a maximum dependable output generation capacity of 836 net megawatts with some other type of generation. The environmental impacts of the no-action alternative would be the impacts associated with the type of replacement power utilized. Because the environmental impacts would be transferred from one location to another, there would be no net benefit to the no-action alternative. The environmental impacts of these various types of replacement power are discussed in Section 6.0. In addition, there would likely be adverse financial and socioeconomic impacts from the decision not to renew the license, including local unemployment, loss of local property tax revenue, and higher energy costs.

5.4 Decommissioning

Every nuclear power plant is required to submit decommissioning plans within two years following permanent cessation of operation of each reactor or at least five years before expiration of each operating license, whichever occurs first, pursuant to the requirements of 10CFR50.54(b). Plant shutdown can occur anytime during the term of the operating license, regardless of whether or not the license has been renewed. The only difference between shutting down under the present operating license and shutting down during the renewal operating license period is the timing of the decommissioning activities. As reflected in the NRC's Category 1 finding, the impacts of decommissioning at the end of 40 years of operation are not expected to differ from those of decommissioning at the end of 60 years of operation. The environmental impacts of the termination of operations and decommissioning are addressed in Section 8.4 of the GEIS [Reference 2]. In addition, NUREG-0586 [Reference 38] provides an analysis of the environmental impacts from decommissioning. The environmental impacts of the termination of operations and decommissioning of ANO-1 are expected to be comparable to those environmental impacts described in NUREG-0586 [Reference 38].

The termination of ANO-1 operation would benefit, to some degree, the water resources in the area due to the discontinuation of the thermal discharges and other industrial and low-level radioactive liquid discharges. This benefit would only exist provided that another generating facility, using the same water resources, is not located on this site in the future.

As noted in Section 4.9, the transmission lines attributable to ANO-1 (other than the transmission lines connecting the turbine building to the switchyard) are part of the Entergy transmission system and would remain in service.

The termination of the operation of ANO-1 would eliminate the production of low-level and high-level radioactive waste. The termination of plant operations could have significant adverse impacts on the economic structure and tax base of communities surrounding the plant, due to the loss of the taxes from the facility and to the loss of direct and indirect jobs associated with ANO-1.

5.5 Alternatives

As stated in NUREG-1437, Vol. 1, Section 8.1, the "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" [Reference 2]. For the purposes of the review of alternative energy sources for ANO-1, the following alternatives were not considered as reasonable replacement power:

- Wind
- Photovoltaic Cells
- Solar Thermal Power
- Hydroelectric Generation
- Geothermal
- Wood Waste (Biomass)
- Municipal Solid Waste
- Energy Crops
- Delayed Retirement of Non Nuclear Units

- Imported Power
- Conservation
- Combination of Alternatives

As discussed in more detail in Section 6.1 of this ER, these technologies were eliminated as possible replacement power alternatives for one or more of the following reasons:

- High land-use impacts - Some of the technologies listed above would require a large area of land and would thus require a green field siting plan. This would result in a greater environmental impact than continued operation of ANO-1.

- Low capacity factors - Some of the technologies identified above are not capable of producing a maximum dependable output generation capacity of 836 net MW(e) of power at high capacity factors. These generation technologies are used as peaking power sources, as opposed to base load power sources, and for this reason are unlikely resources.

- Geographic availability of the resource - Some of the technologies are not feasible because there is no feasible location in the Entergy service area.

- Emerging technology - Some of the technologies have not been proven as a reliable and cost-effective replacement of a large generation facility. Therefore, these technologies are typically used with smaller (lower MW(e)) generation facilities.

- Availability – There is no assurance of the availability of imported power. For the purposes of this review of alternatives to the proposed action, conventional coal-fired, oil and gas-fired combined cycle, and nuclear base load generating sources are considered to be currently available conventional base load technologies that would be considered to replace ANO-1 generation upon the termination of operation. The comparison of the environmental impacts of these technologies is discussed in detail in Section 6.0.

The following were considered as reasonable replacement power alternatives and are discussed in further detail in Section 6.2:

- Conventional Coal Fire Units
- Oil and Gas (Combined Cycle)
- Natural Gas (Combined Cycle)
- Nuclear Power

6.0 COMPARISON OF IMPACTS

For the purposes of the review of alternative energy sources, the following key assumptions have been made. These key assumptions are intended to simplify the evaluation, yet still allow the no-action alternative review to meet the intent of NEPA requirements and NRC environmental regulations.

- The goal of the proposed action (license renewal) is the production of at least 1000 MW(e) to replace ANO-1's maximum dependable generation capacity of 836 MW(e) base-load generation.
- The alternatives that do not meet the goal are not considered in detail.
- A reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only those electric generation sources that are technically feasible and commercially viable [Reference 2, GEIS Section 8.1].
- The time frame for the needed generation is 2014 through 2034.
- Power purchase is not considered a reasonable alternative because there is no assurance that the capacity or energy would be available.
- The three-year average annual capacity factor of ANO-1 is 89.9 percent. The capacity factor is expected to remain consistent with this value throughout the plant's operating life.
- The Commission decision regarding the issuance of the renewal operating license for ANO-1 occurs within approximately five years after the submittal of the application for renewal.

6.1 Alternatives Not Within the Range of Reasonable Alternatives

As stated in NUREG-1437, Vol. 1, Section 8.1, the "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" [Reference 2]. Commonly known generation technologies considered reasonable by NRC are listed in the following paragraphs. However, these sources have been eliminated as "reasonable alternatives" to the proposed action because the generation of 836 net MW(e) of electricity as a base-load supply utilizing these technologies is not technologically feasible.

Wind

The average annual capacity factor for this technology was estimated at 21 percent in 1995 and is projected to be 29 percent in 2010. This low capacity factor results from the high degree of intermittence of wind energy in many locations [Reference 39]. Current energy storage technologies are too expensive to permit wind power plants to serve as large base-load plants. Wind energy has a large land requirement, approximately 150,000 acres (61,000 ha) of land to generate 1000 MW(e) of electricity. This eliminates the possibility of co-locating a wind energy facility with a retired nuclear power plant. A green-field siting plan would be required. This would have a large impact upon much of the natural environment in the affected areas [Reference 2, GEIS Section 8.3.1].

Photovoltaic Cells

The average annual capacity factor for PV cells is estimated at 25 percent. The use of PV cells for base-load capacity requires very large energy storage devices that are not feasible for shortage of sufficient electricity to meet the base-load generating requirements. This is very expensive generation, which prevents it from being competitive. This technology also has a high land-use impact which, like the wind technology, results in a large impact to the natural environment. It is estimated that 35,000 acres (14,000 ha) of land would be required to generate 1000 MW(e) of electricity [Reference 2, GEIS Section 8.3.2].

Solar Thermal Power

The average capacity factor for this technology is estimated to be between 25 and 40 percent annually. This technology, like PV cells, has high capital costs and lacks base-load capability unless combined with natural gas backup. It requires very large energy storage capabilities. Based upon solar energy resources, the most promising region of the country for this technology is the West. Land-use requirements again are high, 14,000 acres (6000 ha) for 1000 MW(e), which would result in large environmental impacts to the affected area [Reference 2, GEIS Section 8.3.3].

Hydroelectric Generation

Hydroelectric generated power has an average annual capacity factor of 46 percent. The capacity factor depends, to a large degree, on a combination of head and available water flow. A large scale hydroelectric plant of l000 MW(e) would require approximately 1,000,000 acres (400,000 ha) of land, resulting in large environmental impacts. This option is not practical due to the large loss of environmental habitat [Reference 2, GEIS Section 8.3.4].

Geothermal

A geothermal electricity generating facility has an average annual capacity factor of approximately 90 percent and can be used to provide reliable base-load power. Geothermal plants may be located only in certain areas, such as the western United States, Alaska, and Hawaii, where hydrothermal reservoirs are prevalent. This technology is not widely used as base-load generation due to the limited geographic availability of the resource and the immature status of the technology [Reference 2, GEIS Section 8.3.5]. This technology is not applicable to the region where the replacement of 836 MW(e***)*** is needed. There is no feasible location for geothermal generation within the Entergy service area.

Wood Waste (Biomass)

A wood burning facility can provide base-load power and operate with an average annual capacity factor of around 70 to 80 percent and with 20 to 25 percent efficiency. The cost of the fuels required for this type of facility is highly variable and very site-specific. The rough cost for construction of this type of facility in the ANO-1 area, where the replacement of 836 MW(e***)*** is needed, is approximately $800/kW Among the factors influencing costs are the environmental considerations and restrictions which are influenced by public perceptions, easy access to fuel sources, and environmental factors. In addition, the technology is expensive and inefficient. Therefore, economics alone eliminate biomass technology as a reasonable alternative [Reference 2, GEIS Section 8.3.6].

Municipal Solid Waste

The initial capital costs for this technology are much greater than the comparable steam-turbine technology found at wood waste facilities. This is due to the need for specialized MSW handling and waste separation equipment and stricter environmental emissions controls. These facilities are typically used when landfill space is not available for handling the waste disposal needs of a community. High costs prevent this technology from being economically competitive. Thus, municipal solid waste generation is not a reasonable alternative [Reference 2, GEIS Section 8.3.7].

Energy Crops

This technology is comparable to the wood waste facilities. This technology is not currently cost competitive with fossil-fired alternatives. Energy crops are considered an emerging technology, not economically practicable, and are not a reasonable alternative to the license renewal [Reference 2, GEIS Section 8.3.8].

Delayed Retirement of Non-Nuclear Units

The delayed retirement of fossil generation sources could not be used to replace the generation capacity of 836 net MW(e) of ANO-1, since these sources are used for peaking and intermediate generation. Additionally, there is no guarantee that these fossil units could economically operate for an additional 20 years after the current decision dates. Entergy does not have plans to retire any of its base-load fossil plants. Therefore, delayed retirement of base-load fossil generation could not be used as an alternative to the license renewal. For these reasons, the delayed retirement of non-nuclear generating units is not considered as a reasonable alternative to license renewal for ANO-1.

Imported Power

Entergy currently uses purchased power contracts and/or other options. For the purposes of this evaluation, the power purchase option is not considered a reasonable replacement for the license renewal alternative. This is due to the fact that there is no assurance that sufficient capacity or energy would be available in the 2014 through 2034 time frame to replace the 836 net MW(e) base-load generation of ANO-1.

Conservation

The concept of conservation as a resource does not meet the primary NRC criterion "that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generations sources that are technically feasible and commercially viable." It is neither single, nor discrete, nor is it a source of generation. Conservation is unlike other resources in that it reduces the demand for energy as opposed to providing a source of energy to meet the demand. Although conservation has reduced the growth in demand for electricity used or needed in the country, it has not eliminated the need for new and existing generating capacity.

Combination of Alternatives

Even though individual alternatives might not be sufficient on their own to replace ANO-1 due to the small size of the resource (hydro) or lack of cost-effective opportunities (e.g., for conservation), it is conceivable that a mix of alternatives might be cost effective. For example, if some additional cost-effective conservation opportunities could be found and combined with a smaller imported power or natural gas-fired alternative, it might be possible to reduce some of the key environmental impacts of alternatives. However, it is unlikely that such a hypothetical mix could reduce the environmental impact significance level below SMALL. In comparison, the environmental impact significance level for renewing the ANO-1 license is SMALL on all dimensions.

6.2 Comparison of Environmental Impacts for Reasonable Alternatives

As stated in the GEIS, the "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" [Reference 2, GEIS Section 8.1]. Below is a discussion of the supply side alternative energy technologies that Entergy would likely utilize if the decision is made not to extend the license period for ANO-1. These alternatives are considered to be within the range of alternatives capable of replacement power for ANO-1's base-load generation. Conventional coal-fired, oil and gas-fired combined cycle, and nuclear base-load generating sources are considered to be currently available conventional base-load technologies that would be considered to replace ANO-1 generation upon its termination of operation.

These environmental impacts are for the construction and operation of these generation facilities. The impacts discussed do not include the additional environmental impacts from obtaining and transporting the fuel sources associated with these facilities. The continued operation of ANO-1 for the license extension period would result in less environmental impact than that of the replacement power which could be obtained from other reasonable generating sources, as described below, if license renewal were not pursued.

6.2.1 Conventional Coal Fired Units

The United States currently has an abundant supply of low-cost coal. For this reason, fossil-fired technology has been considered a reasonable alternative energy source. However, the Clean Air Act of 1990 has made it increasingly expensive to operate these types of facilities. The initial capital cost for construction of a conventional coal-fired unit is approximately $800/kW, and the O&M costs are approximately $3.65/MW/hr. The environmental impacts from the construction and operation of a conventional coal-fired plant are summarized in Table 6.2-1.

A trade-off of water quality impacts would be associated with a 1000 MW(e) base-load coal unit. New base-load coal units would likely utilize closed loop cooling towers that would lessen the thermal impact of rejecting heat into lakes or streams. However, evaporation from the cooling towers would still be greater than that of ANO-1's once-through cooling system. There are no low-level radioactive waste discharges to surface water associated with a coal unit.

The solid wastes generated by a conventional coal-fired plant would be fly ash, bottom ash, SCR catalyst (used for NO_x control), and SO_2 scrubber sludge/waste. A coal facility of this size would generate significant amounts of ash on an annual basis. Approximately 70 percent of this would be fly ash and 30 percent would be bottom ash, dependent on the type of coal burned, the type of emission control equipment used, etc. The SCR would generate spent catalyst material that would have high concentrations of metals that are removed from the fly ash. A new coal-fired facility would also require SO_2 scrubbers to be installed as emission control equipment. This would also result in the generation of significant amounts of scrubber sludge on an annual basis.

The largest environmental impact from this type of generation would result from the air emissions. A conventional coal-fired facility of this size would emit significant quantities of sulfur dioxide, nitrogen oxide, particulate matter, carbon monoxide, volatile organic compounds, and carbon dioxide on an annual basis. Trace elements such as mercury, arsenic, chromium, beryllium, and selenium in the form of particulates and vapor would be emitted in small quantities. This energy source is not the most economical option that exists today. For this reason, a conventional coal-fired plant would not be considered as the first choice if license renewal were not pursued for ANO-1.

The issue of "Global Warming" is an obstacle to the utilization of coal as a reliable and long-term energy source. In a draft treaty developed December 10, 1997, in Kyoto Japan, the United States agreed to reduce the emissions of greenhouse gases (including CO_2) to 7 percent below the 1990 levels. This reduction would be phased in between the years 2008 and 2012. If this treaty is ratified and the legislation is passed that requires a reduction of this magnitude, the expanded use of coal as a reliable energy source may become impracticable due to restrictions on the levels of CO_2 emitted and the expected carbon taxes or emission caps. Other obstacles to the utilization of coal as a reliable and long term energy source are the new EPA 8-hour ozone standard (which is impacted by NO_x emissions), the new EPA $PM_{2.5}$ (particulate matter with a nominal size of less than 2.5 microns), and regional haze rules (which are impacted by SO_2).

In summary, a conventional coal-fired facility could provide replacement power for ANO-1's base-load generation. However, the air quality impacts would be greater than the impacts from continued operation of ANO-1, and the continued economic use of coal is uncertain due to the "global warming" issues. As shown in Table 6.2-1, the construction of a new facility would result in greater environmental impacts than the impacts associated with the proposed action (license renewal).

6.2.2 Oil and Gas (Combined Cycle)

Oil as a resource is not considered as a stand-alone fuel because it is typically not price competitive when natural gas is readily available. The capital cost for this type of facility is roughly $380/kW, with an operation and maintenance cost of approximately $30/MW/hr when used in combination with natural gas. The environmental impacts from the construction and operation of this type of facility are detailed in Table 6.2-1.

A trade-off of water quality impacts would be associated with a 1000 MW(e) base-load oil and gas combined cycle unit. New base-load combined cycle units would likely utilize closed loop cooling towers that would lessen the thermal impact. However, evaporation from the cooling towers would still be greater than associated with ANO-1's once-through cooling system. There are no low-level radioactive waste discharges to surface water associated with a combined cycle unit.

The solid waste generated from this type of facility would be minimal. The only significant waste would be from spent SCR catalyst used for NOx control. The largest environmental impact from operating this type of facility would be from air emissions. Since it is not economical, oil would be used as an alternative fuel to gas, provided gas was available. Significant quantities of sulfur dioxide, nitrogen oxide, particulate matter, and carbon dioxide would be emitted on an annual basis when burning fuel oil. The use of oil as a stand-alone fuel source emits more CO_2 than the gas-fired alternative. The new

8-hour ozone standard, the $PM_{2.5}$ standard, regional haze rules, and the "Global Warming" issue, as discussed above, may make it difficult to use oil as a fuel source.

This alternative energy source is typically used with natural gas as the primary fuel and with oil used as a backup. Used this way, combined cycle becomes a viable alternative energy source. The environmental impacts associated with a gas-fired facility are detailed below.

6.2.3 Natural Gas (Combined Cycle)

The estimated capital cost for the construction of combined cycle gas turbines is roughly $380/kW, with an O&M cost of approximately $25/MW/hr. Note that this variable cost is largely dependent on the price of natural gas. Natural gas combined cycle units are generally considered to be the most economical of the new construction base-load generation technologies currently available. For this reason, natural gas is widely used. The environmental impacts resulting from the construction and operation of a maximum dependable output generation capacity of 836 net MW(e) combined cycle facility are summarized in Table 6.2.-1.

A trade-off of water quality impacts would be associated with a 1000 MW(e) base-load natural gas combined cycle unit. New base-load combined cycle units would likely utilize closed loop cooling towers that would lessen the thermal impact of rejecting heat into lakes or streams. However, evaporation from the cooling towers would still be greater than that of ANO-1’s once-through system. There are no low-level radioactive waste discharges to surface water associated with a combined cycle unit.

The solid waste generated from this type of facility would be minimal. The largest environmental impact would result from the air emissions. These emissions are based on burning natural gas throughout the year. This type of facility would emit nitrogen oxide, particulate matter, and carbon dioxide when burning natural gas. The new 8-hour ozone standard, $PM_{2.5}$, and regional haze rules will not be of concern with natural gas combined cycle because these units have low NOx emissions and no SO_2 emissions.

In summary, a natural gas-fired combined cycle facility would provide viable replacement power for ANO-1's base-load generation. However, the air quality impacts would be far greater than the impacts from the continued operation of ANO-1. As shown in Table 6.2-1, the construction of a new facility would result in greater environmental impacts than the impacts associated with the proposed action (license renewal).

6.2.4 Nuclear Power

The estimated capital cost for the construction of an ALWR nuclear facility is estimated at $1530/kW, and the O&M cost is approximately $3.76/MW/hr. For this reason, this technology is not economically feasible as an alternative to the continued operation of ANO-1 with a renewed license. The environmental impacts from an ALWR would be similar to the impacts that exist for ANO-1 today. However, construction of an ALWR would require a green-field site, which would have a larger impact on the environment than the license renewal option. The environmental impacts resulting from the construction and operation of a 1000 MW(e) ALWR are summarized in Table 6.2-1.

Table 6.2-1, Comparison of Environmental Impacts					
Expected Environmental Impact [a]	Renewal of ANO-1 Operating License 836 MW(e)	Conventional Coal-Fired Fossil 1000 MW(e)	Combined Cycle Fuel Oil 1000 MW(e)	Combined Cycle Natural Gas 1000 MW(e)	Advanced Light Water Reactor 1000 MW(e)
Land Use	No additional impacts	700 ha (1700) acres needed	50 ha (120 acres) needed	45 ha (110 acres) needed	200 – 400 ha (500 - 1000 acres)
Ecology	No additional impacts	Habitat loss; impingement, entrainment; waste heat to receiving water body; cooling tower drift, fogging; bird collisions	Habitat loss; impingement, entrainment; waste heat to receiving water body; cooling tower drift, fogging; bird collisions	Habitat loss; impingement, entrainment; waste heat to receiving water body; cooling tower drift, fogging; bird collisions	Habitat loss; impingement, entrainment; waste heat to receiving water body; cooling tower drift, fogging,; bird collisions
Aesthetics	No change	Visual impacts from plant structures and emissions	Visual impacts from plant structures and emissions	Visual impacts from plant structures and emissions	Visual impacts from plant structures and emissions
Water Quality Impacts from Site Construction	None	Sediment from land clearing	Sediment from land clearing	Sediment from land clearing	Sediment from land clearing
Cooling Water Consumption	No change	860,000 m^3 (700 acre-ft) water used per quad (10^{12} Btu) energy produced	860,000 m^3 (700 acre-ft) water used per quad (10^{12} Btu) energy produced	817,000 m^3 (662 acre-ft) water used per quad (10^{12} Btu) energy produced	910,000 m^3 (740 acre-ft) water used per quad (10^{12} Btu) energy produced
Regulated Water Pollutants	40CFR Part 423 - Steam Electric Guidelines + low-level radwaste discharge	40CFR Part 423 - Steam Electric Guidelines	40CFR Part 423 – Steam Electric Guidelines	40CFR Part 423 – Steam Electric Guidelines	40CFR Part 423 – Steam Electric Guidelines + low-level radwaste discharge
Air Quality	Very little CO_2 or regulated pollutants	Emissions of CO_2, regulated pollutants, more than other technologies; also radionuclides	Emissions of CO_2, SO_2 and NO_x, regulated pollutants, radionuclides less than coal	Emissions of CO_2 and NO_x, regulated pollutants, radionuclides less than coal	Very little CO_2 or regulated pollutants
Waste	Spent fuel, low-level waste, mixed waste	Large amounts of fly ash, scrubber sludge and other solid waste	Moderate amounts of scrubber waste (less than coal) and particulates	Some solid waste	Spent fuel, slightly more mixed waste and low-level waste than license renewal
Human Health	Substantial public health improvement compared with conventional fossil plant; safety risks to workers	Public risks (cancer, emphysema) from inhalation of toxics and particulates; safety risks to workers	Some public risks (cancer, emphysema) from inhalation of toxics and particulates; safety risks to workers	Public risks (cancer, emphysema) from inhalation of toxics and particulates; safety risks to workers	<1% of natural radiation sources; safety risks to workers
Socioeconomic	Moderate employment and tax revenue	250 workers – moderate long term economic community benefits	200 workers – moderate long term economic, community benefits	150 workers – moderate long term economic, community benefits	700 workers – substantial long term economic, community benefits
Cultural	No change	Relatively small unless important site-specific resources affected by plant or transmission lines	Relatively small unless important site-specific resources affected by plant or transmission lines	Relatively small unless important site-specific resources affected by plant or transmission lines	Relatively small unless important site-specific resources affected by plant or transmission lines

NOTES:

a = Based on NUREG-1437, Vol. 1, Table 8.2

6.3 Proposed Action Versus No-Action

The proposed action is the renewal of the ANO-1 operating license. The ANO-1 specific review of the twelve specific analytical requirements, as required by 10CFR51.53(c)(3)(ii), concluded that the impacts to the environment from the continued operation of ANO-1 through the license renewal period (until 2034) would be small.

The no-action alternative to the proposed action is the decision not to pursue renewal of the operating license for ANO-1. The environmental impacts of the no-action alternative would be the impacts associated with the construction and operation of the type of replacement power utilized. In effect, the environmental impacts would be transferred from being limited to the impacts of the continued operation of ANO-1, to the environmental impacts associated with the construction and operation of a new generation facility. Therefore, the no-action alternative would not have any net environmental benefits.

The environmental impacts associated with the proposed action (the continued operation of ANO-1) were compared to the environmental impacts from the no-action alternative (the construction and operation of other reasonable sources of electricity generation). Entergy believes this comparison shows that the continued operation of ANO-1 would produce fewer significant environmental impacts than the no-action alternative. There are significant differences in the impacts to air quality impacts and land-use impacts between the proposed action and the reasonable alternative generation sources. In addition, there would likely be adverse socioeconomic impacts to the area around ANO-1 from the decision not to pursue the license renewal, including local unemployment, loss of local property tax revenue, and higher energy costs.

The United States civilian nuclear power plants represent close to 20 percent of the nation's energy supply. The average age of U.S. commercial nuclear plants is between 20 and 25 years. Currently, the operating license of thirteen plants representing 11,700 MW(e) will expire in 2014. Early closure of nuclear facilities facing regulatory and economic uncertainties has resulted in the loss of approximately 6,000 MW(e) of emission free generating capacity over the past eight years. Making the decision to renew the operating license early in the life of the plant improves the economics of the remaining capital cost recovery and lengthens the time available to accumulate decommissioning funds [Reference 40].

The Joint DOE-Electric Power Research Institute Strategic Research and Development Plan to Optimize US Nuclear Power Plants states that "... nuclear energy was one of the prominent energy technologies that could contribute to alleviate global climate change and also help in other energy challenges including reducing dependence on imported oil, diversifying the U.S. domestic electricity supply system, expanding U.S. exports of energy technologies, and reducing air and water pollution." The Department of Energy agreed with this perspective and stated that "...it is important to maintain the operation of the current fleet of nuclear power plants throughout their safe and economic lifetimes"

[Reference 40]. The renewal of the ANO-1 operating license is consistent with these goals.

6.4 Summary

The proposed action is the renewal of the ANO-1 operating license. The proposed action would provide a maximum dependable generation capacity of at least 836 net MW(e) of base-load power through 2034. The results of the review of alternatives to the proposed action are summarized in Table 6.2-1. The environmental impacts of the continued operation of ANO-1 through 2034 are less than those impacts associated with the best case assessed among reasonable alternatives. This is primarily due to the air emissions associated with the alternatives that do not exist with ANO-1. As previously discussed and as shown in Table 6.2-1, the continued operation of ANO-1 would create significantly less environmental impact than the construction and operation of new base-load generation capacity. Finally, the continued operation of ANO-1 will have a significant positive economic impact on the communities surrounding the station.

7.0 STATUS OF COMPLIANCE

7.1 Requirement [10CFR51.45(d)]

"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 that have been imposed by Federal, State, regional, and local agencies having responsibility for environmental protection."

7.2 Environmental Permits

Table 7.2-1 lists the environmental permits held by ANO and the compliance status of these permits. These permits will be in place as appropriate throughout the period of extended operation given their respective renewal schedules. Other than routine renewals required at frequencies specified by the permits in Table 7.2-1, no state, federal, or local environmental permits have been identified as being required for re-issuance to support the extension of the ANO-1 operating license. In addition, since ANO is not located in a municipality, no zoning or land-use restrictions apply. Also, ANO is in compliance with the permits listed in Table 7.2-1

Table 7.2-1, Arkansas Nuclear One Environmental Permits and Compliance Status

ANO Environmental Permits	**Federal Act**	**Permitting Agency**	**Date Permit Issued/Expires**
National Pollutant Discharge Elimination System Permit AR0001392	FWPCA Section 402	Arkansas Department of Environmental Quality	11/01/97 10/31/02
Air Permit 0090-AR-2	Clean Air Act - Section 112	Arkansas Department of Environmental Quality	11/29/94 No exp. date
Water Use Registration No. 4124	Not Applicable	Arkansas Soil and Water Conservation Commission	No issuance date No exp. date
Section 404 Permit 00241-5	Clean Water Act – Section 404	Department of Army/Corps of Engineers	03/27/97 No exp. date
Petroleum Storage Tank Registration (Facility 58000008)	RCRA Subtitle I	Arkansas Department of Environmental Quality	07/01/95 07/31/00
Petroleum Storage Tank Registration (Facility 58000009)	RCRA Subtitle I	Arkansas Department of Environmental Quality	07/01/95 07/31/00
Hazardous Materials Certificate of Registration	Hazardous Materials Transportation Act	Department of Transportation	06/30/99 06/30/00
Dardanelle Water Use Agreement Contract No. DACW03-71-0002	Title 10 USC Section 2668	Department of Army/Corps of Engineers	11/03/72 No exp. date
Nationwide Permit No. 00241-6	Rivers and Harbors Act – Section 10	Department of Army/Corps of Engineers	09/30/99 09/30/01

7.3 Environmental Permits - Discussion of Compliance

Station personnel are primarily responsible for monitoring and ensuring that ANO is in compliance with all of its environmental permits and applicable regulations. Sampling results are submitted to the appropriate agency. ANO has an excellent record of compliance with its environmental permits, including monitoring, reporting and operating within specified limits.

ANO has three ponds (lagoons) for treating domestic sewage wastewater and one emergency cooling pond for auxiliary cooling located on-site. These ponds are regulated under NPDES Permit AR0001392.

Entergy Operations has measures in place to ensure those environmentally sensitive areas or species of concern are adequately protected during site operations and project planning [Reference 41]. These measures include an environmental evaluation checklist and also establish controls and methods for evaluating potential environmental affects from plant operations and project planning. Therefore, planned projects or changes in plant operations would be required to undergo an environmental evaluation prior to implementation, with appropriate permits obtained as necessary.

Maintenance activities along transmission line right-of-ways are controlled through contracts established between Entergy and the contractor. The contract outlines contractors responsibilities regarding obtaining appropriate federal, state or local permits, including abiding with all applicable environmental laws. The primary management method used along the Entergy transmission line right-of-ways is mechanical clearing, with herbicide application only used minimally.

7.4 Other Licenses

The following additional licenses are listed:

Facility Operating License No. DPR-51 for ANO-1, Docket #50-313
Facility Operating License No. NPF-6 for ANO-2, Docket #50-368
Independent Spent Fuel Storage Installation Docket #72-13

8.0 REFERENCES

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2. NUREG-1437, Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants, Final Report, May 1996

3. Arkansas Water Quality Inventory Report, Arkansas Department of Pollution Control and Ecology, Little Rock, AR, 1994

4. Arkansas Water Quality Inventory Report, Arkansas Department of Pollution Control and Ecology, Little Rock, AR, 1996

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6. Regional Population 2000 – 2030 Projections, ANO-1 Level 3 Model Preparation, Prepared by Scientech, September 13, 1999

7. Arkansas Nuclear One - Unit 1, License Renewal Application

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31. Personal communication with Charles McGrew, Director of Communicable Diseases, Arkansas State Board of Health on August 31, 1997

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38. NUREG-0586, Generic Environmental Impact Statement on Decommissioning Nuclear Facilities, August 1988

39. DOE/EIA-0561, *Renewable Resource in the U.S. Electricity Supply*, U.S. Department of Energy, Energy Information Administration, Washington, D.C., February 1993

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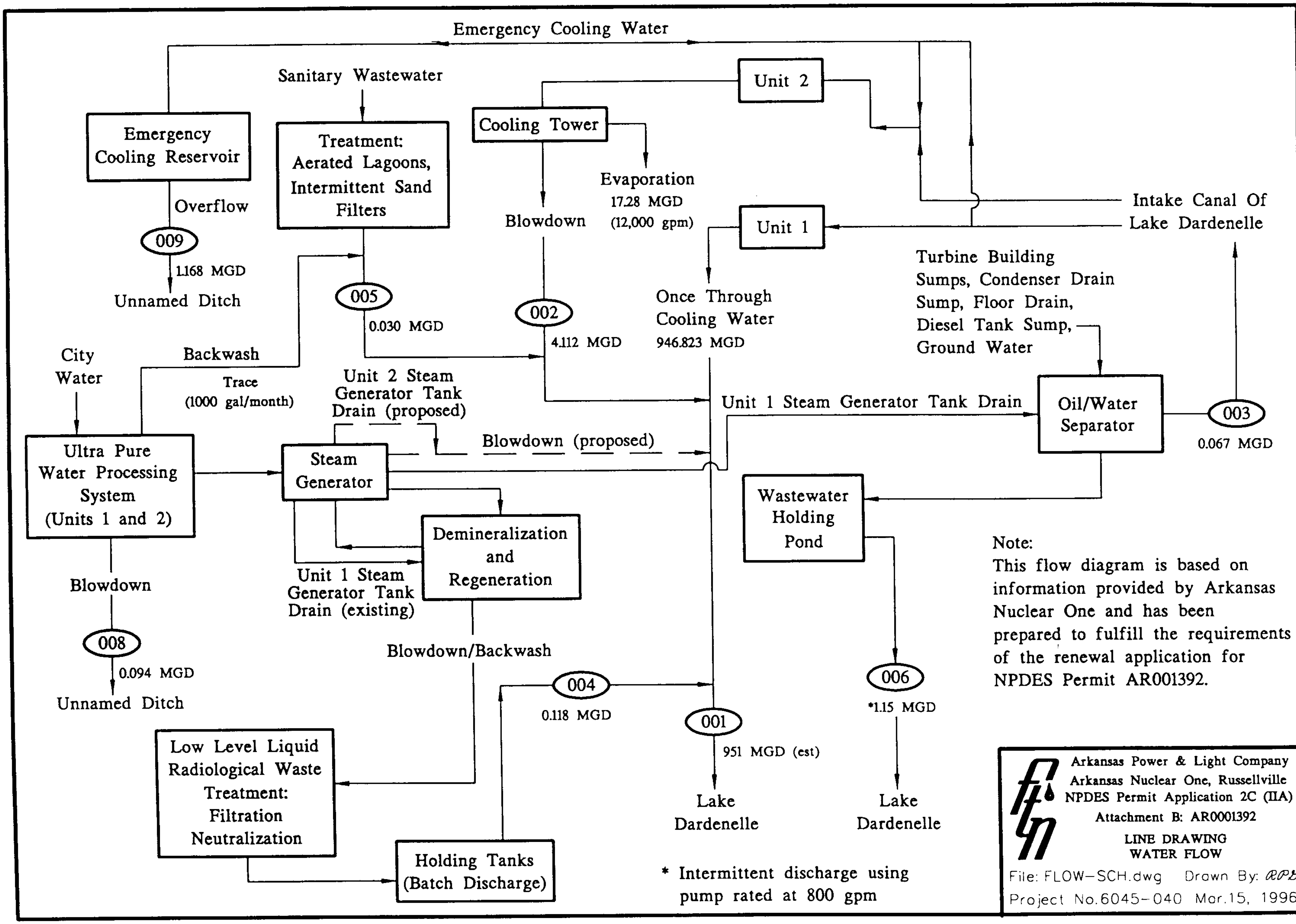
41. Entergy Company Procedure LI-101, 10CFR50.59 Review Program

Attachment A

Water Flow Diagram



Emergency Cooling Water
Sanitary Wastewater
Unit 2
Cooling Tower
Emergency Cooling Reservoir
Treatment: Aerated Lagoons, Intermittent Sand Filters
Evaporation
17.28 MGD
(12,000 gpm)
Blowdown
Unit 1
Intake Canal Of Lake Dardenelle
Overflow
009
1.168 MGD
Unnamed Ditch
005
0.030 MGD
002
4.112 MGD
Once Through Cooling Water
946.823 MGD
Turbine Building Sumps, Condenser Drain Sump, Floor Drain, Diesel Tank Sump, Ground Water
City Water
Backwash
Trace
(1000 gal/month)
Unit 2 Steam Generator Tank Drain (proposed)
Unit 1 Steam Generator Tank Drain
Oil/Water Separator
003
0.067 MGD
Blowdown (proposed)
Ultra Pure Water Processing System (Units 1 and 2)
Steam Generator
Wastewater Holding Pond
Demineralization and Regeneration
Unit 1 Steam Generator Tank Drain (existing)
Blowdown
008
0.094 MGD
Unnamed Ditch
Blowdown/Backwash
004
0.118 MGD
001
951 MGD (est)
006
*1.15 MGD
Lake Dardenelle
Lake Dardenelle
Low Level Liquid Radiological Waste Treatment: Filtration Neutralization
Holding Tanks (Batch Discharge)
* Intermittent discharge using pump rated at 800 gpm
Note:
This flow diagram is based on information provided by Arkansas Nuclear One and has been prepared to fulfill the requirements of the renewal application for NPDES Permit AR001392.
Arkansas Power & Light Company
Arkansas Nuclear One, Russellville
NPDES Permit Application 2C (IIA)
Attachment B: AR0001392
LINE DRAWING
WATER FLOW
File: FLOW-SCH.dwg Drawn By:
Project No.6045-040 Mar.15, 1996

Attachment B

NPDES Permit Number AR0001392, dated September 30, 1997

I mit number: AR0001392

AUTHORIZATION TO DISCHARGE UNDER THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM AND THE ARKANSAS WATER AND AIR POLLUTION CONTROL ACT

In accordance with the provisions of the Arkansas Water and Air Pollution Control Act (Act 472 of 1949, as amended, Ark. Code Ann. 8-4-101 et seq.), and the Clean Water Act (33 U.S.C. 1251 et seq.),

Arkansas Nuclear One
1448 S.R. 333
Russellville, AR 72801

is authorized to discharge from a facility located at

Latitude: 35° 18' 49"; Longitude: 93° 13' 32"

approximately 1.5 miles south of I-40 and 3.5 miles northwest of the City of Russellville in Sections 27, 28, 33, and 34, Township 8 North, Range 21 West in Pope County, Arkansas.

to receiving waters named:

Outfall 001: Latitude: 35° 18' 31"; Longitude: 93° 13' 50"
Outfall 002: Latitude: 35° 18' 36"; Longitude: 93° 14' 03"
Outfall 003: Latitude: 35° 18' 34"; Longitude: 93° 13' 43"
Outfall 004: Latitude: 35° 18' 37"; Longitude: 93° 13' 48"
Outfall 005: Latitude: 35° 18' 32"; Longitude: 93° 14' 12"
Outfall 006: Latitude: 35° 18' 28"; Longitude: 93° 13' 49"
Outfall 007: Latitude: 35° 18' 28"; Longitude: 93° 14' 20"
Outfall 008: Latitude: 35° 18' 38"; Longitude: 93° 13' 54"
Outfall 009: Latitude: 35° 18' 49"; Longitude: 93° 14' 10"

Lake Dardanelle, an impoundment of the Arkansas River(Outfalls 001 through 007) and an unnamed ditch then to Lake Dardanelle (Outfalls 008 and 009)in Segment 3F of the Arkansas River Basin.

in accordance with effluent limitations, monitoring requirements, and other conditions set forth in Parts I, II (Version 2), III, and IV (Version 2) hereof.

This permit shall become effective on November 1, 1997

This permit and the authorization to discharge shall expire at midnight, October 31, 2002

Signed this 30th day of September, 1997

Chuck C. Bennett
Chief, Water Division
Arkansas Department of Pollution Control and Ecology

SECTION A. FINAL EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS: OUTFALL 001-once through cooling water, previously monitored effluent from outfalls 002, 004, 005, and 007, and unit 2 steam generator tank drain.

During the period beginning on the effective date and lasting through date of expiration , the permittee is authorized to discharge from outfall serial number 001. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	**Discharge Limitations**				**Monitoring Requirements**	
	Mass (lbs/day)		Other Units (specify)		Measurement	Sample
	Monthly Avg	Daily Max	Monthly Avg	Daily Max	Frequency	Type
Flow (MGD)+	N/A	N/A	N/A	N/A	Continuous	Record***
Total Residual Oxidants*	N/A	158.6	N/A	0.2 mg/l	Once/week	Grab
Oil and Grease (O&G)+++	N/A	N/A	10 mg/l	15 mg/l	Once/week	Grab
Temperature++	N/A	N/A	105 °F	110 °F	Continuous	Record
Chronic Biomonitoring**	N/A	N/A	N/A	N/A	Once/quarter	24-hr composite
pH+++	N/A	N/A	Minimum 6 s.u.	Maximum 9 s.u.	Once/week	Grab

+ Report monthly average and daily maximum as MGD.
++ Instantaneous Maximum. See Conditions No. 7 and 14 of Part III.
+++ See Condition No. 5 of Part III.
* See Condition No. 9 of Part III.
** See condition No. 3 of Part III.
*** See Condition No. 2 of Part III.

There shall be no discharge of distinctly visible solids, scum or foam of a persistent nature, nor shall there be any formation of slime, bottom deposits or sludge banks.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at the outfall 001.

SECTION A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS: INTERNAL OUTFALL 002-Cooling tower blowdown (Unit 2)

During the period beginning on the effective date and lasting through date of expiration, the permittee is authorized to discharge from outfall serial number 002. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	**Discharge Limitations**				**Monitoring Requirements**	
	Mass (lbs/day)		Other Units (specify)		Measurement Frequency	Sample Type
	Monthly Avg	Daily Max	Monthly Avg	Daily Max		
Flow (MGD)+	N/A	N/A	N/A	N/A	Daily	Totalizing Meter
Free available oxidants(FAO)*	0.75	1.88	0.2 mg/l	0.5 mg/l	Once/week	Grab
Zinc, Total++	N/A	N/A	1.0 mg/l	1.0 mg/l	Once/month	24-hr composite
pH	N/A	N/A	Minimum 6 s.u.	Maximum 9 s.u.	Once/month	Grab

\+ Report monthly average and daily maximum as MGD.
++ When discharging from the cooling tower blowdown. See Part III, Condition No. 4.
* See Part III, Condition No. 8.

There shall be no discharge of distinctly visible solids, scum or foam of a persistent nature, nor shall there be any formation of slime, bottom deposits or sludge banks.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at the outfall 002.

SECTION A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS: OUTFALL 003-Oil/water separator

During the period beginning on the effective date and lasting through date of expiration, the permittee is authorized to discharge from outfall serial number 003. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	**Discharge Limitations**				**Monitoring Requirements**	
	Mass (lbs/day)		Other Units (specify)		Measurement	Sample
	Monthly Avg	Daily Max	Monthly Avg	Daily Max	Frequency	Type
Flow (MGD)+	N/A	N/A	N/A	N/A	Daily	Totalizing Meter
Total Suspended Solids (TSS)	N/A	N/A	30 mg/l	100 mg/l	Once/month	Grab
Oil and Grease (O&G)	N/A	N/A	10 mg/l	15 mg/l	Once/month	Grab
pH	N/A	N/A	Minimum 6 s.u.	Maximum 9 s.u.	Once/month	Grab

\+ Report monthly average and daily maximum as MGD.

There shall be no discharge of distinctly visible solids, scum or foam of a persistent nature, nor shall there be any formation of slime, bottom deposits or sludge banks.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at the outfall 003, following the final treatment unit.

SECTION A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS: INTERNAL OUTFALL 004-Low volume wastes*

During the period beginning on the effective date and lasting through date of expiration, the permittee is authorized to discharge from outfall serial number 004. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	**Discharge Limitations**				**Monitoring Requirements**	
	Mass (lbs/day)		Other Units (specify)		Measurement	Sample
	Monthly Avg	Daily Max	Monthly Avg	Daily Max	Frequency	Type
Flow (MGD)+	N/A	N/A	N/A	N/A	Once/discharge	Calculate
Total Suspended Solids (TSS)	N/A	N/A	30 mg/l	100 mg/l	Once/month	Grab
Oil and Grease (O&G)	N/A	N/A	15 mg/l	20 mg/l	Once/month	Grab
pH	N/A	N/A	Minimum 6 s.u.	Maximum 9 s.u.	Once/month	Grab

\+ Report monthly average and daily maximum as MGD.
* See Conditions No. 10 and 13 of Part III.

There shall be no discharge of distinctly visible solids, scum or foam of a persistent nature, nor shall there be any formation of slime, bottom deposits or sludge banks.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at the outfall 004, following the final treatment unit.

SECTION A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS: INTERNAL OUTFALL 005- treated sanitary wastewater and backwash water from ultra pure water system*

During the period beginning on the effective date and lasting through date of expiration, the permittee is authorized to discharge from outfall serial number 005. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	**Discharge Limitations**				**Monitoring Requirements**	
	Mass (lbs/day)		Other Units (specify)		Measurement	Sample
	Monthly Avg	Daily Max	Monthly Avg	Daily Max	Frequency	Type
Flow (MGD)+	N/A	N/A	N/A	N/A	Daily	Totalizing Meter
Biochemical Oxygen Demand (BOD5)	N/A	N/A	30 mg/l	45 mg/l	Twice/month	Grab
Total Suspended Solids (TSS)	N/A	N/A	30 mg/l	45 mg/l	Twice/month	Grab
pH	N/A	N/A	Minimum 6 s.u.	Maximum 10 s.u.	Twice/month	Grab

\+ Report monthly average and daily maximum as MGD.
* See Part III, Condition No. 12.

There shall be no discharge of distinctly visible solids, scum or foam of a persistent nature, nor shall there be any formation of slime, bottom deposits or sludge banks.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at the outfall 005, following the final treatment unit.

SECTION A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS: OUTFALL 006-Wastewater holding pond (condenser drain sump, turbine building sump, floor drain and transformer area drain, and unit 1 steam generator tank drain)

During the period beginning on the effective date and lasting through date of expiration, the permittee is authorized to discharge from outfall serial number 006. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	**Discharge Limitations**				**Monitoring Requirements**	
	Mass (lbs/day)		Other Units (specify)		Measurement	Sample
	Monthly Avg	Daily Max	Monthly Avg	Daily Max	Frequency	Type
Flow (MGD)+	N/A	N/A	N/A	N/A	Daily	Totalizing Meter
Total Suspended Solids (TSS)	N/A	N/A	30 mg/l	100 mg/l	Once/week	Grab
Oil and Grease (O&G)	N/A	N/A	10 mg/l	15 mg/l	Once/week	Grab
pH	N/A	N/A	Minimum 6 s.u.	Maximum 9 s.u.	Once/week	Grab

\+ Report monthly average and daily maximum as MGD.

There shall be no discharge of distinctly visible solids, scum or foam of a persistent nature, nor shall there be any formation of slime, bottom deposits or sludge banks.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at the outfall 006, following the final treatment unit.

SECTION A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS: INTERNAL OUTFALL 007-Metal cleaning wastes

During the period beginning on the effective date and lasting through date of expiration, the permittee is authorized to discharge from outfall serial number 007. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	**Discharge Limitations**				**Monitoring Requirements**	
	Mass (lbs/day)		Other Units (specify)		Measurement	Sample
	Monthly Avg	Daily Max	Monthly Avg	Daily Max	Frequency	Type
Flow (MGD)+	N/A	N/A	N/A	N/A	Once/Batch*	Calculate
Total Suspended Solids (TSS)	N/A	N/A	30 mg/l	100 mg/l	Once/day*	Grab
Oil and Grease (O&G)	N/A	N/A	15 mg/l	20 mg/l	Once/day*	Grab
Copper, Total	N/A	N/A	1.0 mg/l	1.0 mg/l	Once/day*	Grab
Iron, Total	N/A	N/A	1.0 mg/l	1.0 mg/l	Once/day*	Grab
pH	N/A	N/A	Minimum 6 s.u.	Maximum 9 s.u.	Once/day*	Grab

\+ Report monthly average and daily maximum as MGD.
* When discharging.

There shall be no discharge of distinctly visible solids, scum or foam of a persistent nature, nor shall there be any formation of slime, bottom deposits or sludge banks.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at the outfall 007, following the final treatment unit.

SECTION A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS: OUTFALL 008-Blowdown from ultra pure water processing system

During the period beginning on the effective date and lasting through date of expiration, the permittee is authorized to discharge from outfall serial number 008. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	**Discharge Limitations**				**Monitoring Requirements**	
	Mass (lbs/day)		Other Units (specify)		Measurement	Sample
	Monthly Avg	Daily Max	Monthly Avg	Daily Max	Frequency	Type
Flow (MGD)+	N/A	N/A	N/A	N/A	Daily	Calculate*
Total Suspended Solids (TSS)	N/A	N/A	30 mg/l	100 mg/l	Once/month	Grab
Oil and Grease (O&G)	N/A	N/A	10 mg/l	15 mg/l	Once/month	Grab
pH	N/A	N/A	Minimum 6 s.u.	Maximum 9 s.u.	Once/month	Grab

\+ Report monthly average and daily maximum as MGD.
* Calculate is implied as the difference between intake water and the process effluent.

There shall be no discharge of distinctly visible solids, scum or foam of a persistent nature, nor shall there be any formation of slime, bottom deposits or sludge banks.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at the outfall 008, following the final treatment unit.

SECTION A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS: OUTFALL 009-Emergency cooling pond

During the period beginning on the effective date and lasting through date of expiration, the permittee is authorized to discharge from outfall serial number 009. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	**Discharge Limitations**				**Monitoring Requirements**	
	Mass (lbs/day)		Other Units (specify)		Measurement	Sample
	Monthly Avg	Daily Max	Monthly Avg	Daily Max	Frequency	Type
Flow (MGD)+	N/A	N/A	N/A	N/A	Daily	Estimate
Total Residual Oxidants(TRO)*	N/A	1.45	N/A	0.2 mg/l	Twice/month	Grab
Oil and Grease (O&G)	N/A	N/A	10 mg/l	15 mg/l	Twice/month	Grab
pH	N/A	N/A	Minimum 6 s.u.	Maximum 9 s.u.	Twice/month	Grab

\+ Report monthly average and daily maximum as MGD.
* See Part III, Condition No. 9.

There shall be no discharge of distinctly visible solids, scum or foam of a persistent nature, nor shall there be any formation of slime, bottom deposits or sludge banks.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at the outfall 009.

SECTION B. SCHEDULE OF COMPLIANCE

The permittee shall achieve compliance with the effluent limitations specified for discharges in accordance with the following schedule:

1. Compliance is required on the effective date of the permit.

2. The permittee shall submit progress reports for temperature in accordance with the following schedule:

	Activity	Compliance Date
1.	Submit progress report	11/1/1997
2.	Submit progress report	11/1/1998
3.	Submit final progress Report	11/1/1999

PART II — STANDARD CONDITIONS
SECTION A — GENERAL CONDITIONS

1. **Duty to Comply**
The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the federal Clean Water Act and the Arkansas Water and Air Pollution Control Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application. Any values reported in the required Discharge Monitoring Report which are in excess of an effluent limitation specified in Part 1.A. shall constitute evidence of violation of such effluent limitation and of this permit.

2. **Penalties for Violations of Permit Conditions**
The Arkansas Water and Air Pollution Control Act provides that any person who violates any provisions of a permit issued under the Act shall be guilty of a misdemeanor and upon conviction thereof shall be subject to imprisonment for not more than one (1) year, or a fine of not more than ten thousand dollars ($10,000) or by both such fine and imprisonment for each day of such violation. Any person who violates any provision of a permit issued under the Act may also be subject to civil penalty in such amount as the court shall find appropriate, not to exceed five thousand dollars ($5,000) for each day of such violation. The fact that any such violation may constitute a misdemeanor shall not be a bar to the maintenance of such civil action.

3. **Permit Action**
This permit may be modified, revoked and reissued, or terminated for cause including, but not limited to, the following:
a. Violation of any terms or conditions of this permit; or
b. Obtaining this permit by misrepresentation or failure to disclose fully all relevant facts; or
c. A change in any conditions that requires either a temporary or permanent reduction or elimination of the authorized discharge; or
d. A determination that the permitted activity endangers human health or the environment and can only be regulated to acceptable levels by permit modification or termination.
e. Failure of the permittee to comply with the provisions of ADPCE Regulation No. 9 (Permit fees) as required by condition II A. 10 herein.
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.

4. **Toxic Pollutants**
Notwithstanding Part II.A.3., if any toxic effluent standard or prohibition (including any schedule of compliance specified in such effluent standard or prohibition) is promulgated under Regulation No. 2, as amended (regulation establishing water quality standards for surface waters of the State of Arkansas) or Section 307(a) of the Clean Water Act for a toxic pollutant which is present in the discharge and that standard or prohibition is more stringent than any limitation on the pollutant in this permit, this permit shall be modified or revoked and reissued to conform to the toxic effluent standards or prohibition and the permittee so notified.

The permittee shall comply with effluent standards or prohibitions established under Regulation No. 2 (Arkansas Water Quality Standards), as amended, or Section 307(a) of the Clean Water Act for toxic pollutants within the time provided in the regulations that establish those standards or prohibitions, even if the permit has not yet been modified to incorporate the requirement.

5. **Civil and Criminal Liability**
Except as provided in permit conditions on "Bypassing" (Part II.B.4.a.), and "Upsets" (Part II.B.5.b.), nothing in this permit shall be construed to relieve the permittee from civil penalties for noncompliance. Any false or materially misleading representation or concealment of information required to be reported by the provisions of this permit or applicable state and federal statutes or regulations which defeats the regulatory purposes of the permit may subject the permittee to criminal enforcement pursuant to the Arkansas Water and Air Pollution Control Act (Act 472 of 1949, as amended).

6. **Oil and Hazardous Substance Liability**
Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties to which the permittee is or may be subject under Section 311 of the Clean Water Act.

7. **State Laws**
Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable State law or regulation under authority preserved by Section 510 of the Clean Water Act.

8. **Property Rights**
The issuance of this permit does not convey any property rights of any sort, or any exclusive privileges, nor does it authorize any injury to private property or any invasion of personal rights, nor any infringement of Federal, State or local laws or regulations.

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

10. **Permit Fees**
The permittee shall comply with all applicable permit fee requirements for wastewater discharge permits as described in ADPCE Regulation No. 9 (Regulation for the Fee System for Environmental Permits). Failure to promptly remit all required fees shall be grounds for the Director to initiate action to terminate this permit under the provisions of 40 CFR 122.64 and 124.5(d), as adopted in ADPCE Regulation No. 6, and the provisions of ADPCE Regulation No. 8.

SECTION B — OPERATION AND MAINTENANCE OF POLLUTION CONTROLS

1. **Proper Operation and Maintenance**
a. The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance also includes adequate laboratory controls and appropriate quality assurance procedures. This provision requires the operation of backup or auxiliary facilities or similar systems which are installed by a permittee only when the operation is necessary to achieve compliance with the conditions of the permit.
b. The permittee shall provide an adequate operating staff which is duly qualified to carry out operation, maintenance and testing functions required to insure compliance with the conditions of this permit.

2. **Need to Halt or Reduce Not a Defense**
It shall not be a defense for a 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. Upon reduction, loss, or failure of the treatment facility, the permittee shall, to the extent necessary to maintain compliance with its permit, control production or discharges or both until the facility is restored or alternative method of treatment is provided. This requirement applies, for example when the primary source of power for the treatment facility is reduced, is lost, or alternate power supply fails.

3. **Duty to Mitigate**
The permittee shall take all reasonable steps to minimize or prevent any discharge in violation of this permit which has reasonable likelihood of adversely affecting human health or the environment.

4. **Bypass of Treatment Facilities**
a. Bypass not exceeding limitation. The permittee may allow any bypass to occur which does not cause effluent limitations to be exceeded, but only if it also is for essential maintenance to assure efficient operation. These bypasses are not subject to the provision of Part II.B.4.b and 4.c.
b. Notice
(1) Anticipated bypass. If the permittee knows in advance of the need for a bypass, it shall submit prior notice, if possible, at least ten days before the date of the bypass.
(2) Unanticipated bypass. The permittee shall submit notice of an unanticipated bypass as required in Part II.D.6(24-hour notice).
c. Prohibition of bypass.
(1) Bypass is prohibited and the Director may take enforcement action against a permittee for bypass, unless:
(a) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;
(b) There were 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 the permittee could have installed adequate backup equipment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance, and
(c) The permittee submitted notices as required by Part II.B.4.b.
(2) The Director may approve an anticipated bypass, after considering its adverse effects, if the director determines that it will meet the three conditions listed above in Part II.B.4.c.(1).

5. **Upset Conditions**
a. Effect of an upset. An upset constitutes an affirmative defense to an action brought for noncompliance with such technology based permit effluent limitations if the requirements of Part II.B.5.b. of this section are met. No determination made during administrative review of claims that noncompliance was caused by upset, and before an action for noncompliance, is final administrative action subject to judicial review.

b. Conditions necessary for a demonstration of upset. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed, contemporaneous operating logs, or other relevant evidence that:
   (1) An upset occurred and that the permittee can identify the cause(s) of the upset;
   (2) The permitted facility was at the time being properly operated;
   (3) The permittee submitted notice of the upset as required by Part II.D.6.; and
   (4) The permittee complied with any remedial measures required by Part II.B.3.

c. Burden of proof. In any enforcement proceeding the permittee seeking to establish the occurrence of an upset has the burden of proof.

6. **Removed Substances**
Solids, sludges, filter backwash, or other pollutants removed in the course of treatment or control of wastewaters shall be disposed of in a manner such as to prevent any pollutant from such materials from entering the waters of the state. Written approval for such disposal must be obtained from the ADPCE.

7. **Power Failure**
The permittee is responsible for maintaining adequate safeguards to prevent the discharge of untreated or inadequately treated wastes during electrical power failure either by means of alternate power sources, standby generators, or retention of inadequately treated effluent.

SECTION C — MONITORING AND RECORDS

1. **Representative Sampling**
Samples and measurements taken as required herein shall be representative of the volume and nature of the monitored discharge during the entire monitoring period. All samples shall be taken at the monitoring points specified in this permit and, unless otherwise specified, before the effluent joins or is diluted by any other wastestream, body of water, or substance. Monitoring points shall not be changed without notification to and the approval of the Director. Intermittent discharges shall be monitored.

2. **Flow Measurements**
Appropriate flow measurement devices and methods consistent with accepted scientific practices shall be selected and used to insure the accuracy and reliability of measurements of the volume of monitored discharges. The devices shall be installed, calibrated and maintained to insure the accuracy of the measurements are consistent with the accepted capability of that type of device. Devices selected shall be capable of measuring flows with a maximum deviation of less than $\pm$ 10% from true discharge rates throughout the range of expected discharge volumes and shall be installed at the monitoring point of the discharge.

3. **Monitoring Procedures**
Monitoring must be conducted according to test procedures approved under 40 CFR Part 136, unless other test procedures have been specified in this permit. The permittee shall calibrate and perform maintenance procedures on all monitoring and analytical instrumentation at intervals frequent enough to insure accuracy of measurements and shall insure that both calibration and maintenance activities will be conducted. An adequate analytical quality control program, including the analysis of sufficient standards, spikes, and duplicate samples to insure the accuracy of all required analytical results shall be maintained by the permittee or designated commercial laboratory. At a minimum, spikes and duplicate samples are to be analyzed on 10% of the samples.

4. **Penalties for Tampering**
The Arkansas Water and Air Pollution Control Act provides that any person who falsifies, tampers with, or knowingly renders inaccurate, any monitoring device or method required to be maintained under the Act shall be guilty of a misdemeanor and upon conviction thereof shall be subject to imprisonment for not more than one (1) year or a fine of not more than ten thousand dollars ($10,000) or by both such fine and imprisonment.

5. **Reporting of Monitoring Results**
Monitoring results must be reported on a Discharge Monitoring Report (DMR) form (EPA No. 3320-1). Permittees are required to use preprinted DMR forms provided by ADPCE, unless specific written authorization to use other reporting forms is obtained from ADPCE. Monitoring results obtained during the previous calendar month shall be summarized and reported on a DMR form postmarked no later than the 25th day of the month following the completed reporting period to begin on the effective date of the permit. Duplicate copies of DMR's signed and certified as required by Part II.d.11 and all other reports required by Part II.D. (Reporting Requirements), shall be submitted to the Director at the following address:

Director
Arkansas Department of Pollution
Control and Ecology
8001 National Drive
P.O. Box 8913
Little Rock, AR 72219-8913

If permittee uses outside laboratory facilities for sampling and/or analysis, the name and address of the contract laboratory shall be included on the DMR.

6. **Additional Monitoring by the Permittee**
If the permittee monitors any pollutant more frequently than required by this permit, using test procedures approved under 40 CFR 136 or as specified in this permit, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR. Such increased frequency shall also be indicated on the DMR.

7. **Retention of Records**
The permittee shall retain records of all monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit, for a period of at least 3 years from the date of the sample, measurement, report or application. This period may be extended by request of the Director at any time.

8. **Record Contents**
Records and monitoring information shall include:
   a. The date, exact place, time and methods of sampling or measurements, and preservatives used, if any;
   b. The individual(s) who performed the sampling or measurements;
   c. The date(s) analyses were formed;
   d. The individual(s) who performed the analyses;
   e. The analytical techniques or methods used; and
   f. The measurements and results of such analyses.

9. **Inspection and Entry**
The permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:
   a. 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;
   b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;
   c. Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit, and
   d. Sample, inspect or monitor at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the Clean Water Act, any substances or parameters at any location.

SECTION D — REPORTING REQUIREMENTS

1. **Planned Changes**
The permittee shall give notice and provide plans and specification to the Director for review and approval prior to any planned physical alterations or additions to the permitted facility. Notice is required only when:

For Industrial Dischargers
   a. The alteration or addition to a permitted facility may meet one of the criteria for determining whether a facility is a new source in 40 CFR Part 122.29(b).
   b. The alteration or addition could significantly change the nature or increase the quantity of pollutants discharged. This notification applies to pollutants which are subject neither to effluent limitations in the permit, nor to notification requirements under 40 CFR Part 122.42(a)(1).

For POTW Dischargers:
   c. Any change in the facility discharge (including the introduction of any new source or significant discharge or significant changes in the quantity or quality of existing discharges of pollutants) must be reported to the permitting authority. In no case are any new connections, increased flows, or significant changes in influent quality permitted that will cause violation of the effluent limitations specified herein.

2. **Anticipated Noncompliance**
The permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

3. **Transfers**
The permit is nontransferable to any person except after notice to the Director. The Director may require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the Act.

4. **Monitoring Reports**
Monitoring results shall be reported at the intervals and in the form specified in Part II.C.5. (Reporting). Dischacge Monitoring Reports must be submitted even when no discharge occurs during the reporting period.

5. **Compliance Schedule**
Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than 14 days following each schedule date. Any reports of noncompliance shall include the cause of noncompliance, any remedial actions taken, and the probability of meeting the next scheduled requirement.

6. **Twenty-four Hour Report**
   a. The permittee shall report any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within 5 days of the time the permittee becomes aware of the circumstances. The written submission shall contain the following information:
      (1) a description of the noncompliance and its cause;
      (2) 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
      (3) steps taken or planned to reduce, eliminate and prevent reoccurrence of the noncompliance.
   b. The following shall be included as information which must be reported within 24 hours:
      (1) Any unanticipated bypass which exceeds any effluent limitation in the permit;
      (2) Any upset which exceeds any effluent limitation in the permit; and
      (3) Violation of a maximum daily discharge limitation for any of the pollutants listed by the Director in Part III of the permit to be reported within 24 hours.
   c. The Director may waive the written report on a case-by-case basis if the oral report has been received within 24 hours.

7. **Other Noncompliance**
   The permittee shall report all instances of noncompliance not reported under Part II.D.4, 5, and 6, at the time monitoring reports are submitted. The reports shall contain the information listed at Part II.D.6.

8. **Changes in Discharge of Toxic Substances for Industrial Dischargers**
   The permittee shall notify the Director as soon as he/she knows or has reason to believe:
   a. That any activity has occurred or will occur which would result in the discharge, in a routine or frequent basis, of any toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the "notification levels" described in 40 CFR Part 122.42(a)(2)[48 FR 14153, April 1983, as amended at 49 FR 38046, September 26, 1984].
   b. That any activity has occurred or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the "notification levels" described in 40 CFR Part 122.42(a)(2)[48 FR 14153, April 1, 1983, as amended at 49 FR 38046, September 26, 1984].

9. **Duty to Provide Information**
   The permittee shall furnish to the Director, within a reasonable time, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to detemine compliance with this permit. The permittee shall also furnish to the Director, upon request, copies of records required to be kept by this permit. Information shall be submitted in the form, manner, and time frame requested by the Director.

10. **Duty to Reapply**
    If the permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the permittee must apply for and obtain a new permit. The complete application shall be submitted at least 180 days before the expiration date of this permit. The Director may grant permission to submit an application less than 180 days in advance but no later than the permit expiration date. Continuation of expiring permits shall be governed by regulations promulgated in ADPCE Regulation No. 6.

11. **Signatory Requirements**
    All applications, reports or information submitted to the Director shall be signed and certified.
    a. All permit applications shall be signed as follows:
       (1) For a corporation: by a responsible corporate officer. For the purpose of this section, a responsible corporate officer means:
          (i) A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation; or
          (ii) the manager of one or more manufacturing, production, or operating facilities employing more than 250 persons or having gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), if authority to sign documents has been assigned or delegated to the manager in accordance with corporate procedures.
       (2) For a partnership or sole proprietorship: by a general partner or the proprietor, respectively; or
       (3) For a municipality, State, Federal, or other public agency: by either a principal executive officer or ranking elected official. For purposes of this section, a principal executive officer of a Federal agency includes:
          (i) the chief executive officer of the agency, or
          (ii) A senior executive officer having responsibility for the overall operations of a principal geographic unit of the agency.
    b. All reports required by the permit and other information requested by the Director shall be signed by a person described above or by a duly authorized representative of that person. A person is a duly authorized representative only if:
       (1) The authorization is made in writing by a person described above.
       (2) The authorization specified either an individual or a position having responsibility for the overall operation of the regulated facility or activity, such as the position of plant manager, operator of a well or a well field, superintendent, or position of equivalent responsibility. (A duly authorized representative may thus be either a named individual or any individual occupying a named position); and
       (3) The written authorization is submitted to the Director.
    c. Certification. Any person signing a document under this section shall make the following certification:

       "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."

12. **Availability of Reports**
    Except for data determined to be confidential under 40 CFR Part 2 and Regulation 6, all reports prepared in accordance with the terms of this permit shall be available for public inspection at the offices of the Department of Pollution Control and Ecology. As required by the Regulations, the name and address of any permit applicant or permittee, permit applications, permits and effluent data shall not be considered confidential.

13. **Penalties for Falsification of Reports**
    The Arkansas Air and Water Pollution Control Act provides that any person who knowingly makes any false statement, representation, or certification in any application, record, report, plan or other document filed or required to be maintained under this permit shall be subject to civil penalties specified in Part II.A.2. and/or criminal penalties under the authority of the Arkansas Water and Air Pollution Control Act (Act 472 of 1949, as amended).

PART III
OTHER CONDITIONS

1. The operator of this wastewater treatment facility shall be licensed by the State of Arkansas in accordance with Act 1103 of 1991, Act 556 of 1993, Act 211 of 1971, and Regulation No. 3, as amended.

2. Discharge flow for this outfall to be calculated based on pump capacity and run times plus the sum of all other contributing flows (Outfall 002, 004,005, and 007).

3. **Chronic Biomonitoring Requirements**

   a. Scope

   The permittee shall test Outfall **001** for toxicity in accordance with the provisions in this section. Such testing will determine if an effluent sample dilution affects the survival and/or reproduction or growth of the appropriate test organism.

   The first toxicity test must be initiated within 60 days from the effective date of the permit and the results of the test submitted with the first Discharge Monitoring Report (DMR) following completion of the toxicity test. However, if lethality is demonstrated for either test organism in any toxicity test required by this permit, the test results must be submitted to the Department within 15 days of receipt of results.

   The toxicity tests specified herein shall be conducted once per quarter.

   b. Definitions

   <u>Toxicity</u> is herein defined as a statistically significant difference at the 95% confidence level between the survival, reproduction or growth of the appropriate test organism in a specified effluent dilution and the control (0% effluent).

   <u>Lethality</u>, a component of toxicity, is herein defined as a statistically significant difference at the 95% confidence level between the survival of the appropriate test organism in a specified effluent dilution and the

control (0% effluent).

Significant nonlethal effect, a component of toxicity, is herein defined as a statistically significant difference at the 95% confidence level between the reproduction or growth of the appropriate test organism in a specified effluent dilution and the control (0% effluent).

Toxicity Reduction Evaluation (TRE) is an evaluation intended to determine those actions necessary to achieve compliance with water quality-based effluent limitations by reducing an effluent's toxicity or chemical concentration(s) to acceptable levels. A TRE is defined as a step-wise process which combines toxicity testing and analyses of the physical and chemical characteristics of a toxic effluent to identify the constituents causing effluent toxicity and/or determine the treatment methods which will reduce the effluent toxicity.

c. Test Methods

All test organisms, procedures, and quality assurance requirements used shall be in accordance with the latest revision of "Short-Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Freshwater Organisms", EPA/600/4-89/001, or the most recent update thereof, unless specified otherwise in the permit. The following tests shall be used:

i. Chronic static renewal survival and reproduction test using *Ceriodaphnia dubia* (Method 1002.0). This test should be terminated when 60% of the surviving females in the control produce three broods.

ii. Chronic static renewal 7-day larval survival and growth test using fathead minnow (*Pimephales promelas*) (Method 1000.0). A minimum of five (5) replicates with eight (8) organisms per replicate must be used for this test.

d. Test Acceptance

i. The toxicity test control (0% effluent) must have a survival equal to or greater than 80%. Should the control survival be less than 80%, the toxicity test, including control and all effluent dilutions, shall be repeated.

ii. The mean number of *Ceriodaphnia dubia* neonates produced per surviving female in the control (0% effluent) must be 15 or more. Should the control neonate production be less than 15, the toxicity test, including control and all effluent dilutions, shall be repeated.

iii. The average weight of surviving fathead minnow larvae at the end of the 7 days in the control (0% effluent) must be 0.25 mg or greater. Should the average larval weight be less than 0.25 mg, the toxicity test, including control and all effluent dilutions, shall be repeated.

iv. The percent coefficient of variation between replicates shall be 40% or less in the control (0% effluent) for:

(1) the young of surviving females in the *Ceriodaphnia dubia* reproduction test;
(2) fathead minnow growth test; and
(3) fathead minnow survival test.

v. The percent coefficient of variation between replicates shall be 40% or less for the low flow dilution (critical dilution) for ADPC&E to agree with a finding of no toxicity for these dilutions.

vi. If the permittee has conducted toxicity testing prior to the effective date of the permit in accordance with the provisions of this section, the test results may be submitted to ADPCE for approval. If approved, the test(s) will constitute partial fulfillment of the toxicity testing requirements of the permit.

e. Statistical Interpretation

i. For the *Ceriodaphnia dubia* survival test, the statistical analyses used to determine if there is a significant difference between the control and the low flow (Critical) dilution shall be Fisher's Exact Test as described in the "Short Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Freshwater Organisms", EPA/600/4-89/001, or the most recent update thereof.

ii. For the *Ceriodaphnia dubia* reproduction test and the fathead minnow larval survival and growth test, the statistical analyses used to determine if there is a significant difference between the control and the low flow (critical dilution) effluent concentration shall be in accordance with the methods for determining the No Observed Effect Concentration (NOEC) as described in the "Short-Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Freshwater Organisms", EPA/600/4-89/001, or the most recent update thereof.

f. Dilution Series

Five dilutions in addition to a control (0% effluent) composed of the same water as the dilution water, shall be used in the toxicity tests. These additional effluent dilutions shall be **32%, 42%, 56%, 75%, and 100%.** The low-flow effluent concentration (critical dilution) is defined as **100%** effluent.

g. Dilution Water

Dilution water used in the toxicity tests will be receiving water from Lake Dardanelle collected as close to the point of discharge as possible but unaffected by the discharge. If there is no receiving water due to zero flow conditions, the permittee may substitute synthetic dilution water.

If the receiving water is unsatisfactory as a result of preexisting instream toxicity (fails to fulfill the criteria of item 3.d. above, or for other reasons substantiated by the permittee) synthetic dilution water may be substituted for the receiving water, provided the following stipulations are met:

i. a synthetic dilution water control is run;

ii. the synthetic dilution water fulfills the requirements of item 3.d;

iii. A receiving water control is run concurrently with the test (provided sufficient receiving water is available), until receiving water toxicity is adequately documented to the Department.

iv. the permittee submits all test results indicating receiving water toxicity with the report and information required by item 3.m and the Discharge Monitoring Report (DMR); and

v. the synthetic dilution water shall have a pH, hardness and alkalinity similar to that of the receiving water and shall be prepared in accordance with the procedures in EPA/600/4-89/001 using ecoregion water characteristics as follows:

For discharges located in the Gulf Coastal, Arkansas River Valley, Boston Mountains, or Ouachita Mountains Ecoregions, and discharges to the Ouachita River, use <u>SOFT</u> water:

For discharges located in the Delta or Ozark Highlands Ecoregions, and discharges to the White, Arkansas, Mississippi, and St. Francis Rivers, use <u>MODERATELY HARD</u> water:

For discharges to the Red River, use <u>HARD</u> water.

Synthetic dilution water may be used in all subsequent tests for both test species provided all of the above stipulations are met.

h. Samples and Composites

A minimum of three flow-weighted 24-hour composite samples representative of the dry weather flows during normal operation will be collected from Outfall 001. A 24-hour composite sample consists of a minimum of twelve (12) effluent portions collected at equal time intervals and combined proportional to flow or a sample continuously collected proportional to flow over a 24-hour operating day.

The 24-hour composite samples must be collected such that the samples include any periodic episode of chlorination, use of a biocide or other potentially toxic substance discharged on an intermittent basis.

i. When collecting composite samples for toxicity testing, the permittee shall also analyze effluent for all parameters as specified in Part 1, Section A of this permit. These analyses may be utilized as those required in Part 1, Section A for the monitoring period encompassing the toxicity test or may be in addition to the requirements of Part 1, Section A, at the permittee's discretion. The results of these analyses shall be included in the reports required in item 3.m below.

The 24-hour composite samples must be collected so that the maximum holding time for any effluent sample shall not exceed 72 hours. The toxicity test must be initiated within 36 hours after the collection of the last portion of the first 24-hour composite sample. Samples shall be chilled to 4 degrees Centigrade during collection, shipping and/or storage.

If the flow from the outfall(s) being tested ceases during the collection of effluent samples, the requirements for the minimum number of effluent samples, the minimum number of effluent portions and the sample holding time are waived during that sampling period. However, the permittee must collect an effluent composite sample volume that is sufficient to complete the required toxicity tests with daily renewal of effluent.

j. Low Flow Lethality Testing - Special Conditions

The requirements of this subsection (item 3.j) apply only when a toxicity test at the **100%** effluent concentration demonstrates lethality.

i. The permittee shall conduct a total of two additional tests (retests) for any species that demonstrates significant lethal effects at the **100%** effluent concentration. The retests shall be conducted monthly during the next two consecutive months. The permittee shall not substitute a retest in lieu of routine toxicity testing, unless the specified testing frequency for the species demonstrating significant lethal effects is monthly. All retest data shall be submitted within 15 days of each test completion.

ii. If the results of the increased testing indicate lethality in the effluent at low flow dilution, the permittee shall submit a plan for a Toxicity Reduction Evaluation (TRE) and shall continue toxicity testing at a frequency of once per month for the species showing lethality, using the sample protocols as specified above until notified otherwise by the Department. The TRE plan, including a proposed implementation schedule, shall be submitted to the Department within 60 days of receipt of the results of the verification testing showing a lethal effluent. The plan will be reviewed by the Department. If deemed acceptable, the permittee shall be notified and the TRE plan shall become a requirement of this permit. Incomplete or unsatisfactory TRE plans and/or schedules will be returned to the permittee for correction of deficiencies. Failure to correct identified deficiencies within 30 days shall be considered a violation of this permit.

iii. The permittee shall conduct the TRE in accordance with the approved schedule and, upon completion, the permittee shall prepare a report which contains, at a minimum:

(1) the source of the toxicity (e.g. constituents; class of toxicants, suspected industrial contributors, etc.);

(2) results of any treatability studies conducted;

(3) discussion of alternative treatment or management techniques to reduce or eliminate toxicity;

(4) selection of the appropriate course of action to be followed by the permittee;

(5) an implementation schedule for making any required changes to reduce/eliminate toxicity.

iv. Upon completion of the TRE, the permittee shall select an appropriate course of action to reduce or eliminate the toxicity, and shall submit an application for modification of this permit, if applicable, including a proposed schedule for accomplishment. Additionally, if recommended solutions include construction or modification of the treatment system, an application for a construction permit shall also be submitted. The above applications shall be submitted within 90 days of completion of the TRE.

v. If none of the retests demonstrate significant lethality, the permittee shall return to the testing frequency specified in Item 3.a.

k. Low Flow Nonlethal Effects Testing - Special Conditions

The requirements of this subsection (item 3.k) apply only when a toxicity test demonstrates a significant nonlethal effect at the **100%** effluent concentration, **and** the test does not demonstrate a significant lethal effect as described in item 3.j. above.

i. Quarterly or Semi-Annual Testing: If the frequency of testing specified in this permit is quarterly or semi-annual, the permittee shall conduct a total of two (2) additional tests (retests) **for the species that demonstrated the significant nonlethal effects.** The retests shall be conducted monthly during the next two consecutive months. The permittee shall not substitute a retest in lieu of routine toxicity testing. If one of the retests shows significant non-lethal effects at the **100%** effluent concentration, the permittee may suspend the retesting for this reporting period and shall notify ADPCE in writing. All retest results shall be submitted to ADPCE within fifteen (15) days of test completion. After submitting the results which demonstrate significant non-lethal effects in one of the retests, and at the discretion of ADPCE, the permittee may be required to biomonitor for both species at an increased frequency of once per month for twelve (12) consecutive months; however, as a minimum, the permittee shall be required to biomonitor at least once per six (6) months for the remainder of the permit duration. The duration and frequency of biomonitoring will be stated in writing to the permittee.

If none of the retests demonstrate significant toxicity (lethal and nonlethal effects), the permittee shall return to the original testing frequency until fulfillment of the first year testing requirements. After the completion of the first year requirements, the permittee shall continue testing at a frequency of once per six (6) months.

ii. Monthly Testing: If the frequency of testing specified in item 3.a. is monthly, the permittee will continue testing monthly until the completion of the first year requirement and then test at a frequency of once per six (6) months for the duration of the permit.

l. No Toxicity Certification

If the toxicity tests for specific test organism(s) do not indicate toxicity at the **100%** effluent concentration during the first year or four consecutive test (whichever occurs later), the permittee shall certify this information in writing to ADPCE, and the biomonitoring requirements for that organism(s) may be reduced upon written authorization by the Department.

m. Reporting

i. The permittee shall prepare a full report of the results according to the Report Preparation Section of "Short-Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Freshwater Organisms". The full report must be submitted with the first DMR containing these biomonitoring results. Subsequent reports accompanying DMRs need include only sections 9.4 (Test Methods) and 9.7 (Results) of the full report prepared for the appropriate toxicity test, unless the full report is specifically requested by ADPCE. However, the full report shall be retained pursuant to the provisions of Part II.C.7 of this permit.

ii. The permittee shall submit the toxicity testing information contained in the summary sheet provided by ADPCE along with the DMR submitted for the end of the reporting period following each toxicity test.

n. Permit Reopener Conditions

This permit may be reopened to require effluent limits, additional testing, and/or other appropriate actions to address toxicity. Accelerated or intensified toxicity testing and/or a TRE may be required in accordance with Section 308 of the Clean Water Act, and the Arkansas Water and Air Pollution Control Act (Act 472 of 1949, as amended).

4. If any individual analytical test results is less than the minimum quantification level (MQL) listed below, a value of zero (0) may be used for that individual result for the Discharge Monitoring report (DMR) calculations and reporting requirements.

Pollutant	EPA Method	MQL (µg/l)
Zinc,Total	200.7	20

The permittee may develop a matrix specific method detection limit (MDL) in accordance with Appendix B of 40 CFR Part 136. For any pollutant for which the permittee determines a site specific MDL, the permittee shall send to ADPC&E, NPDES Permits Branch, a report containing QA/QC documentation, analytical results, and calculations necessary to demonstrate that a site specific MDL was correctly calculated. A site specific minimum quantification level (MQL) shall be determined in accordance with the following calculation:

$$MQL = 3.3 \times MDL$$

Upon written approval by the NPDES Permits Branch, the site specific MQL may be utilized by the permittee for all future Discharge Monitoring Report (DMR) calculations and reporting requirements.

5. If the sampling results at outfall 001 for oil and grease (O&G) and/or pH are below permit limitations during the first six months, the permittee shall certify this information in writing to ADPCE, so monitoring and reporting requirements for O&G and/or pH can be reduced upon written authorization by the Department without a major modification.

6. There shall be no discharge of **polychlorinated biphenyls** transformer fluid.

7. Daily average temperature is defined as the average of the

temperature measurement taken at equal time intervals not greater than two hours over the course of an operating day. The daily average temperature reported in the discharge monitoring reports (DMRs) for the month shall be the highest daily average temperature computed during the month.

8. The term "Free Available Oxidant" shall mean the value obtained using the amperometric titration method for free available chlorine described in the latest EPA approval edition of "Standard Methods for the Examination of Water and Wastewater" for total residual chlorine described in 40 CFR Part 136 for free available chlorine.

   Neither free available oxidant nor total residual oxidant may be discharged from any unit for more than **two hours** per day in any one day and not more than **one unit** in any plant may discharge free available or total residual oxidant at any one time unless the discharger demonstrates to the permitting authority that the units in a particular location cannot operate at or below the limits specified in this permit.

9. The term "Total residual oxidant" means the value obtained using the amperometric method for total residual chlorine as described in 40 CFR Part 136.

   Total residual oxidants may not be discharged from any single generating unit for more than **two hours** per day unless the permittee demonstrates to the permitting authority that discharge for more than two hours is required for macroinvertibrate control.

10. The term "low volume waste sources" means, taken collectively as if from one source, wastewater from all sources except those for which specific limitations are otherwise established. Low volume wastes sources include, but are not limited to : wastewaters from wet scrubber air pollution control systems, ion exchange water treatment system, water treatment evaporator blowdown, laboratory and sampling wastes, boiler blowdown, floor drains, cooling tower basin cleaning wastes, and recirculating house service water systems. Sanitary and air conditioning wastes are not included.

11. There shall be no discharge of cooling tower maintenance chemicals which contain the 129 priority pollutants (Appendix A of 40 CFR Part 423.)

12. Periodic discharge of maintenance chemicals (HCL, H2O2,

C6H8O7, NaCL, and NaOH)) from cleaning the ultra pure water processing system is authorized through outfall 005, provided the maintenance chemicals are first neutralized (pH 6-9) and then discharge at a rate that will not overload the hydraulic capacity or create a shock load on the sewage treatment plant.

13. Sampling of only one of the eight tanks that make up this outfall is necessary to meet the requirements of this outfall.

14. **Permit Reopener Condition:**

Stations 3, 5, and 10 shall be monitored for temperature twice/month in June, July, August, and September at a depth of three(3) feet for a period of three years . Stations 3, 5, and 10 refer to figure 1 of the letter dated April 24, 1997 which was submitted by ANO. This information must be submitted to ADPCE in accordance with the schedule of compliance in tabular form (See below). This permit shall be modified, or alternatively, revoked and reissued, to comply with any applicable provision of these requirements. If monitoring and reporting requirements indicate that different effluent limits and/or water quality limits for temperature are appropriate, the permit will be reopened and effluent limits revised.

Month	Date	Station		
		3	5	10
June				
June				
July				
July				
August				
August				
September				
September				

15. **Storm Water Pollution Prevention Plans:**

A storm water pollution prevention plan shall be developed for each facility covered by this permit. Storm water prevention plans shall be prepared in accordance with good engineering practices. The plan shall identify potential sources of pollution which may reasonably be expected to affect the quality of storm water discharges associated with industrial activity from the facility. In addition, the plan shall describe and ensure the implementation of practices which are to be used to reduce pollutants in storm water discharges associated with industrial activity at the facility and to assure compliance with the terms and conditions of this permit. Facilities must implement the provisions of the pollution prevention plan required under this part as a condition of this permit.

a. <u>Deadline for Pollution Prevention Plan Preparation and Compliance</u>.

  i. The Pollution Prevention Plan for storm water discharge associated with industrial activity:

    (1) shall be prepared on or before 60 days after issuance (and updated as appropriate);

    (2) shall provide for implementation and compliance with the terms of the plan on or before 180 days after issuance;

  ii. Upon a showing of good cause, the Director may establish a later date in writing for preparing and coming into compliance with a Pollution Prevention Plan for a storm water discharge associated with industrial activity.

b. <u>Signature and Plan Review</u>

  i. The plan shall be signed in accordance with Part III.15.d.vii (signatory requirements), and shall be retained on site at the facility which generates the storm water discharge in accordance with Part III.15.d.vi (retention of records) of this permit.

  ii. The permittee shall make plans available upon request to the Director, or authorized representative, or in the case of a storm water discharge associated with industrial activity which discharges through a municipal separate storm sewer system to the operator of the municipal system.

iii. The Director, or authorized representative, may notify the permittee at any time that the plan does not meet one or more of the minimum requirements of this Part. Within 30 days of such notification, or as otherwise provided by the Director, the permittee shall make changes to the plan and submit to the Director a written certification that the requested changes have been made.

c. Keeping Plans Current. The permittee shall amend the plan whenever there is a change in design, construction, operation, or maintenance, which has a significant affect on the potential for the discharge of pollutants to the waters of the State or if the storm water pollution prevention plan proves to be ineffective in eliminating or significantly minimizing pollutants from sources identified under Part III.15.d.ii (description of potential pollutant sources), or in otherwise achieving the general objectives of controlling pollutants in storm water discharges associated with industrial activity. Amendments to the plan may be reviewed by ADPCE in the same manner as Part III.15.b (signature and plan review) above.

d. The plan shall include, at a minimum, the following items:

i. Pollution Prevention Team. Each plan shall identify specific individual or individuals within the facility organization as members of a storm water Pollution Prevention Team that are responsible for developing the plan and assisting the facility or plant manager in its implementation, maintenance and revision. The plan shall clearly identify the responsibilities of each team member. The activities and responsibilities of the team shall address all aspects of the facility's storm water pollution prevention plan.

ii. Description of potential pollutant sources. Each plan shall provide a description of potential sources which may be reasonably expected to add significant amounts of pollutants to storm water discharges or which may result in the discharge of pollutants during dry weather from separate storm sewers draining the facility. Each plan shall identify all activities and significant materials which may potentially be significant pollutant sources. Each plan shall include, at a minimum;

(1) Drainage:

(a) A site map indicating an outline of the drainage area of each storm water outfall that are within the facility boundaries, each existing structural control measure to reduce pollutants in storm water runoff, surface water bodies, locations where significant materials are exposed to precipitation, locations where major spills or leaks identified under Part III.15.d.ii.3(spills and leaks) of this permit have occurred, and the locations of the following activities where such activities are exposed to precipitation: fueling stations, vehicle and equipment maintenance and/or cleaning areas, loading/unloading areas, locations used for the treatment, storage or disposal of wastes, liquid storage tanks, processing areas and storage areas.

(b) For each area of the facility that generates storm water discharges associated with industrial activity with a reasonable potential for containing significant amounts of pollutants, a prediction of the direction of flow, and identification of the types of pollutants which are likely to be present in storm water discharges associated with industrial activity. Factors to consider include the toxicity of chemicals; quantity of chemicals used, produced or discharged; the likelihood of contact with storm water; and the history of significant leaks or spills of toxic or hazardous pollutants. Flows with a significant potential for causing erosion shall be identified.

(2) Inventory of Exposed Materials:

An inventory of the types of materials handled at the site that potentially may be exposed to precipitation. Such inventory shall include a narrative description of significant materials that have been handled, treated, stored, or disposed in a manner to allow exposure to storm water between the time three years prior to the effective date of this permit and the present; method and location of on-site storage and disposal; materials management practices employed to minimize contact of these materials with storm water runoff between the time of three years prior to the effective date of this permit and the present; the location and a description of existing structural and nonstructural control measures to reduce pollutants in storm water runoff; and a description of any treatment the storm water receives.

(3) Spills and Leaks:

A list of significant spills and significant leaks of toxic or hazardous pollutants that occurred at areas exposed to precipitation or that otherwise drain to a storm water conveyance at the facility after the date of three years prior to the effective date of this permit. Such list shall be updated as appropriate during the term of the permit.

(4) Sampling Data:

A summary of existing discharge sampling data describing pollutants in storm water discharges from the facility, including a summary of sampling data collected during the term of this permit.

(5) Risk Identification and Summary of Potential Pollutant Sources:

A narrative description of the potential pollutant sources at the following areas:

loading and unloading operations; outdoor storage activities; outdoor manufacturing or processing activities; significant dust or particulate generating processes; and on-site waste disposal practices. The description shall specifically list any significant potential source of pollutants at the site and for each potential source, any pollutant or pollutant parameter (e.g. biochemical oxygen demand, etc.) of concern shall be identified.

iii. Measures and Controls. Each facility covered by this permit shall develop a description of storm water management controls appropriate for the facility, and implement such controls. The appropriateness and priorities of controls in a plan shall reflect identified potential sources of pollutants at the facility. The description of storm water management controls shall address the following minimum components, including a schedule for implementation:

(1) Good Housekeeping. Good housekeeping requires maintenance of areas which may contribute pollutants to storm water discharges in a clean, orderly manner.

(2) Preventive Maintenance. A preventive maintenance program shall involve inspection and maintenance of storm water management devices (cleaning oil/water separators, catch basins, etc.) as well as inspecting and testing plant equipment and systems to uncover conditions that could cause breakdowns or failures resulting in discharges of pollutants to surface waters, and ensuring appropriate maintenance of such equipment and systems.

(3) Spill Prevention and Response Procedures. Areas where potential spills which can contribute pollutants to storm water discharges can occur, and their accompanying drainage points shall be identified clearly in the storm water pollution prevention plan. Where appropriate, specifying material handling procedures, storage requirements and use of equipment such as diversion valves in

the plan should be considered. Procedures for cleaning up spills shall be identified in the plan and made available to the appropriate personnel. The necessary equipment to implement a clean up should be available to personnel.

(4) Inspections. In addition to or as part of the comprehensive site evaluation required under Part III.15.d.iv (comprehensive site compliance evaluation) of this permit, qualified facility personnel shall be identified to inspect designated equipment and areas of the facility at appropriate intervals specified in the plan. A set of tracking or follow-up procedures shall be used to ensure that appropriate actions are taken in response to the inspections. Records of inspections shall be maintained at the facility.

(5) Employee Training. Employee training programs shall inform personnel responsible for implementing activities identified in the storm water pollution prevention plan or otherwise responsible for storm water management at all levels of responsibility of the components and goals of the storm water pollution prevention plan. Training should address topics such as spill response, good housekeeping and material management practices. A pollution prevention plan shall identify periodic dates for such training.

(6) Recordkeeping and Internal Reporting Procedures. A description of incidents such as spills, or other discharges, along with other information describing the quality and quantity of storm water discharges shall be included in the plan required under this part. Inspections and maintenance activities shall be documented and records of such activities shall be incorporated into the plan.

(7) Non-Storm Water Discharges.

(a) The plan shall include a certification that the discharge has been tested or evaluated for the presence of non-storm water discharges. The certification shall include the identification of potential significant sources of non-storm water at the site, a description of the results of any test and/or evaluation for the presence of non-storm water discharges, the evaluation criteria and testing method used, the date of any testing and/or evaluation, and the on-site drainage points that were directly observed during a test. Certifications shall be signed in accordance with Part III.15.d.vii (signatory requirements) of this permit. Such certification may not be feasible if the facility operating the storm water discharge associated with industrial activity does not have access to an outfall, manhole or other point of access to the ultimate conduit which receives the discharge. In such cases, the source identification section of the storm water pollution plan shall indicate why the certification required by this part was not feasible, along with the identification of potential significant sources of non-storm water at the site.

(b) Except for flows from fire fighting activities, sources of non-storm water listed in subparagraph (a) above (authorized non-storm water discharges) of this permit that are combined with storm water 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 non-storm water component(s) of the discharge.

(8) Sediment and Erosion Control. The plan shall identify areas which, due to topography, activities, or other factors, have a high potential for significant soil erosion, and identify structural, vegetative, and/or stabilization measures to be used to limit

erosion.

(9) Management of Runoff. The plan shall contain a narrative consideration of the appropriateness of traditional storm water management practices (practices other than those which control the source of pollutants) used to divert, infiltrate, reuse, or otherwise manage storm water runoff in a manner that reduces pollutants in storm water discharges from the site. The plan shall provide that measures determined to be reasonable and appropriate shall be implemented and maintained. The potential of various sources at the facility to contribute pollutants to storm water discharges associated with industrial activity shall be considered when determining reasonable and appropriate measures. Appropriate measures may include: vegetative swales and practices, reuse of collected storm water (such as for a process or as an irrigation source), inlet controls (such as oil/water separators), snow management activities, infiltration devices, and wet detention/retention devices.

iv. Comprehensive Site Compliance Evaluation. Qualified personnel shall conduct site compliance evaluations at appropriate intervals specified in the plan, but in no case less than once a year. Such evaluation should include:

(1) Areas contributing to a storm water 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 storm water management measures, sediment and 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.

(2) based on the results of the inspection, the description of potential pollutant sources identified in the plan in accordance with Part III.15.d.ii (description of potential pollutant sources) of this permit and pollution prevention measures identified in the plan in accordance with Part III.15.d.iii (measures and controls) of this permit shall be revised as appropriate within two (2) weeks of such inspection and shall provide for implementation of any changes to the plan made in accordance with the plan in a timely manner, but in no case more than twelve (12) weeks from the inspection.

(3) a report summarizing the scope of the inspection, personnel making the inspection, and date(s) of the inspection, major observations relating to the implementation of the storm water pollution prevention plan, and actions taken in accordance with Part III.15.d.iv.2 above shall be made and retained as part of the Storm Water Pollution Prevention Plan for at least three years. The report shall be signed in accordance with Part III.15.d.vii (signatory requirements) of this permit.

v. Consistency with other plans. Storm water management programs may reflect requirements for Spill Prevention Control and Countermeasure (SPCC) plans under section 311 of the Clean Water Act (CWA) or Best Management Practices (BMP) Programs otherwise required by an NPDES permit for the facility as long as such requirement is incorporated into the storm water pollution prevention plan.

vi. Retention of Records. The permittee shall retain the pollution prevention plan developed for at least one year after coverage under the permit terminates. The permittee shall retain records of all monitoring information, keep copies of all reports required by this permit, and records of all data used to complete the application of this permit for at least one year after coverage for this permit is terminated. This period may be explicitly extended by request of the Director at any time.

vii. <u>Signatory Requirements.</u> Storm water pollution prevention plans, reports, certifications or information submitted to the Director or the operator of a large or medium municipal separate storm sewer system, and any other reports required to be maintained by the permittee, shall be signed and certified.

(1) All applications shall be signed as follows:

(a) For a corporation: by a responsible corporate officer. For purposes of this section, a responsible corporate officer means:

(i) a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation; or

(ii) the manager or one or more manufacturing, production, or operating facilities employing more than 250 persons or having gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), if authority to sign documents has been assigned or delegated to the manager in accordance with corporate procedures.

(b) For a partnership or sole proprietorship: by a general partner or the proprietor, respectively; or

(c) For a municipality, State, Federal or other public agency: By either a principal executive or ranking elected official. For purposes of this section, a principal executive officer of a Federal agency includes:

(i) the chief executive officer of the agency; or

(ii) a senior executive officer having responsibility for the overall operations of a principal geographic unit of the agency.

(d) All reports required by the permit and other information requested by the Director shall be signed by a person described above or by a duly authorized representative of that person. A person is a duly authorized representative only if:

(i) the authorization is made n writing by a person described above and submitted to the Director;

(ii) the authorization specifies either an individual or a person having responsibility for the overall operation of the regulated facility or activity, such as the position of plant manager, operator of a well or a well field, superintendent, or position of equivalent responsibility, or position of equivalent responsibility for environmental matters for the company. (A duly authorized representative may thus be either a named individual or any individual occupying a named position); and

e. Changes to authorization. If an authorization under this subpart is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the above requirement must be submitted to the Director prior to or together with any reports, information, or applications to be signed by an authorized representative.

i. <u>Special requirements for storm water discharges associated with industrial activity from facilities subject to SARA Title III, Section 313 requirements</u>. In addition to the requirements of Parts III.15.d.i through 15.d.iv and other applicable conditions of this permit, storm water pollution prevention plans for facilities subject to reporting requirements under SARA Title III, Section 313 for chemicals which are classified as "Section 313 water priority chemicals", shall describe and ensure the implementation of practices which are necessary to provide for conformance with the following guidelines.

(1) in areas where Section 313 water priority chemicals are stored, processed, or otherwise handled, appropriate containment, drainage control and/or diversionary structures shall be provided. At a minimum, one of the following preventive systems or its equivalent shall be used:

(a) Curbing, culverting, gutters, sewers, or other forms of drainage control to prevent or minimize the potential for storm water run-on to come into contact with significant sources of pollutants; and

(b) Roofs, covers, or other forms of appropriate protection to prevent storage piles from exposure to storm water and wind.

(2) In addition to the minimum standards listed under Part III.15.e.i.1 above (special requirements for storm water discharges associated with industrial activity from facilities subject to SARA Title III, Section 313 requirements), the storm water pollution prevention plan shall include a complete discussion of measures taken to conform with the following guidelines, as applicable, and other effective storm water pollution prevention guidelines:

(a) <u>Liquid storage areas where storm water comes into contact with any equipment, tank, container, or other vessel used for Section 313 water priority chemicals</u>.

(i) no tank or container shall be used for the storage of a Section 313 water priority chemical unless its material and construction are compatible with the material being stored and conditions of storage such as pressure and temperature, etc.

(ii) liquid storage areas for Section 313 water priority chemicals shall be operated to minimize discharges of Section 313 materials. Appropriate measures to minimize discharges of Section 313 chemicals may include secondary containment provided for at least the entire contents of the largest single tank plus sufficient freeboard to allow for precipitation, a strong spill contingency and integrity testing plan, and/or other equivalent measures.

(b) <u>material storage areas for Section 313 water priority chemicals other than liquids.</u> Material storage areas for Section 313 water priority chemicals other than liquids which are subject to runoff, leaching, or wind blowing shall incorporate drainage or other control features which will minimize the discharge of Section 313 water priority chemicals by reducing storm water contact with Section 313 water priority chemicals.

(c) <u>truck and rail car loading and unloading areas for Section 313 water priority chemicals</u>. Truck and rail car loading and unloading areas for liquid Section 313 water priority chemicals shall be operated to minimize discharges of Section 313 water priority chemicals. Appropriate measures to minimize discharges of Section 313 chemicals may include: the placement and maintenance of drip pans (including the proper disposal of materials collected in the drip pans) where spillage may occur (such as hose connections, hose reels and filler nozzles) for use when making and breaking hose connections; a strong spill contingency and integrity testing plan; and/or other equivalent measures.

(d) areas where Section 313 water priority chemicals are transferred, processed, or otherwise handled. Processing equipment and materials handling equipment shall be operated so as to minimize discharges of Section 313 water priority chemicals. Materials used in piping and equipment shall be compatible with the substances handled. Drainage from process and materials handling areas shall minimize storm water contact with Section 313 water priority chemicals. Additional protection such as covers or guards to prevent exposure to wind, spraying or releases from pressure relief vents from causing a discharge of Section 313 water priority chemicals to the drainage system, and overhangs or door skirts to enclose trailer ends at truck loading/unloading docks shall be provided as appropriate. Visual inspections or leak tests shall be provided for overhead piping conveying Section 313 water priority chemicals without secondary containment.

(e) discharges from areas covered in paragraphs (a), (b), (c), or (d) (above).

(i) drainage from areas covered by paragraphs (a), (b), (c), or (d) of this part shall be restrained by valves or other positive means to prevent the discharge of a spill or other excessive leakage of Section 313 water priority chemicals. Where containment units are employed, such units may be emptied by pumps or ejectors; however, these shall be manually operated.

(ii) flapper-type drain valves shall not be used to drain containment areas. Valves used for the drainage of containment areas should, as far as is practical, be of manual, open-and-closed design.

(iii) if facility drainage is not engineered as above, the final discharge of all in-facility storm sewers shall be equipped with a diversion system that could, in the event of an uncontrolled spill of Section 313 water priority chemicals, return the spilled material to the facility.

(iv) Records shall be kept of the frequency and estimated volume (in gallons) of discharges from containment areas.

(f) <u>facility site runoff other than from areas covered by (a), (b), (c), or (d)</u>. Other areas of the facility (those not addressed in paragraphs (a), (b), (c), or (d)) from which runoff which may contain Section 313 water priority chemicals could cause a discharge shall incorporate the necessary drainage or other control features to prevent discharge of spilled or improperly disposed material and ensure the mitigation of pollutants in runoff or leachate.

(g) preventive maintenance and housekeeping. All areas of the facility shall be inspected at specific intervals for leaks or conditions that could lead to discharges of Section 313 water priority chemicals or direct contact of storm water with raw materials, intermediate materials, waste materials or products. In particular, facility piping, pumps, storage tanks and bins, pressure vessels, process and material handling equipment, and material bulk storage areas shall be examined for any conditions or failures which could cause a discharge. Inspections shall include an examination for leaks, wind blowing, corrosion, support or foundation failure, or other forms of deterioration or noncontainment. Inspection intervals shall be specified in the plan and shall be based on design and operational experience. Different areas may require different inspection intervals. Where a leak or other condition is discovered which may result in significant releases of Section 313 water priority chemicals to the drainage system, corrective action shall be immediately taken or the unit or process shut down until corrective action can be taken. When a leak or noncontainment of a Section 313 water priority chemical has occurred, contaminated soil, debris, or other material must be promptly removed and disposed in accordance with Federal, State, and local requirements and as described in the plan.

(h) facility security. Facilities shall have the necessary security systems to prevent accidental or intentional entry which could cause a discharge. Security systems described in the plan shall address fencing, lighting, vehicular traffic control, and securing of equipment and buildings.

(i) training. Facility employees and contractor personnel that work in areas where SARA Title III, Section 313 water priority chemicals are used or stored shall be trained in and informed of preventive measures at the facility. Employee training shall be conducted at intervals specified in the plan, but not less than once per year, in matters of pollution control laws and regulations, the storm water pollution prevention plans, and the particular features of the facility and its operation which are designed to minimize discharges of Section 313 water priority chemicals. The plan shall designate a person who is accountable for spill prevention at the facility and who will set up the necessary spill emergency procedures and reporting requirements so that spills and emergency releases of Section 313 water priority chemicals can be isolated and contained before a discharge of a Section 313 water priority chemical can occur. Contractor or temporary personnel shall be informed of plant operation and design features in order to prevent discharges or spills from occurring.

(ii) Engineering certification. The storm water pollution prevention plan for facilities subject to SARA Title III, Section 313 for chemicals which are classified as "Section 313 water priority chemicals" shall be reviewed by a Registered Professional Engineer and certified to by such Professional Engineer. A Registered Professional Engineer shall recertify the plan every three (3) years thereafter or as soon as practicable after significant modifications are made to the facility. By means of these certifications the engineer, having examined the facility and being familiar with the provisions of this part, shall attest that the storm water pollution prevention plan has been prepared in accordance with good engineering practices. Such certifications shall in no way relieve the owner or operator of a facility covered by the plan of their duty to prepare and fully implement such plan.

PART IV — SECTION A — DEFINITIONS

All definitions contained in Section 502 of the Clean Water Act shall apply to this permit and are incorporated herein by reference. Additional definitions of words or phrases used in this permit are as follows:

1. "Act" means the Clean Water Act, Public Law 95-217(33. U.S.C. 1251 et seq.) as amended.
2. "Administrator" means the Administrator of the U.S. Environmental Protection Agency.
3. "Applicable effluent standards and limitations" means all State and Federal effluent standards and limitations to which a discharge is subject under the Act, including, but not limited to, effluent limitations, standards of performance, toxic effluent standards and prohibitions, and pretreatment standards.
4. "Applicable water quality standards" means all water quality standards to which a discharge is subject under the federal Clean Water Act and which have been (a) approved or permitted to remain in effect by the Administrator following submission to the Administrator pursuant to Section 303(a) of the Act, or (b) promulgated by the Director pursuant to Section 303(b) or 303(c) of the Act, and standards promulgated under regulation No. 2, as amended, (regulation establishing water quality standards for surface waters of the State of Arkansas).
5. "Bypass" means the intentional diversion of waste streams from any portion of a treatment facility.
6. "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 terms of mass, the "daily discharge" is calculated as the total mass of the pollutant discharged over the sampling 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 sampling day. "Daily discharge" determination of concentration made using a composite sample shall be the concentration of the composite sample. When grab samples are used, the "daily discharge" determination of concentration shall be the arithmetic average (weighted by flow value) of all the samples collected during that sampling day.
7. "Daily Average" (also known as monthly average) discharge limitations means the highest allowable average of "daily discharge(s)" over a calendar month, calculated as the sum of all "daily discharge(s)" measured during a calendar month divided by the number of "daily discharge(s)" measured during that month. When the permit establishes daily average concentration effluent limitations or conditions, the daily average concentration means the arithmetic average (weighted by flow) of all "daily discharge(s)" of concentration determined during the calendar month where C = daily concentration, F = daily flow and n = number of daily samples; daily average discharge =
$$\frac{C1F1 + C2F2 + \ldots CnFn}{F1 + F2 + \ldots + Fn}$$
8. "Daily Maximum" discharge limitation means the highest allowable "daily discharge" during the calendar month.
9. "Department" means the Arkansas Department of Pollution Control and Ecology (ADPCE).
10. "Director" means the Administrator of the U.S. Environmental Protection Agency and/or the Director of the Arkansas Department of Pollution Control and Ecology.
11. "Grab sample" means an individual sample collected in less than 15 minutes in conjunction with an instantaneous flow measurement.
12. "Industrial User" means a nondomestic discharger, as identified in 40 CFR 403, introducing pollutants to a publicly-owned treatment works.
13. "National Pollutant Discharge Elimination System" means the national program for issuing, modifying, revoking and reissuing, terminating, monitoring and enforcing permits, and imposing and enforcing pretreatment requirements, under sections 307, 402, 318, and 405 of the Clean Water Act.
14. "POTW" means a Publicly Owned Treatment Works.
15. "Severe property damage" means substantial physical damage to property, damage to the treatment facilities which causes them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in productions.
16. "ADPCE" means the Arkansas Department of Pollution Control and Ecology.
17. "Sewage sludge" means the solids, residues, and precipitate separated from or created in sewage by the unit processes of a publicly-owned treatment works. Sewage as used in this definition means any wastes, including wastes from humans, households, commercial establishments, industries, and storm water runoff, that are discharged to or otherwise enter a publicly-owned treatment works.
18. "7-day average" discharge limitation, other than for fecal coliform bacteria, is the highest allowable arithmetic means of the values for all effluent samples collected during the calendar week. The 7-day average for fecal coliform bacteria is the geometric mean of the values of all effluent samples collected during the calendar week. The DMR should report the highest 7-day average obtained during the calendar month. For reporting purposes, the 7-day average values should be reported as occurring in the month in which the Saturday of the calendar week falls in.
19. "30-day average", other than for fecal coliform bacteria, is the arithmetic mean of the daily values for all effluent samples collected during a calendar month, calculated as the sum of all daily discharges measured during a calendar month divided by the number of daily discharges measured during that month. The 30-day average for fecal coliform bacteria is the geometric mean of the values for all effluent samples collected during a calendar month.
20. "24-hour composite sample" consists of a minimum of 12 effluent portions collected at equal time intervals over the 24-hour period and combined proportional to flow or a sample collected at frequent intervals porportional to flow over the 24-hour period.
21. "12-hour composite sample" consists of 12 effluent portions collected no closer together than one hour and composited according to flow. The daily sampling intervals shall include the highest flow periods.
22. "6-hour composite sample" consists of six effluent portions collected no closer together than one hour (with the first portion collected no earlier than 10:00 a.m.) and composited according to flow.
23. "3-hour composite sample" consists of three effluent portions collected no closer together than one hour (with the first portion collected no earlier than 10:00 a.m.) and composited according to flow.
24. "Treatment works" means any devices and systems used in the storage, treatment, recycling, and reclamation of municipal sewage and industrial wastes, of a liquid nature to implement section 201 of the Act, or necessary to recycle reuse water at the most economic cost over the estimated life of the works, including intercepting sewers, sewage collection systems, pumping, power and other equipment, and alterations thereof; elements essential to provide a reliable recycled supply such as standby treatment units and clear well facilities, and any works, including site acquisition of the land that will be an integral part of the treatment process or is used for ultimate disposal of residues resulting from such treatment.
25. "Upset" means an exceptional incident in which there is unintentional and temporary noncompliance with technology-based permit effluent limitations because of factors beyond the reasonable control of the permittee. Any upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, lack of preventive maintenance, or careless or improper operations.
26. For "fecal coliform bacteria", a sample consists of one effluent grab portion collected during a 24-hour period at peak loads.
27. "Dissolved oxygen", shall be defined as follows:
    a. When limited in the permit as a monthly minimum, shall mean the lowest acceptable monthly average value, determined by averaging all samples taken during the calendar month;
    b. When limited in the permit as an instantaneous minimum value, shall mean that no value measured during the reporting period may fall below the stated value.
28. The term "MGD" shall mean million gallons per day.
29. The term "mg/l" shall mean milligrams per liter or parts per million (ppm)
30. The term "μg/l" shall mean micrograms per liter or parts per billion (ppb)

<u>**Attachment C**</u>

U.S. Fish and Wildlife Service Correspondence:

Letter from Dr. Gary E. Tucker, FTN Associates, Ltd., to Marge Harney, U.S. Fish and Wildlife Service, dated August 4, 1997

Letter from Dr. Gary E. Tucker, FTN Associates, Ltd., to Margaret Harney, U.S. Fish and Wildlife Service, dated September 2, 1999

AUG 6 1997
FISH & WILDLIFE SER
VICKSBURG, MS

ftn Associates Ltd.
water resources / environmental consultants

August 4, 1997

Ms. Marge Harney
US Fish and Wildlife Service
2524 S Frontage Rd, Suite B
Vicksburg, MS 39180-5269

RE: Federally Listed Species for Industrial Facility, Pope County, Arkansas
FTN No. 6045-060

Dear Ms. Harney:

FTN Associates, Ltd. (FTN) is conducting reviews of potential environmental issues at an industrial client's facilities in Arkansas. The legal description for a facility in Pope County is SW¼ SW¼ of Section 27 and S½ of SE¼ of Section 28, Township 8 North, Range 21 West. Also, the facility's boundary extends barely into the NE¼ of Section 33 and NW¼ of Section 34, Township 8 North, Range 21 West.

With this letter, we are requesting from you a list of federally listed species having a potential for occurrence at the Pope County facility. From our review of pertinent literature, FTN has identified five animal species having geographic ranges that would include Pope County, at least on a historical basis. These species include: bald eagle, red-cockaded woodpecker, interior least tern, Bachman's warbler, and Florida panther. Of these five species, however, we have found no solid evidence that either live organisms or suitable habitat for any of the five animal species is expected within the confines of the facility, with the possible exception of occasional stray bald eagle individuals flying within the boundaries of the facility on rare occasions. We have identified no plant species having a potential for occurrence within the facility's boundaries. We look forward to receiving a written response from you relative to our preliminary assessment about these species.

If you have questions or need additional information, please call me or Bob West at (501) 225-7779.

Kindest regards,
FTN ASSOCIATES, LTD.

Gary E. Tucker

Gary E. Tucker, PhD
Project Scientist

N:\WP_FILES\6045-060\L-HARNEY.WP\JBW

No federally listed endangered, threatened or candidate species present

Margaret Harney

Environmental Coordinator
U.S. Fish and Wildlife Service

Log# 97-762

Aug 7, 1997
Date

3 Innwood Circle • Suite 220 • Little Rock, AR 72211
(501) 225-7779 • Fax (501) 225-6738
Web Site: www.ftn-assoc.com
E-mail: ftn@ftn-assoc.com

6045-060
Entry

ftn Associates Ltd.
water resources / environmental consultants

RECEIVED
SEP 03 1999
ARK FIELD
OFFICE

September 2, 1999

Ms. Margaret Harney
US Fish and Wildlife Service
1500 Museum Road
Suite 105
Conway, AR 73032

RE: Request for Information Regarding Federally Listed Threatened and Endangered Species, Application for Extension of Nuclear Regulatory Commission License Period, Arkansas Nuclear One Facility, near Russellville, Pope County, Arkansas
FTN No. 6045-061

Dear Ms. Harney:

The purpose of this letter is to follow up on our phone conversation of August 26, 1999 regarding Entergy's Arkansas Nuclear One (ANO) facility permitting issues. You will recall from our conversation that I said we soon would be providing a request for information regarding federally listed threatened and endangered species having a potential for occurrence within ANO's existing transmission line corridors. The enclosed map provides you with approximate corridor locations.

Following construction of the original power generating facilities and transmission lines, ANO went online in 1974 under the authorization of a license issued by Nuclear Regulatory Commission. That original license will expire in 2014, and Entergy is presently preparing an application for an extension of existing operations until 2034. Please note that the application solely addresses a continuation of existing operations and does not involve any new construction or other deviation from the *status quo*.

If you have questions or need additional information, please feel free to call me or Bob West at (501) 225-7779.

Kindest regards,
FTN ASSOCIATES, LTD.

Bob West For

Gary E. Tucker, PhD, PWS
Environmental Scientist

CC: Rick Buckley - Entergy

Enclosure

P:\WP_FILES\6045-061\L-MARGE.WPD\BMW

No federally listed endangered, threatened or candidate species present

Deborah W. Rayfield
Environmental Coordinator
U.S. Fish and Wildlife Service

Log# 99-491

10-1-99
Date

3 Innwood Circle • Suite 220 • Little Rock, AR 72211
(501) 225-7779 • Fax (501) 225-6738

2949 Point Circle • Suite 1 • Fayetteville, AR 72704
(501) 571-3334 • Fax (501) 571-3338

Web Site: www.ftn-assoc.com
E-mail: ftn@ftn-assoc.com

6045-061 ANO Relicensing

Attachment D

Arkansas Natural Heritage Commission Correspondence:

Letter from Cindy Osborne, Arkansas Natural Heritage Commission, to Dr. Gary E. Tucker, FTN Associates, Ltd., dated August 19, 1997.

Letter from Cindy Osborne, ANHC to Gary E. Tucker, FTN dated September 29, 1999 (Client Contact Report dated October 4, 1999)

Personal communication between Gary E. Tucker and Cindy Osborne, ANHC, dated October 13, 1999

ARKANSAS NATURAL HERITAGE COMMISSION
1500 TOWER BUILDING
323 CENTER STREET
LITTLE ROCK, ARKANSAS 72201

Harold K. Grimmett
Director

Mike Huckabee
Governor

Date: August 19, 1997
Subject: Elements of Special Concern
Industrial Facility, Pope Co.
FTN No. 6045-060
ANHC No.: P-CF..-97-059

Dr. Gary Tucker
FTN Associates Ltd.
3 Innwood Circle, Suite 220
Little Rock, AR 72211

Dear Dr. Tucker:

Staff members of the Arkansas Natural Heritage Commission have reviewed our files for records indicating the occurrence of rare plants and animals, outstanding natural communities or other elements of special concern within or near the industrial site in Sections 27, 28, 33, and 34 of Township 8 North, Range 21 West in Pope County, Arkansas. We find no records at the present time.

A Pope County Element List has been enclosed for your reference. Represented on this list are elements for which we have records in our database in this county. A "✓" has been placed by those elements falling on the same topographic quadrangle (Russellville West 7.5') as the project site. A legend is enclosed to help you interpret the codes on the list.

Please keep in mind that the project area may contain important natural features of which we are unaware. Staff members of the Arkansas Natural Heritage Commission have not conducted a field survey of the project site. Our review is based on data available to the program at the time of the request. It should not be regarded as a final statement on the elements or areas under consideration, nor should it be substituted for on-site surveys required for environmental assessments. Because our files are updated constantly, you may want to check with us again at a later time.

Thank you for consulting us. It has been a pleasure to work with you on this study.

Sincerely,

Cindy Osborne

Cindy Osborne
Data Manager

Enclosure: Legend
Pope County Element List, annotated
Invoice

.9 AUG 1997

ARKANSAS NATURAL HERITAGE COMMISSION
DEPARTMENT OF ARKANSAS HERITAGE
INVENTORY RESEARCH PROGRAM
ELEMENTS OF SPECIAL CONCERN
POPE COUNTY

ELEMENT NAME	FEDERAL STATUS	STATE STATUS	GLOBAL RANK	STATE RANK
** Animals				
* Invertebrates				
CAMBARUS CAUSEYI, A CRAYFISH	-	INV	G1	S1
LIRCEUS BICUSPIDATUS, AN ISOPOD	-	INV	G3Q	S3
* Vertebrates				
CORYNORHINUS RAFINESQUII, RAFINESQUE'S BIG-EARED BAT	-	INV	G3G4	S2
EGRETTA CAERULEA, LITTLE BLUE HERON	-	INV	G5	S2
HYLA AVIVOCA, BIRD-VOICED TREEFROG	-	INV	G5	S2?
MYOTIS GRISESCENS, GRAY MYOTIS	LE	INV	G2G3	S2
PERCINA NASUTA, LONGNOSE DARTER	3C	INV	G3	S2
PODILYMBUS PODICEPS, PIED-BILLED GREBE	-	INV	G5	S2?
PSEUDACRIS STRECKERI STRECKERI, STRECKER'S CHORUS FROG	-	INV	G5T4	S1?
RANA AREOLATA CIRCULOSA, NORTHERN CRAWFISH FROG	-	INV	G4T4	S1?
REGINA SEPTEMVITTATA, QUEEN SNAKE	-	INV	G5	S1?
SPEA BOMBIFRONS, PLAINS SPADEFOOT	-	INV	G5	S1
STERNA ANTILLARUM ATHALASSOS, INTERIOR LEAST TERN	LE	INV	G4T2Q	S2
** Plants				
* Vascular Plants				
CAREX CAREYANA, CAREY'S SEDGE	-	INV	G5	S2
CAREX COMMUNIS, FIBROUS-ROOT SEDGE	-	INV	G5	S2S3
CASTANEA PUMILA VAR. OZARKENSIS, OZARK CHINQUAPIN	-	INV	G5T3	S3S4
CAULOPHYLLUM THALICTROIDES, BLUE COHOSH	-	INV	G5	S2
DELPHINIUM NEWTONIANUM, MOORE'S LARKSPUR	3C	INV	G3	S3
DRABA APRICA, OPEN-GROUND WHITLOW-GRASS	3C	ST	G3	S2
ERIOCAULON KORNICKIANUM, SMALL-HEADED PIPEWORT	-	SE	G2G3	S2
EUPHORBIA HEXAGONA, SIX-ANGLE SPURGE	-	INV	G5	S2
HEUCHERA VILLOSA VAR. ARKANSANA, ARKANSAS ALUMROOT	3C	INV	G5T3Q	S3
HYDROCOTYLE AMERICANA, AMERICAN WATER-PENNYWORT	-	INV	G5	SH
MALUS CORONARIA, SWEET CRAB-APPLE	-	INV	G5	S2S3
MIMULUS FLORIBUNDUS, FLORIFEROUS MONKEYFLOWER	-	INV	G5	S2S3
NEVIUSIA ALABAMENSIS, ALABAMA SNOW WREATH	-	ST	G2	S1S2
OSMUNDA CLAYTONIANA, INTERRUPTED FERN	-	ST	G5	S1
PHILADELPHUS HIRSUTUS, A MOCK ORANGE	-	INV	G5	S2S3
PODOSTEMUM CERATOPHYLLUM, THREADFOOT	-	INV	G5	S3
SANICULA SMALLII, SMALL'S SANICLE	-	INV	G5	S3

ELEMENT NAME	FEDERAL STATUS	STATE STATUS	GLOBAL RANK	STATE RANK
SELAGINELLA ARENICOLA SSP. *RIDDELLII*, RIDDELL'S SPIKE MOSS	-	INV	G4T4	S3
SILENE OVATA, OVATE-LEAF CATCHFLY	-	ST	G3	S2
TRADESCANTIA OZARKANA, OZARK SPIDERWORT	-	INV	G2G3	S3
TRADESCANTIA SUBASPERA, A SPIDERWORT	-	INV	G5	S1S3
TRICHOMANES PETERSII, DWARF FILMY-FERN	-	ST	G4G5	S2
** Natural Communities				
MESIC OAK-HICKORY FOREST	-	INV	-	S4
OVERCUP OAK FOREST	-	INV	-	S2
RIVER FRONT FOREST	-	INV	-	S3
SANDSTONE GLADE/OUTCROP	-	INV	-	S4
TALLGRASS PRAIRIE	-	INV	-	S2
UPLAND STREAM-OZARK MOUNTAINS	-	INV	-	-
** Other				
COLONIAL NESTING SITE, COLONIAL WATER BIRDS	-	INV	-	-
GEOLOGICAL FEATURE	-	INV	-	-

LEGEND

FEDERAL STATUS CODES

C1 = Category 1; the U.S. Fish and Wildlife Service states it currently has substantial information on hand that supports listing these species as threatened or endangered.

C2 = Category 2; the U.S. Fish and Wildlife Service states that further biological research and field study will be necessary in order to determine if these species should be listed as threatened or endangered (AS OF FEBRUARY 28, 1996 THE U.S. FISH & WILDLIFE SERVICE WILL NO LONGER MAINTAIN A LIST OF CATEGORY 2 SPECIES)

3C = These species have been reviewed by the U.S. Fish and Wildlife Service and the determination has been made that special designation is not warranted.

3B = Names that, on the basis of current taxonomic understanding (usually as represented in published revisions and monographs) do not represent distinct taxa meeting the Endangered Species Act's definition of "species." Such supposed taxa could be reevaluated in the future on the basis of new information.

LE = Listed Endangered; the U.S. Fish and Wildlife Service has listed these species as endangered.

LT = Listed Threatened; the U.S. Fish and Wildlife Service has listed these species as threatened.

LELT = Listed Endangered and Threatened; the U.S. Fish and Wildlife Services has listed these species as endangered and threatened in different parts of the breeding range.

PE = Proposed Endangered; the U.S. Fish and Wildlife Service has proposed these species for listing as endangered.

PT = Proposed Threatened; the U.S. Fish and Wildlife Service has proposed these species for listing as threatened.

T/SA = E/SA Threatened (or Endangered) because of similarity of appearance.

STATE STATUS CODES

INV = Inventory Element; The Arkansas Natural Heritage Commission is currently conducting inventory work on these elements to determine their status in the state. These elements may include outstanding examples of Natural Communities, colonial nesting sites, outstanding scenic and geologic features as well as plants and animals which, according to current information, may be rare, peripheral, or of an undetermined status in the state.

SE = State Endangered; The Arkansas Natural Heritage Commission applies this term to native taxa which are in danger of being extirpated from the state.

ST = State Threatened; The Arkansas Natural Heritage Commission applies this term to native taxa which are believed likely to become endangered in Arkansas in the foreseeable future, based on current inventory information.

DEFINITION OF RANKS

Global Ranks

G1 = Critically imperiled globally because of extreme rarity (5 or fewer occurrences or very few remaining individuals or acres) or because of some factor(s) making it especially vulnerable to extinction.

G2 = Imperiled globally because of rarity (6-20 occurrences or few remaining individuals or acres) or because of some factor(s) making it especially vulnerable to extinction.

ARKANSAS NATURAL HERITAGE COMMISSION
1500 TOWER BUILDING
323 CENTER STREET
LITTLE ROCK, ARKANSAS 72201

Harold K. Grimmett
Director

Mike Huckabee
Governor

Date: September 29, 1999
Subject: Elements of Special Concern
Existing Transmission Line Corridors
Arkansas Nuclear One
ANHC No.: P-CF..-99-079

Dr. Gary Tucker
FTN Associates, Ltd.
3 Innwood Circle, Suite 220
Little Rock, AR 72211

Dear Dr. Tucker:

Staff members of the Arkansas Natural Heritage Commission have reviewed our files for records indicating the occurrence of rare plants and animals, outstanding natural communities, natural or scenic rivers, or other elements of special concern within the footprint of Arkansas Nuclear One's existing transmission line corridors. The results of this search are presented on your map and the enclosed data print-out. A legend is provided to help you interpret the codes on the print-out.

Our records indicate the potential occurrence of three species of state concern within the transmission line corridor: a mock orange (Philadelphus hirsutus), Ozark chinquapin (Castanea pumila var. ozarkensis), and Bachman's sparrow (Aimophila aestivalis). Mock orange is an uncommon species in the state where its distribution is disjunct from its eastern range. It is known principally from the Ozark region in Arkansas. Ozark chinquapin can still be found in relatively large numbers, but is of concern because of decline due to chestnut blight. Bachman's sparrow is a regular summer resident and can be locally common in successional pine habitat. It is of interest because of rangewide declines.

Three other locations along the transmission corridors are of interest to this agency: Illinois Bayou, Cadron Creek, and Goose Pond Natural Area. Portions of the Illinois Bayou and Cadron Creek are listed on the state Registry of Natural and Scenic Rivers and are considered "Extraordinary Resource Waters" by the Arkansas Department of Environmental Quality. Transmission line corridors cross each of these streams within the designated portions one time. The transmission lines also cross a corner of Goose Pond Natural Area. The Arkansas Natural Heritage Commission holds a conservation easement on this area. It is contained within the Ed Gordon/Point Remove Wildlife Managment Area managed by the Arkansas Game and Fish Commission. A boundary map of the Natural Area boundaries is provided.

Yell, Logan, Johnson, Pope, Conway, Faulkner, and Pulaski County Element Lists are enclosed for your reference. Represented on these lists are elements for which we have records in these counties. You may refer to the enclosed legend for help interpreting the codes on these lists.

Please keep in mind that the project area may contain important natural features of which we are unaware. Staff members of the Arkansas Natural Heritage Commission have not conducted a field survey of the transmission line corridors. Our review is based on data available to the program at the time of the request. It should not be regarded as a final statement on the elements or areas under consideration, nor should it be substituted for on-site surveys required for environmental assessments. Because our files are updated constantly, you may want to check with us again at a later time.

Thank you for consulting us. It has been a pleasure to work with you on this study.

Sincerely,

Cindy Osborne

Cindy Osborne
Data Manager

Enclosures: Information Sheet and Legend
Your map, enriched
Data Print-out
Information Sheet on State Natural and Scenic Rivers
Boundary Map - Goose Pond Natural Area
7 County Element Lists - Yell, Logan, Johnson, Pope, Conway, Faulkner, Pulaski
Invoice

CLIENT CONTACT REPORT

Project/Client:	ANO 99 Support	**Date/Time:**	October 4, 1999
Topic:		**Phone:**	
Contact:	Cindy Osborne	**By:**	Gary E. Tucker
Firm:	Arkansas Natural Heritage Comm.	**Date:**	
Address:	1500 Tower Bldg., 323 Center	**Referral:**	
City State Zip:	Little Rock, AR 72201		

Remarks:

Today we received a letter from Ms. Osborne, Arkansas Natural Heritage Commission (ANHC), dated September 29, 1999 and addressed to me, in which she included (1) a map of element occurrences, (2) data printout, (3) information sheet on state natural and scenic rivers, (4) boundary map of a state natural area, and (5) county element lists for Yell, Logan, Johnson, Pope, Conway, Faulkner, and Pulaski counties.

After a re-evaluation of the information requested from her — and a full evaluation of information received from her, it was determined that (1) there are no species element occurrence records related to the ANO Unit 1 500/161 kV transmission lines. Each of the species element occurrence records mentioned in her letter is associated with the ANO Unit 2 500 kV line from ANO to Mayflower and Mablevale. The status of Illinois Bayou as listed stream on the Registry of Natural and Scenic Rivers and as an extraordinary resource water, as designated by Arkansas Department of Environmental Quality, is indicated in the letter. Each of these designations was applied to Illinois Bayou after installation of the transmission lines, and because the request for relicensing of ANO Unit 1 involves no new construction of transmission lines, these designations represent moot issues. The important conclusion to derive from Ms. Osborne's letter is that there are NO KNOWN LOCATIONS for species of concern which are tracked by ANHC for ANO Unit 1, which is the subject of the relicensing effort.

	Routing	**Reviewed**	**Comments/Action**
1	BMW	RW	
2			
3			
4			
5			

Disposition: **Discard** **File** 6045-061 ANO 99 Support

For Filing Only: ☐ **Contact/Correspondence** ☐ **Contract** ☐ **Proposal** ☐ **Other**

CLIENT CONTACT REPORT

Project/Client:	ANO Relicensing	**Date/Time:**	October 13, 1999
Topic:		**Phone:**	
Contact:	Cindy Osborne	**By:**	Gary E. Tucker
Firm:	Arkansas Natural Heritage Comm.	**Date:**	
Address:	1500 Tower Bldg., 323 Center	**Referral:**	
City State Zip:	Little Rock, AR 72201		

Remarks:

I contacted Ms. Osborne to follow up on her August 19, 1997 letter addressed to me and regarding elements of special concern at the Arkansas Nuclear One (ANO) facility. She indicated that (1) there have been no additional records pertaining to the ANO site which have been added to their database since August 1997, and (2) Arkansas Natural Heritage Commission has no regulatory authority to require a landowner to conduct a field survey on the owner's property. I told her that the ANO site represents an industrial site which has experienced major alteration of its original vegetation cover, and the chances of finding occurrences of elements of special concern would appear to be remote and probably not justify a formal survey. She said she could agree with that viewpoint.

	Routing	Reviewed	Comments/Action
1	BMW		
2			
3			
4			
5			

Disposition: **Discard** **File** 6045-061 ANO 99 Support

For Filing Only: ☐ **Contact/Correspondence** ☐ **Contract** ☐ **Proposal** ☐ **Other**________________

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Attachment E

Arkansas Game and Fish Commission Correspondence:

Letter from Mr. Gary E. Tucker, FTN Associates to Mr. Craig Uyeda, Arkansas Game and Fish Commission, dated September 2, 1999

ftn Associates Ltd.
water resources / environmental consultants

RECEIVED
SEP 07 1999
RIVER BASINS

September 2, 1999

Mr. Craig Uyeda, River Basins
Arkansas Game and Fish Commission
2 Natural Resources Drive
Little Rock, AR 72205

RE: Request for Information on Federally Listed Threatened and Endangered Species and Other Wildlife Species Issues, Application for Extension of Nuclear Regulatory Commission License Period, Arkansas Nuclear One Facility, near Russellville, Pope County, Arkansas
FTN No. 6045-061

Dear Mr. Uyeda:

The purpose of this letter is to follow up on our phone conversation of August 26, 1999 regarding Entergy's Arkansas Nuclear One (ANO) facility permitting issues. You will recall from our conversation that I said we soon would be providing a request for information regarding the potential occurrence of federally listed threatened and endangered species and other wildlife species issues within ANO's existing transmission line corridors. The enclosed map provides you with approximate corridor locations.

Following construction of the original power generating facilities and transmission lines, ANO went online in 1974 by authorization of a license issued by Nuclear Regulatory Commission. That original license will expire in 2014, and Entergy is presently preparing an application for an extension of existing operations until 2034. Please note that the application solely addresses a continuation of existing operations and does not involve any new construction or other deviation from the *status quo*.

If you have questions or need additional information, please feel free to call me or Bob West at (501) 225-7779.

Kindest regards,
FTN ASSOCIATES, LTD.

Bob West For
Gary E. Tucker, PhD, PWS
Environmental Scientist

Enclosure

CC: Rick Buckley - Entergy

P:\WP_FILES\6045-061\L-UYEDA.WPD\BMW

ARKANSAS GAME & FISH COMMISSION
Our records indicate no federally listed endangered and/or threatened fish and wildlife species occur in the project area.

Date: 10-12-99
Signed: Robert K Leonard

3 Innwood Circle • Suite 220 • Little Rock, AR 72211
(501) 225-7779 • Fax (501) 225-6738
2949 Point Circle • Suite 1 • Fayetteville, AR 72704
(501) 571-3334 • Fax (501) 571-3338
Web Site: www.ftn-assoc.com
E-mail: ftn@ftn-assoc.com

Attachment F

State Historic Preservation Office Correspondence:

Letter from Cathy Buford Slater, State Historic Preservation Officer, to Dr. Gary E. Tucker, FTN Associates, Ltd., dated March 30, 1998

Personal communication between George McCluskey State Historic Preservation Office (SHPO) and Dr. Gary E. Tucker, FTN Associates, Ltd., on April 1, 1998

Personal communication between George McCluskey State Historic Preservation Office (SHPO) and Dr. Gary E. Tucker, FTN Associates, Ltd., on April 2, 1998

Letter from Gary E. Tucker, FTN to George McCluskey State Historic Preservation Office, dated September 2, 1999

ARKANSAS
HISTORIC
PRESERVATION
PROGRAM

March 30, 1998

Dr. Gary E. Tucker
Environmental Scientist
FTN Associates, Ltd.
3 Innwood Circle, Suite 220
Little Rock, AR 72211

RE: Pope County - Russellville
Section 106 Review - NRC
Historic Properties Issues at Arkansas Nuclear
One Plant Site Near Russellville, Arkansas

Dear Dr. Tucker:

This letter is written in response to your inquiry regarding properties of archeological, historical, or architectural significance within the property boundary of the Arkansas Nuclear One (ANO) plant site near Russellville, Arkansas.

The staff of the Arkansas Historic Preservation Program has reviewed the records that pertain to the area in question. The staff has reported that five archeological sites (3PP62, 3PP63, 3PP65, 3PP66, and the May Cemetery) are located within the ANO property boundary. All five of these sites are potentially eligible for inclusion in the National Register of Historic Places. Other unknown archeological sites may also be present. Therefore, a master plan should consider potential impacts on historic properties that may result from the development or expansion of the Arkansas Nuclear One facility. A cultural resources survey to identify and evaluate historic properties, pursuant to Section 106 of the National Historic Preservation Act, may also be necessary.

Thank you for your interest and concern for the cultural heritage of Arkansas. If you have any questions, please contact George McCluskey of my staff at (501) 324-9880.

Sincerely,

Cathy Slater

Cathy Buford Slater
State Historic Preservation Officer

REC'D APR - 1 1998

CBS:GM

cc: Arkansas Archeological Survey

1500 Tower Building • 323 Center • Little Rock, Arkansas 72201 • Phone (501) 324-9880
Fax (501) 324-9184 • TDD (501) 324-9811
A Division of the Department of Arkansas Heritage

LU4C-JLO ANC EIS

CLIENT CONTACT REPORT

Project/Client:	ANO EIS	**Date/Time:**	4/1/98
Topic:		**Phone:**	
Contact:	George McCluskey	**By:**	GET
Firm:	SHPO	**Date:**	
Address:		**Referral:**	
City State Zip:			

Remarks:

Talked w/ George about letter from SHPO concerning ANO cultural resources issues. No systematic survey has been done in vicinity of plant. Pertinent cultural resources legislation dates from 1966 but state office really didn't get functional until around 1970. There was a limited amount of work done at time Lake Dardanelle was constructed. George said the May Cemetery probably has headstones and a fence and would be known to local people. The remaining sites are archeological and not be evident to casual observer. Little is known about any of sites and little indication as to whether they would be worthy of National Registert. SHPO does know that Cherokee sites were probably extensive in area but most now under water. He said map we sent was good enough that he was able to determine that none of archeological sites are close enough to existing facilities to be of concern. Ongoing "maintenance" is exempt from SHPO concerns. In event that ANO intends to erect new facilities or has major ground disturbing activities, they would need to contact SHPO for consultation. Normally it takes a permit to trigger SHPO involvement, i.e., something from Nuclear Regulatory Commission or Corps. As a part of re-licensing effort, he said Entergy "might want to write a letter to SHPO specifically indicating its intent to pursue re-licensing but without any new construction". In the event of future construction, they can write a letter and indicate where ground disturbing activities would be. SHPO could probably make its assessment from information provided. In this instance, George said there is no reason for concern. Section 106 refers to the regs that trigger SHPO review process....in event of permit application.

	Routing	Reviewed	Comments/Action
1	BMW	BW	
2	DEF	DF	
3			
4			
5			

Disposition: Discard File 6045-060 ANO EIS

For Filing Only: ☐ Contact/Correspondence ☐ Contract ☐ Proposal ☐ Other

CLIENT CONTACT REPORT

Project/Client:	ANO 99 Support	**Date/Time:**	April 2, 1998
Topic:		**Phone:**	
Contact:	George McCluskey	**By:**	Gary E. Tucker
Firm:	State Historic Preservation Office	**Date:**	
Address:	1500 Tower Building, 323 Center	**Referral:**	
City State Zip:	Little Rock, AR 72201		

Remarks:

Yesterday we received a letter from Cathy Slater, State Historic Preservation Officer (SHPO), in response to our query regarding the presence of potential cultural resources issues within the property boundary of Arkansas Nuclear One (ANO) facility. The letter indicated that a "cultural resources survey to identify and evaluate historic properties, pursuant to Section 106 of the National Historic Preservation Act, may also be necessary." I talked with George McCluskey, Senior Archeologist with SHPO, regarding the potential need for additional survey work for cultural resources issues. Mr. McCluskey indicated that a survey to satisfy Section 106 of the National Historic Preservation Act would not be required for the property, because the site is owned by Entergy and not by the federal government. He said in the event that Entergy intends to conduct ground disturbing activities, a survey might be useful to Entergy to ensure that cultural resources are not adversely impacted. The application for relicensing of ANO Unit 1 involves no ground disturbing activities but instead represents a request for extension of the permit for the *status quo,* therefore, in the absence of a request for authorization of ground disturbing activities no survey would be required.

	Routing	Reviewed	Comments/Action
1	BMW	TWS	
2			
3			
4			
5			

Disposition: **Discard** **File** 6045-061 ANO 99 Support

For Filing Only: ☐ **Contact/Correspondence** ☐ **Contract** ☐ **Proposal** ☐ **Other**__________

ftn Associates Ltd.
water resources / environmental consultants

RECD OCT 12 1999 NRC
AHPP
OCT 6 - 1999 39349

September 2, 1999

Mr. George McCluskey
Senior Archeologist
State Historic Preservation Office
1500 Tower Building, 323 Center
Little Rock, AR 72201

RE: Cultural Resources Issues, Application for Extension of Nuclear Regulatory Commission License Period, Arkansas Nuclear One Facility, near Russellville, Pope County, Arkansas
FTN No. 6045-061

Dear Mr. McCluskey:

The purpose of this letter is to follow up on our recent phone conversation regarding ongoing relicensing issues related to Entergy's Arkansas Nuclear One (ANO) facility. Following construction of the original power generating facilities and transmission lines, ANO went online in 1974 by authorization of a license issued by Nuclear Regulatory Commission. That original license will expire in 2014, and Entergy is presently preparing an application for an extension of existing operations until 2034. That application, which again will be submitted to NRC, solely addresses a continuation of existing operations and does not involve any new construction or other deviation from the *status quo*.

We have corresponded with you previously regarding cultural resources issues within the boundaries of the power generating facilities, and you provided information regarding cultural resources sites in a letter to us dated June 18, 1999. At this time, however, we are requesting additional information from you regarding any potential impacts on cultural resources related to transmission line corridors leading from the ANO facility to points near Danville, Russellville, Morrilton, and Mabelvale, respectively. The enclosed map provides approximate locations for the transmission line corridors.

Please provide us with a written response as to whether you will require any cultural resources records searches or field surveys for areas located within the transmission line corridors. Again, we want to emphasize the fact that the current application to NRC involves no new construction or replacement of existing transmission lines. Instead, the application is concerned only with a request for an extension of the licensing period, i.e., until 2034, for the ANO facility.

If you have questions or need additional information, please feel free to call me or Bob West at (501) 225-7779.

Kindest regards,
FTN ASSOCIATES, LTD.

Bob West For

Gary E. Tucker, PhD, PWS
Environmental Scientist

Enclosure

cc: Rick Buckley - Entergy
P:\WP_FILES\6045-061\L-GEORGE.WPD

Date 10/6/99
This undertaking will have no effect on significant historic properties.
Cathy Buford Slater
State Historic Preservation Officer

3 Innwood Circle • Suite 220 • Little Rock, AR 72211
(501) 225-7779 • Fax (501) 225-6738
2949 Point Circle • Suite 1 • Fayetteville, AR 72704
(501) 571-3334 • Fax (501) 571-3338
Web Site: www.ftn-assoc.com
E-mail: ftn@ftn-assoc.com

Attachment G

SEVERE ACCIDENT MITIGATION ALTERNATIVES ANALYSIS

Attachment G contains the following sections:

- G.1 – Melcor Accident Consequences Code System Modeling
- G.2 – Evaluation of Candidate SAMAs
- G.3 – Acronyms Used in Attachment G

G.1 MELCOR ACCIDENT CONSEQUENCES CODE SYSTEM MODELING

G.1.1 Introduction

The following sections describe the assumptions made and the results of modeling performed to assess the risks and consequences of severe accidents (U.S. NRC Class 9) at ANO-1.

The severe accident consequence analysis was carried out with the Melcor Accident Consequence Code System (Reference G.1-1). MACCS2 simulates the impact of severe accidents at nuclear power plants on the surrounding environment. The principal phenomena considered in MACCS2 are atmospheric transport, mitigating actions based on dose projection, dose accumulation by a number of pathways including food and water ingestion, early and latent health effects, and economic costs.

G.1.2 Input

The input data required by MACCS2 are outlined below.

G.1.2.1 CORE INVENTORY

The core inventory (Table G.1-1) is for ANO-1 at a power level of 2568 megawatts-thermal. These values were obtained by adjusting the end-of-cycle values for a 3,412 megawatts-thermal pressurized water reactor by a linear scaling factor of 0.753 (Reference G.1-1).

G.1.2.2 SOURCE TERMS

The source term input data to MACCS2 were the severe accident source terms presented in the probabilistic risk assessment in the ANO-1 IPE (Reference G.1-2). This document defines the releases in terms of release modes and demonstrates the method of calculating releases. There are 53 release modes: 20 with early containment failure, 27 with late containment failure, and 6 with containment bypass as the failure mode. Table G.1-2 lists the input release fractions for each MACCS2 nuclide group together with the source category frequencies as calculated in the probabilistic risk assessment. For all modes the Ruthenium, Lanthanum, Cerium, and Barium fractions of the usual MACCS2 species are set to zero, as they were not reported in the IPE submittal. The assignment of the radionuclides in Table G.1-1 to these nuclide groups is the same as that given in the standard MACCS2 input. Where other related source term data were not reported, such as release durations and energies, these were evaluated by comparison with similar releases reported in the NUREG-1150 studies for the Surry plant (Reference G.1-3).

The amounts (becquerels) of each radionuclide released to the atmosphere for each accident sequence or release category are obtained by multiplying the (adjusted) core inventory at the time of the hypothetical accident (Table G.1-1) by the release fractions (Table G.1-2) assigned to each of the nuclide groups.

The offsite consequences are summed for all the release modes weighted by the annual frequency to obtain the total annual accident risk, for the base case and for each of the SAMA concepts evaluated. (This summation calculation is performed outside of the MACCS2 code as part of the SAMA cost benefit analyses.)

G.1.2.3 METEOROLOGICAL DATA

The MACCS2 input uses a full year of consecutive hourly values of windspeed, wind direction, stability class, and precipitation. This file describes one year's (1996) worth of hourly meteorological data for the plant as recorded at the site meteorological tower. However the site did not record precipitation data for this year. Precipitation data for this year was therefore obtained for the nearest available recording site. The data obtained was the hourly precipitation recorded for 1996 at Clarksville 6 NE COOP Station 03157 located at 35 deg 32 min N, 93 deg 24 min W. (about 20 miles NW of the plant site) (Reference G.1-4). The seasonal mixing heights for this area of Arkansas were taken from maps of mixing heights for the US.

MACCS2 calculations examine a representative subset of the 8,760 hourly observations contained in one year’s data set (typically about 150 sequences). The representative subset is selected by sampling the weather sequences after sorting them into weather bins defined by windspeed, atmospheric stability, and rain conditions at various distances from the site.

G.1.2.4 POPULATION DISTRIBUTION

The predicted permanent resident population around the site for the year 2025 was distributed by location in a grid consisting of sixteen directional sectors, the first of which is centered on due north, the second on 22.5 degrees east of north, and so on. A summary of the population distribution is shown in Table G.1-3. The direction sectors were divided into 15 radial intervals extending out to 50 miles. The habitable land fraction for each grid element was calculated from land fraction data within a 50-mile radius of the plant.

The computer program SECPOP90 (Reference G.1-5) was used to process block-level 1990 census data (Reference G.1-6), as extracted in part to SECPOP90 data files, to prepare population estimates for the region surrounding the plant. The SECPOP90 census data file contains a record for the location (geometric centroid coordinates) and the population of each census block (6,660,337 records) in the continental U.S. If the centroid point met the distance criteria, it was then processed to determine the exact grid element in which it lies based on its radial distance and direction from the site. The population associated with that data point was then added to the population of that grid section. This process produced the raw 1990 population estimate for each rosette section. To these were added the transient populations in the emergency planning zone (exclusion boundary of 0.65 miles out to 10 miles) given in the Site Emergency Plan as estimated on a yearly average basis for each sector. The area is a popular recreational zone and it was considered appropriate to add in these people for dose purposes even if it results in an overestimate of the economic costs for non-farm property in this area.

The county-wide 1998 population estimates (Reference G.1-7) were then utilized to update the 1990 estimates to 1998. For each rosette section, the fraction of its area in each county was estimated. These fractions were then used to calculate a county-area weighted population growth factor (1998 county population divided by 1990 county population) for the section. The 1990 section population was then multiplied by this growth factor to produce the 1998 population estimate for that section.

The state-wide 1995-2025 Bureau of the Census data (Reference G.1-8) were then used to project the future rosette section populations for the year 2025. A statewide growth factor was calculated by dividing the state population projection for that year by the 1998 state population estimate. The section population projection for this step year was then calculated by multiplying the 1998 section population by the state growth factor.

Year 2025 population projections were used for the MACCS2 analyses as these are the endmost data produced by the Bureau of the Census and because it is about the midterm year of the proposed license extension period. It should be also noted that the MACCS2 population includes transient population estimates in the 10-mile zone around the plant as explained above in the EARLY file discussion. Hence the data in the MACCS2 site file are slightly larger in this zone that may be shown elsewhere in Tables of Population Projections for the ANO region.

G.1.2.5 EMERGENCY RESPONSE

Entergy Operations has a plan for the evacuation of the population within the plume exposure emergency planning zone. This zone is approximately a 10-mile radius centered on the ANO site. A site-specific evacuation study was been carried out by Entergy Operations (Reference G.1-9), and the evacuation modeling employed for the severe accident analysis was based primarily on this study.

The emergency evacuation model was modeled as a single radial evacuation zone extending out 10 miles from the plant. In the plan, it is stated that 80% of people will start moving 90 minutes after the alarm rings, 15% of the people will start moving 45 minutes after the alarm rings, and 5% of the people will start moving 135 minutes after the alarm rings. The clear times for each of the four zones were calculated by using weighted averages of the plan clear times for four different time periods, weekday, night, weekend, and adverse weekday. The average evacuation speed for the emergency zone was then estimated using the population-weighted average of the evacuation speed of each planning zone.

Because of the recreational nature of the area immediately surrounding the plant, the population in the emergency zone was augmented by adding the transient population to the census-based resident population. An average evacuation start time delay of 5130 seconds and an average radial evacuation speed of 1 m/s were estimated in the above manner.

For this analysis it was conservatively assumed that people beyond 10 miles would continue their normal activities unless the following predicted radiation dose levels are exceeded. At locations for which 50 rem whole body effective dose equivalent in one week is predicted, it was assumed that relocation would take place after half a day. If 25 rem whole body dose equivalent in one week is predicted, relocation of individuals in those sectors was assumed to take place after one day.

A sensitivity analysis was performed in which it was assumed that only 95 percent of the people within the emergency planning zone would participate in the evacuation. The remaining 5% were assumed to be unable or unwilling to evacuate and were assumed to go about their normal activities. The results were not significantly different on the whole from the complete evacuation case, for the purposes of the SAMA analyses. While the population doses increased and the evacuation costs decreased, the overall population exposure and accident mitigation costs are governed mainly by the long term effects over the whole 50-mile zone, and so the net changes were small, about one percent, which is not considered significant.

Another sensitivity analysis was performed to assess the importance of the calculated warning and release delay times. An arbitrary two hours was subtracted from all of the base case alarm and delay times, except the late release start time was decreased from 150,000 seconds to 86,400 seconds to effect a comparable change. The overall results were quantitatively quite similar to the evacuation effectiveness case of the preceding paragraph, with changes on the order of one percent.

The long-term phase was assumed to begin after one week and extend for five years. Long-term relocation was assumed to be triggered by a 4 rem whole body effective dose equivalent. Long-term protective measures were assumed to be based on generic protective action guideline levels for actions such as decontamination, temporary relocation, contaminated crops, and milk condemnation, and farmland production prohibition.

G.1.2.6 ECONOMIC DATA

Land use statistics including farmland values, farm product values, dairy production, and growing season information were provided on a countywide basis within 50 miles.

Much of the data was prepared by the computer program SECPOP90 (Reference G.1-5). It contains a database extracted from Bureau of the Census PL 94-171 (block level census) CD-ROMS (Reference G.1-6), the 1992 Census of Agriculture CD ROM Series 1B, the 1994 U.S. Census County and City Data Book CD-ROM, the 1993 and 1994 Statistical Abstract of the United States, and other minor sources. The reference contains details on how the database was created and checked. The SECPOP90 regional economic values were updated to 1997 using the Consumer Price Index (Reference G.1-10) and other data from the Bureau of the Census and the Department of Agriculture (Reference G.1-11).

Economic consequences were estimated by summing the following costs:

- Costs of evacuation,
- Costs for temporary relocation (food, lodging, lost income),
- Costs of decontaminating land and buildings,
- Lost return-on-investments from properties that are temporarily interdicted to allow contamination to be decreased by decay of nuclides,
- Costs of repairing temporarily interdicted property,
- Value of crops destroyed or not grown because they were contaminated by direct deposition or would be contaminated by root uptake, and
- Value of farmland and of individual, public, and non-farm commercial property that is condemned.

Costs associated with damage to the reactor, the purchase of replacement power, medical care, life-shortening, and litigation are not calculated by MACCS2.

G.1.3 Results

Based on the preceding input data, MACCS2 was used to estimate the following:

- The downwind transport, dispersion, and deposition of the radioactive materials released to the atmosphere from the failed reactor containment.
- The short-term and long-term radiation doses received by exposed populations via direct (cloudshine, plume inhalation, groundshine, and resuspension inhalation) and indirect (ingestion) pathways.
- The mitigation of those doses by protective actions (evacuation, sheltering, and post-accident relocation of people; disposal of milk, meat, and crops; and decontamination, temporary interdiction, or condemnation of land and buildings).
- The early fatalities and injuries expected to occur within one year of the accident (early health effects) and the delayed (latent) cancer fatalities and injuries expected to occur over the lifetime of the exposed individuals.

- The offsite costs of short-term emergency response actions (evacuation, sheltering, and relocation), of crop and milk disposal, and of the decontamination, temporary interdiction, or condemnation of land and buildings.

The consequences calculated with the MACCS2 model in terms of the population dose and offsite economic costs for the SAMA base case and the two evacuation-model sensitivity cases (95% EVACUATION and 2 HOUR) are shown in Table G.1-4. A common way in which this combination of factors is used to estimate risk is to multiply the frequencies by the consequences. The resultant risk is then expressed as the number, or magnitude, of consequences expected per unit time. Table G.1-5 shows average values of risk. These average values were obtained by summing the frequency multiplied by the consequences over the entire range of distributions. Because the probabilities are on a per reactor-year basis, the averages shown are also on a per reactor-year basis. A value of $2000 per rem and a discount factor of 7% per year were used to obtain the 20-year values.

Table G.1-1. ANO-1 Core Inventory.[1]

Nuclide	Core inventory (becquerels)	Nuclide	Core inventory (becquerels)
Cobalt-58	2.43E+16	Tellurium-131M	3.52E+17
Cobalt-60	1.86E+16	Tellurium-132	3.51E+18
Krypton-85	1.86E+16	Iodine-131	2.41E+18
Krypton-85M	8.73E+17	Iodine-132	3.56E+18
Krypton-87	1.59E+18	Iodine-133	5.10E+18
Krypton-88	2.16E+18	Iodine-134	5.60E+18
Rubidium-86	1.42E+15	Iodine-135	4.81E+18
Strontium-89	2.70E+18	Xenon-133	5.11E+18
Strontium-90	1.46E+17	Xenon-135	9.59E+17
Strontium-91	3.48E+18	Cesium-134	3.26E+17
Strontium-92	3.62E+18	Cesium-136	9.91E+16
Yttrium-90	1.57E+17	Cesium-137	1.82E+17
Yttrium-91	3.29E+18	Barium-139	4.73E+18
Yttrium-92	3.63E+18	Barium-140	4.68E+18
Yttrium-93	4.11E+18	Lanthanum-140	4.78E+18
Zirconium-95	4.16E+18	Lanthanum-141	4.39E+18
Zirconium-97	4.34E+18	Lanthanum-142	4.23E+18
Niobium-95	3.93E+18	Cerium-141	4.26E+18
Molybdium-99	4.59E+18	Cerium-143	4.14E+18
Technetium-99M	3.96E+18	Cerium-144	2.56E+18
Ruthenium-103	3.42E+18	Praseodymium-143	4.06E+18
Ruthenium-105	2.22E+18	Neodymium-147	1.82E+18
Ruthenium-106	7.77E+17	Neptunium-239	4.87E+19
Rhodium-105	1.54E+18	Plutonium-238	2.76E+15
Antimony-127	2.10E+17	Plutonium-239	6.22E+14
Antimony-129	7.43E+17	Plutonium-240	7.85E+14
Tellurium-127	2.03E+17	Plutonium-241	1.32E+17
Tellurium-127M	2.68E+16	Americium-241	8.73E+13
Tellurium-129	6.98E+17	Curium-242	3.34E+16
Tellurium-129M	1.84E+17	Curium-244	1.95E+15

1 Reference G.1-1.

Table G.1-2 ANO-1 RELEASE FRACTION BY NUCLIDE GROUP [2]

Release Mode[3]	Frequency[4]	Xenon/ Krypton	Iodine	Cesium	Tellurium	Strontium
A1	6.52E-10	9.20E-01	1.07E-04	9.02E-05	2.99E-05	4.17E-07
A2	2.91E-12	9.20E-01	4.29E-03	3.61E-03	1.10E-01	1.67E-05
A3	2.76E-08	9.20E-01	6.83E-04	5.74E-04	1.91E-04	2.66E-06
A4	4.94E-08	9.20E-01	2.73E-02	2.30E-02	7.62E-03	1.06E-04
B1	2.39E-11	9.20E-01	2.64E-04	2.15E-04	5.99E-05	8.35E-07
B2-L	6.16E-13	9.20E-01	9.96E-03	8.18E-03	2.40E-03	3.34E-05
B2-R	5.29E-13	9.20E-01	9.96E-03	8.18E-03	2.40E-03	3.34E-05
B3-L	5.26E-09	9.20E-01	2.64E-04	2.15E-04	5.99E-05	8.35E-07
B3-R	2.81E-10	9.20E-01	2.64E-04	2.15E-04	5.99E-05	8.35E-07
B4-L	3.75E-11	9.20E-01	9.96E-03	9.18E-03	2.40E-03	3.34E-05
B4-R	6.28E-12	9.20E-01	9.96E-03	8.18E-03	2.40E-03	3.34E-05
B5-L	5.45E-09	9.20E-01	8.82E-04	4.76E-04	1.13E-04	1.57E-06
B5-R	2.91E-10	9.20E-01	8.82E-04	4.76E-04	1.13E-04	1.57E-06
B6-L	4.08E-11	9.20E-01	4.04E-03	2.29E-03	2.03E-04	2.83E-06
B6-R	7.13E-12	9.20E-01	4.04E-03	2.29E-03	2.03E-04	2.93E-06
BP-D3A	4.01E-08	7.44E-01	2.10E-02	2.13E-02	1.51E-02	1.38E-04
BP-D3B	4.01E-08	9.20E-01	2.18E-01	2.21E-01	5.86E-02	1.14E-03
BP-E5A	1.00E-08	8.24E-01	2.12E-02	2.14E-02	1.54E-02	1.38E-04
BP-E5B	1.00E-08	1.00E+00	2.23E-01	2.25E-01	6.56E-02	1.14E-03
BP-E6A	3.56E-08	8.24E-01	2.84E-02	2.60E-02	2.43E-02	1.42E-04
BP-E6B	2.23E-07	1.00E+00	3.89E-01	3.43E-01	2.58E-01	1.16E-03
C1-L	4.42E-09	1.00E+00	6.39E-04	4.85E-04	1.06E-03	8.35E-07
C1-R	2.36E-10	1.00E+00	6.39E-04	4.85E-04	1.06E-03	8.35E-07
C2-L	2.34E-11	1.00E+00	1.03E-02	8.45E-03	4.26E-03	3.34E-05
C2-R	5.52E-12	1.00E+00	1.03E-02	8.45E-03	4.26E-03	3.34E-05
C3-L	3.95E-07	1.00E+00	6.39E-04	4.85E-04	1.06E-03	8.35E-07
C3-R	2.07E-08	1.00E+00	6.39E-04	4.85E-04	1.06E-03	8.35E-07
C4-L	1.03E-07	1.00E+00	2.12E-02	1.63E-02	3.03E-02	3.34E-05
C4-R	5.43E-09	1.00E+00	2.12E-02	1.63E-02	3.03E-02	3.34E-05

2 Reference G.1-2.

3 Release Modes notation:

A, B, C = late releases.

BP = bypass release modes

D, E = early releases

-R = containment rupture

-L = containment leak

4 Release Mode frequency per reactor year.

Table G.1-2 ANO-1 RELEASE FRACTION BY NUCLIDE GROUP [2]

Release Mode[3]	Frequency[4]	Xenon/ Krypton	Iodine	Cesium	Tellurium	Strontium
C5-L	2.70E-08	1.00E+00	1.26E-03	7.46E-04	1.11E-03	1.57E-06
C5-R	1.43E-09	1.00E+00	1.26E-03	7.46E-04	1.11E-03	1.57E-06
C6-L	7.39E-07	1.00E+00	1.53E-02	1.04E-02	2.81E-02	2.83E-06
C6-R	3.89E-08	1.00E+00	1.53E-02	1.04E-02	2.81E-02	2.83E-06
D1-L	9.14E-09	9.20E-01	1.41E-03	1.18E-03	3.81E-04	5.31E-06
D1-R	1.40E-08	9.20E-01	5.70E-03	4.79E-03	1.58E-03	2.20E-05
D2-L	1.72E-08	9.20E-01	5.60E-02	4.69E-02	1.52E-02	2.13E-04
D2-R	2.97E-08	9.20E-01	2.28E-01	1.91E-01	6.32E-02	8.80E-04
D3-L	3.70E-08	9.20E-01	5.11E-03	2.73E-03	7.19E-04	1.00E-05
D3-R	3.75E-08	9.41E-01	5.62E-02	3.66E-02	2.36E-02	3.41E-03
D4-L	7.51E-08	9.41E-01	2.02E-02	1.25E-02	6.27E-03	8.30E-04
D4-R	7.60E-08	9.41E-01	7.54E-02	4.70E-02	2.60E-02	3.44E-03
E1-L	2.10E-10	1.00E+00	2.66E-03	2.08E-03	2.37E-01	5.31E-06
E1-R	2.62E-10	1.00E+00	1.10E-02	8.57E-03	8.61E-03	2.20E-05
E2-L	3.86E-10	1.00E+00	5.72E-02	4.78E-02	1.90E-02	2.13E-04
E2-R	4.84E-10	1.00E+00	2.33E-01	1.95E-01	7.63E-02	9.90E-04
E3-L	6.08E-09	1.00E+00	2.66E-03	2.08E-03	2.37E-03	5.31E-06
E3-R	9.58E-09	1.00E+00	1.10E-02	9.57E-03	8.61E-03	2.20E-05
E4-L	4.50E-08	1.00E+00	9.35E-02	7.39E-02	7.11E-02	2.13E-04
E4-R	5.61E-08	1.00E+00	3.85E-01	3.05E-01	2.60E-01	8.80E-04
E5-L	9.27E-09	1.00E+00	6.36E-03	3.63E-03	2.71E-03	1.00E-05
E5-R	9.38E-09	1.00E+00	6.01E-02	3.94E-02	2.87E-02	3.41E-03
E6-L	5.46E-08	1.00E+00	4.77E-02	3.13E-02	4.73E-02	8.30E-04
E6-R	5.77E-08	1.00E+00	1.91E-01	1.30E-01	1.71E-01	3.44E-03

Table G.1-3. ANO-1 Regional Population Distribution (With Emergency Zone Transient Population)

	0-10 Miles	10-20 Miles	20-30 Miles	30-40 Miles	40-50 Miles	TOTALS
N	1,745	1,196	412	408	2,149	**5,910**
NNE	2,579	4,480	313	441	954	**8,767**
NE	17,156	5,376	2,240	421	1,532	**26,725**
ENE	13,361	3,469	2,349	2,146	5,630	**26,955**
E	5,757	6,702	10,460	5,911	25,094	**53,924**
ESE	5,235	742	5,567	3,825	44,444	**59,813**
SE	2,530	1,038	1,516	2,120	3,844	**11,048**
SSE	1,299	814	385	5,388	14,322	**22,208**
S	2,493	2,365	199	907	10,749	**16,713**
SSW	1,806	1,557	585	562	2,204	**6,714**
SW	644	3,514	716	714	697	**6,285**
WSW	366	1,326	1,023	1,391	1,593	**5,699**
W	67	275	5,878	9,327	7,572	**23,119**
WNW	1,240	2,068	5,173	11,604	4,735	**24,820**
NW	836	2,665	11,696	2,135	1,544	**18,876**
NNW	1,534	3,871	2,760	869	808	**9,841**
TOTALS	**58,648**	**41,458**	**51,272**	**48,169**	**127,871**	**327,418**

Table G.1-4 Summary of Offsite Consequence Results for Each Release Mode

	Population Dose, Sieverts			Offsite Economic Costs, $		
CET End Point (Release Mode)	Base	95% Evacuation	-2HR Alarm and Warning	Base	95% Evacuation	-2HR Alarm and Warning
A1	9.81E+01	9.84E+01	9.86E+01	4.02E+06	2.11E+06	4.04E+06
A2	9.77E+02	9.80E+02	9.75E+02	1.03E+08	1.01E+08	1.03E+08
A3	3.62E+02	3.63E+02	3.60E+02	2.46E+07	2.27E+07	2.49E+07
A4	2.40E+03	2.42E+03	2.41E+03	4.06E+08	4.05E+08	4.07E+08
B1	1.90E+02	1.91E+02	1.91E+02	8.82E+06	6.91E+06	9.01E+06
B2-L	1.46E+03	1.47E+03	1.44E+03	1.95E+08	1.93E+08	1.98E+08
B2-R	1.46E+03	1.47E+03	1.44E+03	1.95E+08	1.93E+08	1.98E+08
B3-L	1.90E+02	1.91E+02	1.91E+02	8.82E+06	6.91E+06	9.01E+06
B3-R	1.90E+02	1.91E+02	1.91E+02	8.82E+06	6.91E+06	9.01E+06
B4-L	1.46E+03	1.47E+03	1.44E+03	1.95E+08	1.93E+08	1.98E+08
B4-R	1.46E+03	1.47E+03	1.44E+03	1.95E+08	1.93E+08	1.98E+08
B5-L	3.24E+02	3.25E+02	3.24E+02	2.10E+07	1.91E+07	2.16E+07
B5-R	3.24E+02	3.25E+02	3.24E+02	2.10E+07	1.91E+07	2.16E+07
B6-L	7.17E+02	7.19E+02	7.17E+02	8.67E+07	8.49E+07	8.61E+07
B6-R	7.31E+02	7.34E+02	7.23E+02	7.96E+07	7.77E+07	8.12E+07
BP-D3A	1.90E+03	1.92E+03	1.91E+03	3.52E+08	3.52E+08	3.52E+08
BP-D3B	4.71E+03	4.80E+03	4.74E+03	1.07E+09	1.07E+09	1.07E+09
BP-E5A	1.91E+03	1.92E+03	1.92E+03	3.53E+08	3.53E+08	3.53E+08
BP-E5B	4.79E+03	4.88E+03	4.82E+03	1.07E+09	1.07E+09	1.07E+09
BP-E6A	2.08E+03	2.10E+03	2.09E+03	4.05E+08	4.05E+08	4.05E+08
BP-E6B	6.92E+03	7.11E+03	6.97E+03	1.23E+09	1.23E+09	1.23E+09
C1-L	3.35E+02	3.36E+02	3.27E+02	2.13E+07	1.94E+07	2.32E+07
C1-R	3.35E+02	3.36E+02	3.27E+02	2.13E+07	1.94E+07	2.32E+07
C2-L	1.47E+03	1.48E+03	1.48E+03	2.02E+08	2.00E+08	2.03E+08
C2-R	1.47E+03	1.48E+03	1.48E+03	2.02E+08	2.00E+08	2.03E+08
C3-L	3.35E+02	3.36E+02	3.27E+02	2.13E+07	1.94E+07	2.32E+07
C3-R	3.35E+02	3.36E+02	3.27E+02	2.13E+07	1.94E+07	2.32E+07
C4-L	2.09E+03	2.11E+03	2.11E+03	3.31E+08	3.30E+08	3.33E+08
C4-R	2.09E+03	2.11E+03	2.11E+03	3.31E+08	3.30E+08	3.33E+08
C5-L	4.12E+02	4.14E+02	4.15E+02	3.50E+07	3.31E+07	3.52E+07
C5-R	4.12E+02	4.14E+02	4.15E+02	3.50E+07	3.31E+07	3.52E+07
C6-L	1.76E+03	1.71E+03	1.72E+03	2.48E+08	2.40E+08	2.42E+08
C6-R	1.71E+03	1.72E+03	1.72E+03	2.40E+08	2.38E+08	2.41E+08
D1-L	5.39E+02	5.40E+02	5.39E+02	4.89E+07	4.71E+07	4.89E+07
D1-R	9.24E+02	9.27E+02	9.74E+02	1.24E+08	1.23E+08	1.24E+08
D2-L	2.96E+03	2.97E+03	2.96E+03	6.93E+08	6.92E+08	6.93E+08
D2-R	4.86E+03	4.92E+03	4.90E+03	1.03E+09	1.03E+09	1.03E+09
D3-L	7.76E+02	7.79E+02	7.76E+02	9.99E+07	9.80E+07	9.99E+07
D3-R	2.36E+03	2.38E+03	2.38E+03	5.45E+08	5.45E+08	5.45E+08
D4-L	1.86E+03	1.87E+03	1.86E+03	2.81E+08	2.79E+08	2.81E+08

Table G.1-4 Summary of Offsite Consequence Results for Each Release Mode

	Population Dose, Sieverts			Offsite Economic Costs, $		
CET End Point (Release Mode)	Base	95% Evacuation	-2HR Alarm and Warning	Base	95% Evacuation	-2HR Alarm and Warning
D4-R	2.62E+03	2.64E+03	2.64E+03	6.15E+08	6.15E+08	6.15E+08
E1-L	7.15E+02	7.19E+02	7.16E+02	7.74E+07	7.55E+07	7.74E+07
E1-R	1.32E+03	1.32E+03	1.33E+03	1.81E+08	1.80E+08	1.81E+08
E2-L	2.99E+03	3.00E+03	2.99E+03	7.01E+08	6.99E+08	7.01E+08
E2-R	4.98E+03	5.05E+03	5.02E+03	1.04E+09	1.04E+09	1.04E+09
E3-L	7.15E+02	7.19E+02	7.16E+02	7.74E+07	7.55E+07	7.74E+07
E3-R	1.38E+03	1.38E+03	1.38E+03	1.98E+08	1.98E+08	1.98E+08
E4-L	3.49E+03	3.52E+03	3.49E+03	8.96E+08	8.95E+08	8.97E+08
E4-R	7.38E+03	7.52E+03	7.46E+03	1.19E+09	1.19E+09	1.19E+09
E5-L	9.34E+02	9.39E+02	9.35E+02	1.18E+08	1.16E+08	1.18E+08
E5-R	2.45E+03	2.47E+03	2.47E+03	5.69E+08	5.68E+08	5.69E+08
E6-L	2.76E+03	2.78E+03	2.76E+03	5.42E+08	5.40E+08	5.42E+08
E6-R	4.52E+03	4.60E+03	4.57E+03	9.32E+08	9.32E+08	9.32E+08

Table G.1-5. Summed Average Risks

OFFSITE RISKS			
(Annual)	**BASE**	**95%EVAC**	**-2hr alrm**
REMS	0.5532	0.5568	0.5528
DOLLARS	$ 956	$ 949	$ 953
OFFSITE RISKS			
(20 year)	**BASE**	**95%EVAC**	**-2hr alrm**
EQ. REM	$ 11,908	$ 11,986	$11,899
DOLLARS	10,290	10,209	10,255
TOTALS	$ 22,198	$ 22,195	$22,153
DELTA From BASE		**95%EVAC**	**-2hr alrm**
$		$ (4)	$ (45)
%		-0.02%	-0.20%

G.1.4 References

G.1-1 *Code Manual for MACCS2: Volume 1, User's Guide*, Chanin, D. I., et al, SAND07-054, March 1997. SEE ALSO:

MACCS2 V.1.12, CCC-652 Code Package, ORNL (Oak Ridge National Laboratory RISCC Computer Code Collection), 1997.

MELCOR Accident Consequence Code System (MACCS) Model Description, Jow, H. N, et al, NUREG/CR-4691, SAND86-1562, February 1990.

G.1-2 *ANO-1 Probabilistic Risk Assessment Summary Repor*t, *IPE Submittal*, Entergy Operations, Inc., USNRC Docket # 05000313, April 1993.

G.1-3 *Evaluation of Severe Accident Risks: Surry 1 Main Report*, NUREG/CR-4551, Vol. 3, Rev. 1, Part 1, Breeding, R. J., et al, October 1990.

G.1-4 *1996 Hourly Precipitation Data for Clarksville 6 NE COOP ID 031457*, NCDC (National Climatic Data Center, National Oceanic and Atmospheric Administration), Order Num. 6394, May 7, 1999.

G.1-5 *SECPOP90: Sector Population, Land Fraction, and Economic Estimation Program*, NUREG/CR-6525, Humphreys, S. L., et al, September, 1997.

G.1-6 *Census of Population and Housing, 1990: Public Law (P. L.) 94-171, Data Technical Documentation*, CD – ROM set , BOC (Bureau of the Census, U. S. Dept. of Commerce), 1991.

G.1-7 *County Population Estimates for July 1, 1998 and Population Change for April 1, 1990 to July 1, 1998 (includes revised April 1, 1990 Census Population Counts)*, BOC (Bureau of the Census, Statistical Information Staff, Population Division), CO-98-002, Released to Internet, March 12, 1999.

G.1-8 *Population Projections: States, 1995-2025*, Census Bureau, U. S. Department of Commerce P25-1131, , BOC (Bureau of the Census), Campbell, Paul, May 1997.

G.1-9 *ANO Emergency Plan*, Entergy Operations, Inc., 1981.

G.1-10 *Consumer Price Index-All Urban Consumers*, Series Catalog: Series ID: CUUR0300SA0, BOL (U.S. Bureau of Labor), 1999.

G.1-11 *1997 Census of Agriculture*, DOA (U.S. Dept. of Agriculture, National Agricultural Statistics Service) 1997.

G.1-12 *Regional Population 2000-2030 Projections,* SCIENTECH, Inc. ANO-1 Project 17071 AF-2, Fulford, P. J., September 13, 1999.

G.1-13 *Evaluation of Severe Accident Risks: Quantification of Major Input Parameters MACCS Input,* NUREG/CR 4557, Vol. 2, Rev. 1., Part 7, Sprung, J. L. et al, December 1990.

G.2 EVALUATION OF CANDIDATE SAMAs

This section describes the generation of the initial list of potential SAMAs for ANO-1, screening methods and the analysis of the remaining SAMAs.

G.2.1 SAMA List Compilation

Entergy Operations generated a list of candidate SAMAs by reviewing industry documents and considering plant-specific enhancements not considered in published industry documents. Industry documents reviewed include the following:

- The ANO-1 IPE submittal (Reference 1 in Section G.2-5)
- The Watts Bar Nuclear Plant Unit 1 PRA/IPE submittal (Reference 2 in Section G.2-5)
- The Limerick SAMDA cost estimate report (Reference 3 in Section G.2-5)
- NUREG-1437 description of Limerick SAMDA (Reference 4 in Section G.2-5)
- NUREG-1437 description of Comanche Peak SAMDA (Reference 5 in Section G.2-5)
- Watts Bar SAMDA submittal (Reference 6 in Section G.2-5)
- TVA response to NRC's RAI on the Watts Bar SAMDA submittal (Reference 7 in Section G.2-5)
- Westinghouse AP600 SAMDA (Reference 8 in Section G.2-5)
- Safety Assessment Consulting (SAC) presentation by Wolfgang Werner at the NUREG 1560 conference (Reference 9 in Section G.2-5)
- NRC IPE Workshop - NUREG 1560 NRC Presentation (Reference 10 in Section G.2-5)
- NUREG 0498, supplement 1, section 7 (Reference 11 in Section G.2-5)
- NUREG/CR-5567, PWR Dry Containment Issue Characterization (Reference 12 in Section G.2-5)
- NUREG-1560, Volume 2, NRC Perspectives on the IPE Program (Reference 13 in Section G.2-5)
- NUREG/CR-5630, PWR Dry Containment Parametric Studies (Reference 14 in Section G.2-5)
- NUREG/CR-5575, Quantitative Analysis of Potential Performance Improvements for the Dry PWR Containment (Reference 15 in Section G.2-5)
- CE System 80+ Submittal (Reference 16 in Section G.2-5)
- NUREG 1462, NRC Review of ABB/CE System 80+ Submittal (Reference 17 in Section G.2-5)
- An ICONE paper by C. W. Forsberg, et. al, on a core melt source reduction system (Reference 18 in Section G.2-5)

Although ANO-1 is a B&W design, each of the above documents were reviewed for potential SAMAs even if they were not necessary applicable to a B&W plant. Those items not applicable to ANO-1 were subsequently screened from this list. The containment performance improvement programs for boiling water reactors and ice condenser plants were not reviewed (and the NUREG-1560 portion of the containment performance improvement for these were not reviewed). Conceptual enhancement for which no specific details were available (e.g., “improve diesel reliability” or “improve procedures for loss of support systems”) were not included, unless they were considered as vulnerabilities in the ANO-1 IPE.

G.2.2 Qualitative Screening of SAMAs

The initial list of potential SAMAs are presented in Table G.2-1. Table G.2-1 also presents a qualitative screening of the initial list. Items were eliminated from further evaluation based on one of the following criteria:

- The SAMA is not applicable at ANO-1, either because the enhancement is only for boiling water reactors, the Westinghouse AP600 design or PWR ice condenser containments, or it is a plant specific enhancement that does not apply at ANO-1 (Criterion A – Not applicable); or
- The SAMA has already been implemented at ANO-1 (or the ANO-1 design meets the intent of the SAMA) (Criterion B – Implemented or intent met).

Based on preliminary screening, 80 improvements were eliminated, leaving 89 subject to the final screening process (Criterion N – Not initially screened). These improvements are listed in Table G.2-2.

The final screening process involved identifying and eliminating those items whose cost exceeded their benefit. Table G.2-2 provides a description of the evaluation of each and provides the basis for their elimination or describes their final resolution.

G.2.3 Analysis of Potential SAMAs

The approach selected for this portion of the analysis (potential SAMAs to reduce core damage frequency) is to calculate the value of the averted risk to the public for each alternative. It relies on the NRC’s handbook (Reference 20 in Section G.2-5) to convert public health risk (person-rem) into dollars to estimate the cost of the public health consequences. The requirement established in this handbook is to use $2,000 per person-rem to convert public health consequences to dollars (not indexed to inflation). Therefore, the value (or safety improvement) of implementing an alternative is expressed in terms of averted cost to the public (public benefit). It should be noted that the maximum attainable benefit for any improvement is, hypothetically, the elimination of all plant risk. The expected cost of some SAMAs exceed this benefit and can be eliminated on this basis in the cost-benefit analysis.

The evaluation process described in Reference 20 of Section G.2-5 calculates the value of averted risk on an annual basis. Therefore, a method of “discounting” is used to calculate the “present value” or “present worth of averted risk” based on a specified period of time. For this analysis, a discount factor of 7% as described in the NRC Regulatory Analysis Technical Evaluation Handbook was used to determine the present worth of averted risk over the 20-year license renewal period for ANO-1.

The PSA results used in this analysis are calculated using internal event results only. To account for the potential impact of external events on the results of these SAMA evaluations, since ANO-1 does not currently have an external events PSA model, the benefits of each SAMA were doubled for purposes of comparing with its cost.

G.2.4 Sensitivity Analyses

NUREG/BR-0184 recommends using a 7% real (i.e., inflation-adjusted) discount rate for value-impact analysis and notes that a 3% discount rate should be used for sensitivity analysis to indicate the sensitivity of the results to the choice of discount rate. This reduced discount rate takes into account the additional uncertainties (i.e., interest rate fluctuations) in predicting costs for activities that would take place several years in the future. Analyses presented in Section 4.13.4 of the ER used the 7% discount rate in calculating benefits of all the unscreened SAMAs. Entergy Operations also performed a sensitivity analysis by substituting the lower discount rate and recalculating the benefit of the candidate SAMAs.

Other sensitivities were performed; each of the sensitivities resulted in an additional benefit result for each of the SAMAs analyzed in the cost-benefit analysis. In addition to the discount rate sensitivity discussed above, the sensitivities performed include:

- Calculation of the benefit assuming the baseline discount rate and assuming external events contributed an amount equivalent to internal events to the CDF.
- Calculation of the benefit assuming averted onsite costs included the cost of replacement power and assuming the baseline discount rate.
- Calculation of the benefit assuming averted onsite costs included the cost of repair/refurbishment and assuming the baseline discount rate.
- Calculation of the benefit assuming a discount rate that is realistic for Entergy Operations (15%).

The benefits calculated for each of these sensitivities are presented in Table G.2-3

G.2.5 References

1. "Arkansas Nuclear One Unit 1 Probabilistic Risk Assessment Summary Report", April 1993, Entergy Operations.
2. Letter from Mr. M. O. Medford (TVA) to NRC Document Control Desk, dated September 1, 1992. "Watts Bar Nuclear Plant (WBN) Units 1 and 2 – Generic Letter (GL) 88-20 – Individual Plant Examination (IPE) for Severe Accident Vulnerabilities – Response – (TAC M74488)."
3. "Cost Estimate for Severe Accident Mitigation Design Alternatives. Limerick Generating Station for Philadelphia Electric Company," Bechtel Power Corporation, June 22, 1989.
4. NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants," Volume 1, Table 5.35, Listing of SAMDAs considered for the Limerick Generating Station, NRC, May 1996.
5. NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants," Volume 1, Table 5.36, Listing of SAMDAs considered for the Comanche Peak Steam Electric Station, NRC, May 1996.
6. Letter from Mr. W. J. Museler (TVA) to NRC Document Control Desk, dated June 5, 1993. "Watts Bar Nuclear Plant (WBN) Units 1 and 2 – Severe Accident Mitigation Design Alternatives (SAMDA) - (TAC Nos. M77222 and M77223)."
7. Letter from Mr. D. E. Nunn (TVA) to NRC Document Control Desk, dated October 7, 1994. "Watts Bar Nuclear Plant (WBN) Units 1 and 2 – Severe Accident Mitigation Design Alternatives (SAMDA) – Response to Request for Additional Information (RAI) - (TAC Nos. M77222 and M77223)."
8. Letter from N. J. Liparulo (Westinghouse Electric Corporation) to NRC Document Control Desk, dated December 15, 1992, "Submittal of Material Pertinent to the AP600 Design Certification Review."
9. Brookhaven National Laboratory, Department of Advanced Technology, Technical Report FIN W-6449, "NRC – IPE Workshop Summary/ Held in Austin Texas; April 7-9 1997," dated July 17, 1997/Appendix F – Industry Presentation Material, Contribution by Swedish Nuclear Power Inspectorate (SKI) and Safety Assessment Consulting (SAC): "Insights from PSAs for European Nuclear Power Plants," presented by Wolfgang Werner, SAC.
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11. NUREG 0498, "Final Environmental Statement related to the operation of Watts Bar Nuclear Plant, Units 1 and 2," Supplement No. 1, NRC, April 1995.
12. NUREG/CR-5567, "PWR Dry Containment Issue Characterization," NRC, August 1990.
13. NUREG-1560, "Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance," Volume 2, NRC, December 1997.

14. NUREG/CR-5630, “PWR Dry Containment Parametric Studies,” NRC, April 1991.
15. NUREG/CR-5575, “Quantitative Analysis of Potential Performance Improvements for the Dry PWR Containment,” NRC, August 1990.
16. CESSAR Design Certification, Appendix U, Section 19.15.5, Use of PRA in the Design Process, December 31, 1993.
17. NUREG 1462, “Final Safety Evaluation Report Related to the Certification of the System 80+ Design,” NRC, August 1994.
18. Forsberg, C. W., E. C., Beahm, and G. W. Parker, “Core-Melt Source Reduction System (COMSORS) to Terminate LWR Core-Melt Accidents,” Second International Conference on Nuclear Engineering (ICONE-2) San Francisco, California, March 21-24, 1993.
19. “Summary Report of Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities for Arkansas Nuclear One, Unit 1,” May 1996, Entergy Operations.
20. “Regulatory Analysis Technical Evaluation Handbook”, NUREG/BR-0184, January 1997.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
1	Cap downstream piping of normally closed ICW drain and vent valves	Reduces the frequency of loss of ICW initiating event, a large portion of which was derived from catastrophic failure of one of the many single isolation valves.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
2	Enhance Loss of ICW (or LOSW) procedure to facilitate stopping RCPs	Reduces potential for RCP failure due to loss of seal cooling and seal injection.	(1), (2), (10), (13)	B	ANO-1 has procedure 1203.031 (Reactor Coolant Pump and Motor Emergency) which provides procedural guidance for required actions following a loss of seal cooling. This procedure is deemed to be adequate to ensure that the RCPs will be stopped after loss of cooling.
3	Enhance Loss of ICW procedure to present desirability of cooling down RCS prior to seal LOCA	Potential reduction in the probability of RCP seal failure.	(2)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
4	Additional training on the Loss of ICW	Potential improvement in success rate of operator actions after a loss of ICW.	(2)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
5	Provide hardware connections to allow another ERCW (SW) to cool makeup pump seals	Reduce effect of loss of SW by providing a means to maintain the makeup pump seal injection after a loss of SW. Note, in Watts Bar, this capability was already there for one charging pump at one unit, and the potential enhancement identified was to make it possible for all of the charging pumps	(2), (6), (11), (13)	A	ANO-1 Make Up Pumps do not require SW for seal cooling. SW is only required for lube oil cooling on the Make Up Pump. Therefore, this item does not apply to ANO. See SAMA #7 for an evaluation of enhancing the lube oil cooling subsystem.
6	On loss of ERCW (SW), proceduralize shedding ICW loads to extend the ICW heatup time	Increase time before the loss of ICW (and RCP seal failure) in the loss of ERCW sequences.	(2)	A	Upon loss of cooling to ICW, other loads would take precedence over continued operation of the RCPs. The RCPs would be stopped so the need for cooling would be obviated. Seal injection would still be available, also.
7	Increase makeup pump lube oil capacity	Would lengthen time before makeup pump failure due to lube oil overheating in loss of SW sequences	(2)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
8	Eliminate RCP thermal barrier dependence on ICW, such that loss of ICW does not result directly in core damage.	Would prevent loss of RCP seal integrity after a loss of ICW. Watts Bar IPE said they could do this with ERCW connection to makeup pump seals.	(2), (13)	B	The suggestion was for the Watts Bar plant at which RCP thermal barrier cooling is dependent on CCW. At ANO-1 thermal barrier cooling is not dependent on ICW (the ANO-1 equivalent system to CCW) as the seal injection pumps can continue to supply seal cooling during a loss of ICW. Therefore the suggestion is considered to be already incorporated at ANO-1.
9	Provide additional SW pump	Providing another pump would decrease core damage frequency due to a loss of SW	(5)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
10	Create an independent RCP seal injection system, with dedicated diesel	Would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of ICW, SW or SBO.	(6), (11), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
11	Create an independent RCP seal injection system, without dedicated diesel	Would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of ICW, SW, but not SBO.	(11)	N	Not initially screened. Considered further in the final (cost-benefit) screening.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
12	Use existing hydro test pump for RCP seal injection	Independent seal injection source, without cost of a new system	(7)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
13	Replace ECCS pump motors with air cooled motors	Remove dependency on ICW	(10), (13)	B	The ECCS pump motors are already air cooled in the ANO-1 design. (lube-oil coolers require SW, however other plant change evaluations show that the cost of removing this dependency is much greater than the benefit achieved)
14	Install improved RCP seals	RCP seal O-rings constructed of improved materials would reduce chances of RCP seal LOCA	(11), (13)	A	Seals in ANO-1 are B-J 9000 series and are currently not expected to fail with cooling available. Improvements to the seals are therefore not needed.
15	Add a third ICW pump	Reduce chance of loss of ICW leading to RCP seal LOCA	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
16	Prevent makeup pump flow diversion from the relief valves	If relief valve opening causes a flow diversion large enough to prevent RCP seal injection, then modification can reduce frequency of loss of RCP seal cooling.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
17	Change procedures to isolate RCP seal return flow on loss of ICW, and guidance on loss of injection during seal LOCA.	Reduce CDF from loss of seal cooling.	(13)	B	ANO-1 has procedure 1203.031 (Reactor Coolant Pump and Motor Emergency) which provides procedural guidance for required actions following a loss of seal cooling.
18	Procedures to stagger HPI pump use after a loss of SW	Allow high pressure injection to be extended after a loss of SW	(1), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
19	Use firewater pumps as a backup seal injection and high pressure makeup	Reduce RCP seal LOCA frequency and SBO core damage frequency	(13)	A	Fire water does not have sufficient discharge pressure to be used for RCP seal injection. Current procedural direction is to stop RCPs upon loss of seal cooling. The use of fire water as a backup reactor vessel makeup source is applicable to BWR only since it is not borated water and is provided at low discharge pressure.
20	Procedural guidance for use of cross-tied ICW or SW pumps	Can reduce the frequency of the loss of either of these.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
21	Procedure & training enhancements in support system failure sequences	Potential improvement in success rate of operator actions after support system failures due to more procedural guidance on anticipating problems and coping.	(2), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
22	Improve ability to cool RHR heat exchangers	Reduced chance of loss of DHR by 1)Performing procedure and hardware modification to allow manual alignment of fire protection system to the ICW system, or 2)Installing an ICW header cross-tie	(12), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
23	Stage backup fans in Switchgear rooms	Provides alternate ventilation in the event of a loss of switchgear ventilation.	(13)	A	ANO-1 PSA does not include dependency on HVAC

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
24	Provide redundant train of ventilation to 480V board room.	Would improve reliability of 480V HVAC. At Watts Bar, only one train of HVAC cools the 480V board room that contains the unit vital inverters, and recovery actions are heavily relied on. Watts Bar IPE said their corrective action program is dealing with this.	(2), (13)	A	ANO-1 PSA does not include dependency on HVAC
25	Procedures for temporary HVAC	Provides for improved credit to be taken for loss of HVAC sequences	(11), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
26	Add a switchgear room high temp alarm	Improve diagnosis of a loss of switchgear HVAC	(13)	A	ANO-1 PSA does not include dependency on HVAC. In addition, local fan units are actuated based upon temperature limits as per Procedure 1104.027.
27	Create ability to switch fan power supply to DC in SBO	(Was created for a BWR RCIC room, Fitzpatrick; possible for turbine AFW if has its own fan) Allow continued operation in SBO	(13)	A	ANO-1 PSA does not include dependency on HVAC
28	Delay containment spray actuation after large LOCA	When ice remains in the ice condenser at such plants, containment sprays have little impact on containment performance, yet rapidly drain down the BWST. This improvement would lengthen time of BWST availability.	(2), (6)	A	Not Applicable to ANO-1. Applicable to ice condenser plant.
29	Install containment spray throttle valves	Can extend the time over which water remains in the BWST, when full containment spray flow is not needed.	(11), (12), (13)	A	Not Applicable - ANO-1 already has the capability to throttle RB spray. Procedure 1202.10 requires the operator to throttle spray flow in order to balance the flow and lengthen the time that water is available in the BWST for certain events.
30	Install an independent method of suppression pool cooling	Would decrease frequency of loss of containment heat removal	(3), (4)	A	This is applicable only to BWR.
31	Develop an enhanced drywell spray system	Would provide a redundant source of water to the containment to control containment pressure, when used in conjunction with containment heat removal	(3), (4), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
32	Provide a dedicated existing drywell spray system	Identical to the previous concept, except that one of the existing spray loops would be used instead of developing a new spray system.	(3), (4) (similar in (5), (6), (11))	N	Not initially screened. Considered further in the final (cost-benefit) screening.
33	Install a containment vent large enough to remove ATWS decay heat	Assuming injection is available, would provide alternative decay heat removal in an ATWS	(3), (4)	A	Not applicable to PWRs
34	Install a filtered containment vent to remove decay heat	Assuming injection is available (non-ATWS sequences), would provide alternate decay heat removal with the released fission products being scrubbed.	(3), (4), (5), (6), (8), (11), (12), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
35	Install an unfiltered hardened containment vent	Provides an alternate decay heat removal method (non-ATWS), which is not filtered	(3), (4), (9), (14)	N	Not initially screened. Considered further in the final (cost-benefit) screening.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
36	Create/enhance hydrogen igniters with independent power supply.	Use either a new, independent power supply, a non-safety grade portable generator, existing station batteries, or existing AC/DC independent power supplies such as the security system diesel. Would reduce hydrogen detonation at lower cost.	(3), (5), (6), (7), (9), (12), (13), (14), (15), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
37	Create a passive hydrogen ignition system	Reduce hydrogen detonation potential without requiring electric power	(7), (11), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
38	Create a giant concrete crucible with heat removal potential under the basemat to contain molten debris	A molten core escaping from the vessel would be contained within the crucible. The water cooling mechanism would cool the molten core, preventing a melt-through.	(3), (4), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
39	Create a water cooled rubble bed on the pedestal	This rubble bed would contain a molten core dropping onto the pedestal, and would allow the debris to be cooled.	(3), (4), (8), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
40	Provide modification for flooding of the drywell head	Would help mitigate accidents that result in leakage through the drywell head seal	(4), (9)	A	This is applicable only to BWR.
41	Enhance fire protection system and/or standby gas treatment system hardware and procedures	Improve fission product scrubbing in severe accidents	(4)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
42	Create a reactor cavity flooding system	Would enhance debris coolability, reduce core concrete interaction and provide fission product scrubbing	(5), (6), (9), (11), (12), (13), (15), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
43.1	Creating other options for reactor cavity flooding (Part a)	(a)Use water from dead-ended volumes, the condensed blowdown of the RCS, or secondary system by drilling pathways in the reactor vessel support structure to allow drainage from the steam generator compartments, refueling canal, sumps, etc., to the reactor cavity. Also (for ice condensers), allow drainage of water from melted ice into the reactor cavity.	(7), (9), (13)	A	Not Applicable to ANO-1. Applicable to ice condenser plant.
43.2	Creating other options for reactor cavity flooding (Part b)	(b)Flood cavity via systems such as diesel driven fire pumps	(7), (9), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
44	Enhance air return fans (ice condenser containment)	Provide an independent power supply for the air return fans, reducing containment failure in SBO sequences	(6), (11)	A	Not Applicable to ANO-1. However, credit for the existing black diesel as an additional power supply is taken.
45	Provide a core debris control system	(Intended for ice-condenser plants): Would prevent the direct core debris attack of the primary containment steel shell by erecting a barrier between the seal table and containment shell.	(6), (11)	N	Not initially screened. Considered further in the final (cost-benefit) screening.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
46	Create a core melt source reduction system (COMSORS)	Place enough glass underneath the reactor vessel such that a molten core falling on the glass would melt and combine with the material. Subsequent spreading and heat removal from the vitrified compound would be facilitated, and concrete attack would not occur (such benefits are theorized in the reference).	(18)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
47	Provide containment inerting capability	Would prevent combustion of hydrogen and carbon monoxide gases	(6), (9), (11), (14)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
48	Use fire water spray pump for containment spray	Redundant containment spray method without high cost	(7), (9), (10), (12)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
49	Install a passive containment spray system	Containment spray benefits at a very high reliability, and without support systems	(8)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
50	Secondary containment filtered ventilation	For plants with a secondary containment, would filter fission products released from the primary containment	(8)	A	Not Applicable to ANO-1. No secondary containment building.
51	Increase containment design pressure	Reduce chance of containment overpressure	(8)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
52	Increase the depth of the concrete basemat, or use an alternative concrete material to ensure melt through does not occur	Prevent basemat melt through	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
53	Provide a reactor vessel exterior cooling system.	Potential to cool a molten core before it causes vessel failure, if the lower head can be submerged in water.	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
54	Create another building, maintained at a vacuum to be connected to containment	In an accident, connecting the new building to containment would depressurize containment and reduce any fission product release.	(17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
55	Add ribbing to the containment shell	Would reduce the chance of buckling of containment under reverse pressure loading.	(17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
56	Reactor Building Liner Protective Barrier	A protective barrier inside the incore instrument tunnel or along the reactor building liner just beyond the tunnel could prevent certain types of containment failure, which could result in a notable reduction in the large release frequency.	(1)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
57	Train operations crew for response to inadvertent actuation signals	Improves chances of a successful response to the loss of two 120V AC buses, which causes inadvertent signals.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
58	Proceduralize alignment of spare diesel to shutdown board after LOP and failure of the diesel normally supplying it	Reduced SBO frequency.	(2)	B	Such procedures have already been implemented.
59	Provide an additional diesel generator	Would increase on-site emergency AC power reliability and availability (decrease SBO) The ANO1 IPE reported that ANO committed to install an AAC power source capable of supplying the LOOP loads of any one the four safety buses. This source would be available within 10 minutes after determination of SBO conditions.	(1), (5), (6), (10), (13) (16), (17)	B	ANO-1 has already installed a diverse DG capable of powering either Class 1E bus.
60	Provide additional DC battery capability	Would ensure longer battery capability during a SBO, reducing frequency of long term SBO sequences.	(5), (6), (13), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
61	Use fuel cells instead of lead-acid batteries	Extend DC power availability in a SBO	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
62	Procedure to cross tie HPCS diesel	(BWR 5/6)	(10)	A	Not Applicable to ANO-1. Applicable to BWR 5/6.
63	Improved bus cross tie ability	Improved AC power reliability	(10), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
64	Alternate battery charging capability	Improved DC power reliability. Either cross tie of AC buses, or a portable diesel-driven battery charger.	(10), (11), (12), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
65	Increase/improve DC bus load shedding	Improved battery life in station blackout	(10), (11), (12), (13)	B	An analysis was performed in support of the ANO-1 PSA update that credited the black batteries for load shedding of the vital batteries. This analysis provided the basis for extending the vital battery life from 2 to 5 hours. This improvement is considered to be already implemented at ANO-1.
66	Replace batteries	Improved reliability	(10)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
67	Create AC power cross tie capability across units at a multi-unit site	Improved AC power reliability	(11), (12), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.

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SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
68	Create a cross-unit tie for diesel fuel oil	For multi-unit sites, adds diesel fuel oil redundancy.	(13)	B	The combination of day tank and fuel oil storage tank for each diesel provides for a 3.5 day fuel oil supply. Makeup to the fuel oil storage tanks is provided from the bulk diesel fuel oil storage tank through a filter. This tank has a capacity of 185,000 gallons. The combination of all diesel fuel oil storage provides for greater than 14 day supply. FSAR section 8.3.1.1.7.2 discusses alternatives even under conditions of extended flooding and limited site access. additionally ANO-1 already has the capability to crosstie the fuel pumps from ANO-2 to ANO-1, and this has been considered as a recovery in the ANO-1 PRA.
69	Develop procedures to repair or change out failed 4KV breakers	Offers a recovery path from a failure of breakers that perform transfer of 4.16 kV non-emergency buses from unit station service transformers to system station service transformers, leading to loss of emergency AC power (i.e., in conjunction with failures of the diesel generators).	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
70	Emphasize steps in recovery of offsite power after a SBO.	Reduced human error probability of offsite power recovery.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
71	Develop a severe weather conditions procedure	For plants that do not already have one, reduces the likelihood of external events CDF.	(13)	B	Such a procedure currently exists and it is being revised to further enhance guidance provided.
72	Procedures for replenishing diesel fuel oil	Allow long-term diesel operation	(13)	B	The combination of day tank and fuel oil storage tank for each diesel provides for a 3.5 day fuel oil supply. Makeup to the fuel oil storage tanks is provided from the bulk diesel fuel oil storage tank through a filter. This tank has a capacity of 185,000 gallons. The combination of all diesel fuel oil storage provides for greater than 14 day supply. FSAR section 8.3.1.1.7.2 discusses alternatives even under conditions of extended flooding and limited site access. The intent of this improvement is considered to be met.
73	Install gas turbine generators	Improve on-site AC power reliability	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
74	Install tornado protection on gas turbine generator	If the unit has a gas turbine, the tornado-induced SBO frequency would be reduced.	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
75	Create a river water backup for diesel cooling.	Provides redundant source of diesel cooling.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
76	Use firewater as a backup for diesel cooling	Redundancy in diesel support systems	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
77	Provide a connection to alternate offsite power source	Increase offsite power redundancy	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
78	Implement underground offsite power lines	Could improve offsite power reliability, particularly during severe weather.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.

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SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
79	Replace anchor bolts on diesel generator oil cooler	Millstone 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.	(13)	B	Since this is not on seismic issues list, a similar condition was not found at ANO-1. Additionally, the oil coolers for ANO-1 DGs are part of the DG skid and as such are considered to be seismically adequate for ANO-1. The intent of this improvement is considered to be met.
80	Proceduralize use of pressurizer vent valves during SGTR sequences	CCNP procedures direct the use of pressurizer sprays to reduce RCS pressure after a SGTR. Use of the vent valves provides a backup method.	(13)	A	Not Applicable - ANO-1 has ERVs and auxiliary spray that could be utilized for depressurization but does not have remotely operated pressurizer vents. (See also #151.)
81	Install a redundant spray system to depressurize the primary system during a SGTR.	Enhanced depressurization ability during SGTR.	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
82	Improved SGTR coping abilities	Improved instrumentation to detect SGTR, or additional systems to scrub fission product releases.	(7), (9), (10), (13), (14), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
83	Adding other SGTR coping features. Options: A) SG shell-side HR System. B) System to return SG RV disch to Containment. C) Increase psr capacity of SG shell side	(a)A highly reliable (closed loop) steam generator shell-side heat removal system that relies on natural circulation and stored water sources, (b)a system which returns the discharge from the steam generator relief valve back to the primary containment, (c)an increased pressure capability on the steam generator shell side with corresponding increase in the safety valve setpoints.	(7), (8), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
84	Increase secondary side pressure capacity such that a SGTR would not cause the relief valves to lift	SGTR sequences would not have a direct release pathway	(8), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
85	Replace steam generators with new design	Lower frequency of SGTR	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
86	Revise EOPs to direct that a faulted steam generator be isolated.	For plants whose EOPs don't already direct this, would reduce consequences of a SGTR	(13)	B	ANO-1 procedures already direct isolation of a faulted SG.
87	Direct steam generator flooding after a SGTR, prior to core damage.	Would provide for improved scrubbing of SGTR releases.	(14), (15)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
88	Implement a maintenance practice that inspects 100% of the tubes in a steam generator	Reduce chances of tube rupture	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
89	Locate RHR inside of containment	Would prevent ISLOCA out the RHR pathway	(8)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
90	Provide self-actuating containment isolation valves	For plants that don't have this, it would reduce the frequency of isolation failure	(8)	N	Not initially screened. Considered further in the final (cost-benefit) screening.

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SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
91	Install additional instrumentation for ISLOCA sequences	Pressure or leak monitoring instruments installed between the first two pressure isolation valves on low-pressure injection lines, RHR suction lines, and high pressure injection lines would decrease ISLOCA frequency.	(5), (6), (11), (13)	B	ANO-1 already has pressure transmitters between the first two pressure isolation valves for LPI and the RHR suction valves which are monitored regularly. (The HPI lines are designed for RCS pressure and do not present a possible ISLOCA scenario).
92	Increase frequency of valve leak testing	Decrease ISLOCA frequency	(12)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
93	Improve operator training on ISLOCA coping	Decrease ISLOCA effects	(12), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
94	Install relief valves in the ICW system	Would relieve pressure buildup from an RCP thermal barrier tube rupture, preventing an ISLOCA	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
95	Provide leak testing of valves in ISLOCA paths	At Kewaunee, four MOVs isolating RHR from the RCS were not leak tested. Will help reduce ISLOCA frequency	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
96	Revise EOPs to improve ISLOCA identification	Salem had a scenario in which an RHR ISLOCA could direct initial leakage back to the PRT, giving indication that the LOCA was inside containment. Procedure enhancement would ensure LOCA outside containment would be observed.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
97	Ensure all ISLOCA releases are scrubbed	Would scrub ISLOCA releases. One suggestion was to plug drains in the break area so the break point would cover with water.	(14), (15)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
98	Add redundant and diverse limit switch to each containment isolation valve.	Enhanced isolation valve position indication, which would reduce frequency of containment isolation failure and ISLOCAs.	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
99	Keep LPI/DHR and RB Spray Pump drains closed.	LPI pumps will not be affected by an ISLOCA which discharges into the auxiliary building.	(1)	B	This has been previously implemented. The LPI\DHR and RB Spray pump room drain isolation valves were changed from normally open to normally closed.
100	Valve Position Verification	The ANO1 IPE indicates one valve in the reactor building air monitoring leak detection system that can present a challenge to reactor building integrity during an SBO. On a degraded power or SBO condition, CV-7453 (an MOV) may not close; in this condition it is important to verify the other valve (CV-7454) closed to ensure reactor building integrity.	(1)	B	IPE improvement implemented per M.E. Byram letter dated 20Dec1994, subj. "ANO-1 PRA Potential Plant Improvements".
101	Conserve BWST inventory post accident	Modify procedures to conserve the Borated Water Storage Tank during SGTRs. Alternatively BWST refill could be utilized to provide long term injection capability (see item #83).	(1)	B	This item has been implemented per owner's group SAMG guidelines. The intent of this improvement is considered to be met.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
102	Removal and Flanging of the Hydrogen Purge Valves	The hydrogen purge system is not used (at the time of the IPE); the outboard RB isolation valves (CV-7443, CV-7445, CV-7447, CV-7449) are locked closed with their breakers removed. The inboard valves are left open following an event to allow for hydrogen monitoring.	(1)	B	IPE improvement implemented per M.E. Byram letter dated 20Dec1994, subj. "ANO-1 PRA Potential Plant Improvements".
103	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment	For a plant where internal flooding from turbine building to safeguards areas is a concern, this modification can prevent flood propagation.	(13)	A	The ANO-1 internal flood analysis report was reviewed and no similar concerns were identified.
104	Improve inspection of rubber expansion joints on main condenser	For a plant where internal flooding due to failure of circulating water expansion joint is a concern, this can help reduce the frequency.	(13)	A	The ANO-1 internal flood analysis report was reviewed and no similar concerns were identified.
105	Internal flood prevention and mitigation enhancements	1)Use of submersible MOV operators. 2)Back flow prevention in drain lines.	(13)	A	The ANO-1 internal flood analysis report was reviewed. All rooms affected by flood propagation through floor drains were determined to have a core damage frequency due to the flooding concerns that was lower than the screening frequency.
106	Internal flooding improvements at Fort Calhoun	Prevention or mitigation of 1)A rupture in the RCP seal cooler of the ICW system, 2)An ISLOCA in a shutdown cooling line, 3)An AFW flood involving the need to possibly remove a watertight door. For a plant where any of these apply, would reduce flooding risk.	(13)	A	The ANO-1 internal flood analysis report was reviewed and these scenarios are either not applicable to ANO-1 or are insignificant contributors to CDF.
107	Install digital feedwater upgrade	Reduces chance of loss of MFW following a plant trip.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
108	Perform surveillances on manual valves used for backup AFW pump suction	Improves success probability for providing alternate water supply to AFW pumps.	(13)	B	A backup CST already exists (T41) (also crosstie capability to other unit) as does procedural guidance for its use following loss of the normal CST. This tank is not credited in the current PSA model. Additionally, both loops of service water serve as an assured backup water source. The Service water backup valves are surveilled. No significant gain would result from testing these valves. No action is required.
109	Install manual isolation valves around AFW turbine driven steam admission valves	Reduces the dual turbine driven pump maintenance unavailability.	(13)	A	ANO-1 does not have a dual TD pump configuration.
110	Install accumulators for turbine driven AFW pump flow control valves	Provide control air accumulators for the turbine driven AFW flow control valves, the motor driven AFW pressure control valves, and S/G PORVs. This would eliminate the need for local manual action to align nitrogen bottles for control air during a LOP.	(11)	A	ANO-1 TDP does not have AOVs for control valves.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
111	Install a new CST (AFWST)	Either replace old tank with a larger one, or install a backup tank	(13), (16), (17)	B	A backup CST already exists (T41) (also crosstie capability to other unit) as does procedural guidance for its use following loss of the normal CST. This tank is not credited in the current PSA model. Additionally, both loops of service water serve as an assured backup water source. The current CST is analyzed to have a 24 hour capacity. No action is required.
112	Cooling of steam driven AFW pump in a SBO	1)Use firewater to cool pump, or 2)Make the pump self-cooled. Would improve success chances in a SBO	(13)	A	Not Applicable - Both the MD and TD EFW pumps are self cooled.
113	Proceduralize local manual operation of AFW when control power is lost	Lengthen AFW availability in SBO. Also provides a success path should AFW control power be lost in non-SBO sequences.	(13)	B	ANO-1 already has a procedure which addresses the ability to take local manual control of the steam flow to the turbine driven pump if automatic control is lost due to a loss of power.
114	Provide portable generators to be hooked in to the turbine driven AFW, after battery depletion	Extend AFW availability in a SBO (assuming the turbine-driven AFW requires DC power)	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
115	Add a motor train of AFW to the steam trains.	For PWRs that do not have any motor trains of AFW, this can increase reliability in non-SBO sequences.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
116	Create ability for emergency connections of existing or alternate water sources to feedwater/condensate	Would be a backup water supply for the feedwater/condensate systems.	(12)	A	A backup CST already exists (T41) (also crosstie capability to other unit) as does procedural guidance for its use following loss of the normal CST. This tank is not credited in the current PSA model. Additionally, both loops of service water serve as an alternate source.
117	Use firewater as a backup for steam generator inventory	Would create a backup to main and auxiliary feedwater for steam generator water supply	(13)	A	A backup CST already exists (T41) (also crosstie capability to other unit) as does procedural guidance for its use following loss of the normal CST. This tank is not credited in the current PSA model. Additionally, both loops of service water serve as an alternate source.
118	Procure a portable diesel pump for isolation condenser makeup	Backup to the city water supply and diesel fire water pump in providing isolation condenser makeup	(13)	A	Not Applicable to ANO-1. Applicable to ice condenser plant.
119	Install an independent diesel for the condensate storage tank makeup pumps	Would allow continued inventory in CST during a SBO	(13)	A	A backup CST already exists (T41) (also crosstie capability to other unit) as does procedural guidance for its use following loss of the normal CST. This tank is not credited in the current PSA model. Additionally, both loops of service water serve as an assured backup water source. The current CST is analyzed to have a 24 hour capacity. No action is required.
120	Change failure position of condenser makeup valve.	If the condenser makeup valve fails open on loss of air or power, this can prevent CST flow diversion to condenser. Allows greater inventory for the EFW pumps.	(13)	A	Not Applicable - ANO-1 does not have a pneumatic valve in the position referred to in this SAMA. ANO-1 has a locked closed manual 3-way valve in this location, which is locked closed to the condenser.
121	Create passive secondary side coolers	Provide a passive heat removal loop with a condenser and heat sink. Would reduce CDF from the loss of feedwater.	(17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
122	EFW Pump Common Discharge Valve	Removal of the internals of manual valve FW-1016 (common discharge valve from the EFW pumps to the Circulating Water Flume) would reduce the likelihood of loss of both EFW trains due to valve closure. The function of this valve (isolation of the EFW pumps for maintenance) is redundant with individual pump discharge isolation valves.	(1)	B	This modification was implemented per plant change PC 95-7081
123	Provide capability for diesel driven, low pressure vessel makeup	Extra water source in sequences in which the reactor is depressurized and all other injection is unavailable (e.g., firewater)	(4), (5), (13)	A	The proposed modification applies primarily to BWRs (for ANO-1 a diverse high pressure injection provides more benefit and is analyzed in #84). At ANO-1 only hardware related high pressure recirculation core damage events could be potentially mitigated (insufficient time to manually align a backup system on failure of injection for medium and large LOCAs). The estimated benefit is approximately 8% of MAB ($145.4K) or $11.6K. Since the cost of the proposed modification is judged to be greater than the MAB ($145.4K), the suggestion was screened out from further consideration.
124	Provide an additional high pressure injection pump with independent diesel	Reduce frequency of core melt from small LOCA sequences, and from SBO sequences.	(6), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
125	Install independent AC high pressure injection system	Would allow make up and feed and bleed capabilities during a SBO	(11)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
126	Create the ability to manually align ECCS recirculation	Provides a backup should automatic or remote operation fail	(1), (12)	B	Since the proposed modification facilitates local operation of recirculation valves when remote operation fails, the risk reduction benefit of the proposed change was estimated by effectively reducing the recirculation MOV fail to transfer probability to zero (conservatively assuming that all remote failures can be recovered locally for small LOCA events). CDF was estimated to decrease by 1.6E-7 or by 1.6%. The benefit of the proposed change is estimated as <$2.4k (0.016*$145.4K). Since the cost of the proposed modification is judged to be much greater than the assessed benefit, the modification was screened out from further consideration. The capability for local operation exists, since recovery by local operation is considered in the PSA.
127	Implement a BWST makeup procedure	Decrease core damage frequency from ISLOCA scenarios, some smaller break LOCA scenarios, and SGTR	(12), (13)	B	ANO-1 already has guidance for injection from other water sources in the event of inadequate BWST level. The normal procedure is 1104.003 -- CHEMICAL ADDITION, Section 9.0 step 9.3 directs the use of Attachment L (Boric Acid and Condensate Addition to BWST (T-3)). Other means are: Procedure 1104.020 -- CLEAN WASTE SYSTEM OPERATION, Section 34.0 "BWST Fill From Clean Waste Receiver Tank (T-12A, B, C, D)"; Procedure 1104.006 -- SPENT FUEL COOLING SYSTEM, Section 12.0 "Spent Fuel Pool Level Reduction", Step 12.2 using P-40A or B aligned to the BWST and Step 12.3 using P-66 aligned to the BWST.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
128	Stop low pressure injection pumps earlier in medium or large LOCAs	Would give more time to perform recirculation swapover.	(13)	A	Not Applicable. ANO-1 procedures do not require that low pressure injection pumps be secured during medium or large LOCAs.
129	Emphasize timely recirc swapover in operator training	Reduce human error probability of recirculation failure	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
130	Upgrade CVCS to mitigate small LOCAs	For a plant like the AP600 where CVCS can't mitigate small LOCA, an upgrade would decrease CDF from small LOCA	(8)	A	Not applicable to ANO-1.
131	Install an active high pressure SI system	For a plant like the AP600, where an active high pressure injection system does not exist, would add redundancy in high pressure injection.	(8)	A	Not applicable to ANO-1.
132	Change "in-containment" BWST suction from 4 check valves to 2 check and 2 air operated valves	Remove common mode failure of all four injection paths	(8)	A	ANO-1 has a single suction line (that contains a locked open manual valve) from the BWST that results in a single failure vulnerability for the ECCS pumps. Review of the ANO-1 core damage results indicates that CDF could be reduced by 2.7E-8 (by 0.26%) if this single failure vulnerability was eliminated. Since the benefit of the change (approximately $400 or 0.26% of the MAB of $145.4K) is clearly much less than the associated cost this suggestion was screened out from further consideration.
133	Replace two of the four safety injection pumps with diesel pumps	Intended for System 80+, which has four trains of SI. This would reduce common cause failure probability.	(16), (17)	A	The maximum benefit for reducing core damage to zero is $145.4K. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. ANO-1 has 2 LPSI pumps and 3 HPSI pumps but the conclusion remains the same.
134	Align LPCI or core spray to CST on loss of suppression pool cooling	Low pressure ECCS can be maintained in loss of suppression pool cooling scenarios	(10), (13)	A	Not Applicable to ANO-1. Applicable to BWR.
135	Raise HPCI/RCIC backpressure trip setpoints	Ensures HPCI/RCIC availability when high suppression pool temperatures exist.	(13)	A	Not Applicable to ANO-1. Applicable to BWR.
136	Improve the reliability of the ADS	Reduce frequency high pressure core damage sequences	(4)	A	Not Applicable to ANO-1. Applicable to BWR.
137	Disallow automatic vessel depressurization in non-ATWS scenarios	Improve operator control of plant.	(13)	A	Not Applicable to ANO-1. Applicable to BWR.
138	Create automatic swapover to recirculation on BWST depletion	Would remove human error contribution from recirculation failure.	(5), (6), (11)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
139	Modify EOPs for ability to align diesel power to more air compressors.	For plants which do not have diesel power to all normal and backup air compressors, this change allows increased reliability of instrument air after a LOP.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
140	Replace old air compressors with more reliable ones.	Improve reliability and increase availability of instrument air compressors.	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
141	Install Nitrogen bottles as backup gas supply for SRVs	Extend operation of Safety Relief Valves during SBO and loss of air events (BWRs)	(13)	A	Not Applicable to ANO-1. Applicable to BWR.
142	Install MG set trip breakers in control room	Provides trip breakers for the motor generator sets in the control room. Currently, at Watts Bar, an ATWS would require an immediate action outside the control room to trip the MG sets. Would reduce ATWS CDF	(11)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
143	Add capability to remove power from the bus powering the control rods	Decrease time to insert control rods when if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	(13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
144	Create cross-connect ability for standby liquid control (SLC) trains	Improved reliability for boron injection during ATWS	(13)	A	Not Applicable to ANO-1. Applicable to BWR.
145	Create an alternate boron injection capability (backup to SLC)	Improved reliability for boron injection during ATWS	(13)	A	Not Applicable to ANO-1. Applicable to BWR.
146	Remove or allow override of LPCI injection during ATWS	On failure of HPCI and condensate, the Susquehanna units direct reactor depressurization followed by 5 minutes of automatic LPCI injection. Would allow control of LPCI immediately.	(13)	A	Not Applicable to ANO-1. Applicable to BWR.
147	Add a system of relief valves that prevents any equipment damage from a pressure spike during an ATWS	Would improve equipment availability after an ATWS.	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
148	Create a boron injection system to back up the mechanical control rods.	Provides a redundant means to shut down the reactor.	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
149	Provide an additional I&C system (e.g., AMSAC).	Improve I&C redundancy and reduce ATWS frequency.	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
150	Provide capability for remote operation of secondary side PORVs in SBO	Manual operation of these valves is required in a SBO scenario. High area temperatures may be encountered in this case (no ventilation to main steam areas), and remote operation could improve success probability.	(2)	B	ANO-1 already has the ability and procedural guidance to take manual control of these valves by using a chain pulley from the elevation below.
151	Create/enhance reactor coolant system depressurization ability	Either with a new depressurization system, or with existing PORVs, head vents and secondary side valve, RCS depressurization would allow low pressure ECCS injection. Even if core damage occurs, low RCS pressure alleviates some concerns about high pressure melt injection.	(5), (6), (9), (11), (12), (13), (14), (15), (16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
152	Make procedural changes only for the RCS depressurization option	Reduce RCS pressure without cost of a new system	(7), (9), (13)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
153	Defeat 100% load rejection capability	Eliminates the possibility of a stuck open PORV after a LOP, since PORV opening wouldn't be needed	(13)	A	Not applicable to ANO-1 as ANO-1 does not have 100% load rejection capability.
154	Change CRD flow control valve failure position	Change failure position to the 'fail-safest' position	(13)	A	Not Applicable to ANO-1. Applicable to BWR.
155	Add secondary side guard pipes up to the MSIVs.	Would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. Would also guard against or prevent consequential multiple SGTR following a main steam line break event.	(16), (17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
156	Digital large break LOCA protection	Upgrade plant instrumentation and logic to improve the capability to identify symptoms/precursors of a large break LOCA (a leak before break).	(17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
157	Increase seismic capacity of the plant to a HCLPF of twice the SSE	Reduced seismic CDF	(17)	N	Not initially screened. Considered further in the final (cost-benefit) screening.
158	Bolt MCC B-61 and B-62 together.	MCC B-61 and B-62 are next to each other, contain essential relays and are not bolted together.	(19)	B	The proposed modification has already been incorporated.
159	Confirm adequate anchorage for MCC B-21	Confirmation of adequate anchorage of MCC B-21 must be confirmed.	(19)	B	The proposed modification has already been incorporated.
160	File cabinets next to control cabinets C-47, C-54, C-28 must be secured to prevent them from toppling during an earthquake.	Control cabinets C-47, C-54, C-28 had unsecured file cabinets adjacent to them that could topple in an earthquake.	(19)	B	The proposed modification has already been incorporated.
161	EFIC Signal Conditioning Cabinets C-540A and C-540B must be bolted together.	EFIC Signal Conditioning Cabinets C-540A and C-540B are next to each other, contain essential relays and are not bolted together.	(19)	B	The proposed modification has already been incorporated.
162	Compressed oxygen bottle rack next to Control Cabinet C-27 must be secured.	Compressed oxygen bottle rack next to Control Cabinet C-27 is unsecured.	(19)	B	The proposed modification has already been incorporated.
163	Propane Tank T-70 must be anchored.	Propane Tank T-70, located approximately 15 feet from Condensate Storage Tank T-41, is not anchored.	(19)	B	The proposed modification has already been incorporated.

Table G.2-1 INITIAL LIST OF CANDIDATE IMPROVEMENTS FOR THE ANO-1 SAMAs ANALYSIS

SAMA Number	Potential Improvement	Discussion	Source/ Reference	Screening Criterion	Evaluation
164	The angle frame around the cover plate for valves CV-2233, CV-2234, CV-2214 must be widened to accommodate more movement.	The angle frame around the cover plate for valves CV-2233, CV-2234, CV-2214 could interact with the valves during an earthquake.	(19)	B	The proposed modification has already been incorporated.
165	Adequate clearance for MOV CV-3851 must be verified	The valve hand wheel for MOV CV-3851 is within ¼" of a support and could be damaged in an earthquake.	(19)	B	The proposed modification has already been incorporated.
166	Additional flexibility in the power cable for CV-3850 must be provided.	The power cable for CV-3850 is taut between the valve and a support and could potentially pull out during an earthquake.	(19)	B	The proposed modification has already been incorporated.
167	Further investigate the calculated value for HCLPF (<0.3g) for the Emergency Diesel Fuel Tanks (T-57A and T-57B)	The Emergency Diesel Fuel Tanks (T-57A and T-57B) have a calculated HCLPF value below 0.3g.	(19)	B	The proposed modification has already been incorporated.
168	Add scuppers to the parapet walls of the ANO1 roof structures to limit the amount of water that can build up.	Local, intense precipitation or Probable Maximum Precipitation (PMP) may create excessive roof loading due to ponding.	(19)	B	The proposed modification has already been incorporated.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
1	Cap downstream piping of normally closed ICW drain and vent valves	Reduces the frequency of loss of ICW initiating event, a large portion of which was derived from catastrophic failure of one of the many single isolation valves.	3.2%	0.6%	<$4k	>2 x Benefit	Screen out	Loss of ICW is included as part of the Loss of Power Conversion System initiating event. Analysis case ICW1 determined the benefit of eliminating all causes of this initiating event to be <$4K. The costs associated with the needed procedure changes and/or plant modifications required to implement this alternative are greater than the benefit. Not cost-beneficial; cost is expected to exceed twice the benefit.
3	Enhance Loss of ICW procedure to present desirability of cooling down RCS prior to seal LOCA	Potential reduction in the probability of RCP seal failure.	3.2%	0.6%	<$4k	>2 x Benefit	Screen out	Based on the low risk reduction worth of the ANO-1 ICW system (see #1 and #15, case ICW1), the maximum benefit of a procedure change which eliminates or mitigates all loss of ICW events is less than $4k (ANO-1 is not as susceptible to loss of ICW as many plants as the ECCS pumps are cooled directly by service water and therefore: (a) seal cooling can continue unabated following a loss of ICW event via continued seal injection; (b) a seal LOCA initiated by loss of ICW can be mitigated). Considering that: (a) the estimate above was calculated in a very conservative manner [assumed to eliminate all loss of PCS initiating events (%T2)] (b) the ability to prevent/ mitigate ICW events from additional training/ procedure changes is limited, it is clear that the cost of the suggestion is not justified by the associated risk reduction. Not cost-beneficial; cost is expected to exceed twice the benefit.
4	Additional training on the Loss of ICW	Potential improvement in success rate of operator actions after a loss of ICW.	3.2%	0.6%	<$4k	>2 x Benefit	Screen out	Based on the low risk reduction worth of the ANO-1 ICW system (see #1 and #15, case ICW1), the maximum benefit of a procedure change which eliminates or mitigates all loss of ICW events is less than $4K (ANO-1 is not as susceptible to loss of ICW as many plants as the ECCS pumps are cooled directly by service water and therefore: (a) seal cooling can continue unabated following a loss of ICW event via continued seal injection; (b) a seal LOCA initiated by loss of ICW can be mitigated). Considering that: (a) the estimate above was calculated in a very conservative manner [assumed to eliminate all loss of PCS initiating events (%T2)] (b) the ability to prevent/ mitigate ICW events from additional training/ procedure changes is limited, it is clear that the cost of the suggestion is not justified by the associated risk reduction. Not cost-beneficial; cost is expected to exceed twice the benefit.
7	Increase makeup pump lube oil capacity	Would lengthen time before makeup pump failure due to lube oil overheating in loss of SW sequences	22.7%	21.5%	<$33k	>2 x Benefit	Screen out	Analysis case LOSWTOMU determined the benefit from eliminating all dependence of MU pumps on SW to be <$33k. In order to implement this alternative, hardware changes would be necessary to increase the oil capacity, add oil-air heat exchangers, increase room cooling capacity. Procedures would need to be modified. The combined cost of these changes will be greater than the benefit obtained. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
9	Provide additional SW pump	Providing another pump would decrease core damage frequency due to a loss of SW	27.0%	Note 1	<$39.3k	>2 x Benefit	Screen out	The maximum benefit from a plant change that reduces the CDF due to SW failures to zero is estimated as approximately $39.3k (27% of MAB, as approximately 27% of CDF can be attributed to SW failures). The actual benefit is estimated as less than $39.3k, since loss of SW scenarios cannot be entirely eliminated by adding an additional pump. The cost of adding an additional service water pump is judged to be greater than this amount, even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
10	Create an independent RCP seal injection system, with dedicated diesel	Would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of ICW, SW or SBO.	23.6%	21.1%	<$33.4k	>2 x Benefit	Screen out	Analysis case RCPLOCA determined the benefit from eliminating all RCP seal LOCAs to be <$33.4k. The modifications required to implement this alternative are judged to exceed this amount without having a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
11	Create an independent RCP seal injection system, without dedicated diesel	Would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of ICW, SW, but not SBO.	23.6%	21.1%	<$33.4k	>2 x Benefit	Screen out	Analysis case RCPLOCA determined the benefit from eliminating all RCP seal LOCAs to be <$33.4k. The modifications required to implement this alternative are judged to exceed this amount without having a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
12	Use existing hydro test pump for RCP seal injection	Independent seal injection source, without cost of a new system	23.6%	21.1%	<$33.4k	> Benefit	Screen out	Analysis case RCPLOCA determined the benefit from eliminating all RCP seal LOCAs to be <$33.4k. The modifications required to implement this alternative are judged to exceed this amount without having a specific cost estimate. (There is no onsite hydro pump with the necessary capacity, a permanent plant modification would be required to allow the pump to be aligned in the time window available, and procedure changes implemented to direct that it be aligned, and it is judged that this would cost more than $33.4k). This SAMA would yield no additional benefit from considering external events because the RCPs would be stopped in the event of an external initiator and no cooling is required to the RCP seals if they are stopped. Not cost-beneficial; cost is expected to exceed the benefit.
15	Add a third ICW pump	Reduce chance of loss of ICW leading to RCP seal LOCA	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	Analysis case ICW2 determined the benefit of adding an additional pump in parallel with the existing "B" pump to be <$1.1K. The costs associated with the plant modifications required to implement this alternative are judged to be significantly higher than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
16	Prevent makeup pump flow diversion from the relief valves	If relief valve opening causes a flow diversion large enough to prevent RCP seal injection, then modification can reduce frequency of loss of RCP seal cooling.	0.5%	Note 1	<$0.8k	>2 x Benefit	Screen out	HPI RV failures are not modeled as a failure mode in the ANO-1 model. This is judged to be NA at ANO-1 (makeup pump capacity sufficient to continue to supply seal injection in the unlikely event that a RV spuriously lifts). The ANO-1 PSA does consider a diversion of flow to the makeup tank. Eliminating this diversion path was estimated to reduce CDF by 5.1E-8 (0.5%) which translates to a benefit of approximately $0.7k (0.5% of the MAB of $145.4k). It is concluded that the risk benefit attained does not justify the cost of the proposed modification). Not cost-beneficial; cost is expected to exceed twice the benefit.
18	Procedures to stagger HPI pump use after a loss of SW	Allow high pressure injection to be extended after a loss of SW	5.4%	Note 1	<$7.9k	>2 x Benefit	Screen out	This suggestion was previously evaluated and discarded as overly burdensome and restrictive on operations. (Suggested change also screens as not cost-effective, since core damage is normally only delayed rather than averted. Since SW contribution is approximately 27% of core damage, and since SW core damage may be decreased by about 10% - 20% by the proposed change (more time available to restore SW) it was estimated that CDF might be reduced by 2.7% - 5.4% which suggests a value of the proposed change of approximately $7.9k (5.4% of MAB) which does not justify the expense of the proposed change. Not cost-beneficial; cost is expected to exceed twice the benefit.
20	Procedural guidance for use of cross-tied ICW or SW pumps	Can reduce the frequency of the loss of either of these.	2.7%	Note 1	<$4k	>2 x Benefit	Screen out	Per the ANO-1 PRA, the only operator failure which significantly affects the ANO-1 loss of SW/ICW CDF is failure to secure a RCP following a loss of SW event. This proposed change is also a specific suggestion and is evaluated with the other reactor seal LOCA suggestions. Based upon review of the ANO-1 PSA results, it is concluded that no other ICW/SW related training or procedure enhancements would reduce CDF by more than 2.7% (ICW/SW CDF is about 27% of CDF and would be reduced by less than 10% by any postulated procedure/training change, excluding procedure changes which ensure the RCPs are promptly tripped after a loss of SW event). The value of the proposed changes are then estimated as less than $4k (2.7% of MAB), which does not justify the associated cost of significant changes to ANO-1 emergency procedures or to operator training programs. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
21	Procedure & training enhancements in support system failure sequences	Potential improvement in success rate of operator actions after support system failures due to more procedural guidance on anticipating problems and coping.	2.7%	Note 1	<$4k	>2 x Benefit	Screen out	Per the ANO-1 PRA, the only operator failure which significantly affects the ANO-1 loss of SW/ICW CDF is failure to secure a RCP following a loss of SW event. This proposed change is also a specific suggestion and is evaluated with the other reactor seal LOCA suggestions. Based upon review of the ANO-1 PSA results, it is concluded that no other ICW/SW related training or procedure enhancements would reduce CDF by more than 2.7% (ICW/SW CDF is about 27% of CDF and would be reduced by less than 10% by any postulated procedure/training change, excluding procedure changes which ensure the RCPs are promptly tripped after a loss of SW event). The value of the proposed changes are then estimated as less than $4k (2.7% of MAB), which does not justify the associated cost of significant changes to ANO-1 emergency procedures or to operator training programs. Not cost-beneficial; cost is expected to exceed twice the benefit.
22	Improve ability to cool RHR heat exchangers	Reduced chance of loss of DHR by 1)Performing procedure and hardware modification to allow manual alignment of fire protection system to the ICW system, or 2)Installing an ICW header cross-tie	3.2%	0.6%	<$4k	>2 x Benefit	Screen out	ANO-1 already has significant crosstie capability in the SW system (e.g., the ability to supply cooling to either RHR heat exchanger from a particular SW pump). Per #3 (case ICW1) above, no cost-effective procedure changes were identified which would significantly reduce the SW CDF. Not cost-beneficial; cost is expected to exceed twice the benefit.
25	Procedures for temporary HVAC	Provides for improved credit to be taken for loss of HVAC sequences	0.1%	0.4%	<$0.2k	>2 x Benefit	Screen out	Analysis case DGHVAC determined the benefit of eliminating the diesel generator dependency on HVAC to be <$0.2k. The cost associated with developing a procedure for temporary HVAC combined with the purchase of the temporary equipment are significantly greater than the assessed benefit. Therefore the suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
31	Develop an enhanced drywell spray system	Would provide a redundant source of water to the containment to control containment pressure, when used in conjunction with containment heat removal	0.0%	100.0%	<$22.2K	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (The pre-construction cost for such a system was estimated as ~$1.5M for System 80). Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
32	Provide a dedicated existing drywell spray system	Identical to the previous concept, except that one of the existing spray loops would be used instead of developing a new spray system.	0.0%	100.0%	<$22.2K	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
34	Install a filtered containment vent to remove decay heat	Assuming injection is available (non-ATWS sequences), would provide alternate decay heat removal with the released fission products being scrubbed.	0.0%	100.0%	<$22.2K	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $20M (TVA); $10M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
35	Install an unfiltered hardened containment vent	Provides an alternate decay heat removal method (non-ATWS), which is not filtered	0.0%	100.0%	<$22.2K	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $20M (TVA)) This SAMA could result in an inadvertent unfiltered release and thus could increase public risk. Not cost-beneficial; cost is expected to exceed twice the benefit.
36	Create/enhance hydrogen igniters with independent power supply.	Use either a new, independent power supply, a non-safety grade portable generator, existing station batteries, or existing AC/DC independent power supplies such as the security system diesel. Would reduce hydrogen detonation at lower cost.	0.0%	100.0%	<$22.2K	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $6.1M (TVA, 1994); $1M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
37	Create a passive hydrogen ignition system	Reduce hydrogen detonation potential without requiring electric power	0.0%	100.0%	<$22.2K	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $780k (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
38	Create a giant concrete crucible with heat removal potential under the basemat to contain molten debris	A molten core escaping from the vessel would be contained within the crucible. The water cooling mechanism would cool the molten core, preventing a melt-through.	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $108M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
39	Create a water cooled rubble bed on the pedestal	This rubble bed would contain a molten core dropping onto the pedestal, and would allow the debris to be cooled.	0.0%	100.0%	<$22.2K	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $18M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
41	Enhance fire protection system and/or standby gas treatment system hardware and procedures	Improve fission product scrubbing in severe accidents	0.0%	100.0%	<$22.2K	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
42	Create a reactor cavity flooding system	Would enhance debris coolability, reduce core concrete interaction and provide fission product scrubbing	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $8.75M (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
43.2	Creating other options for reactor cavity flooding (Part b)	(b)Flood cavity via systems such as diesel driven fire pumps	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Note that this is either not feasible or prohibitively expensive with ANO-1 design, since reactor cavity flooding is not possible due to the open door at the bottom of the incore tunnel. This allows water to flow to the lower containment and be used for recirculation. Not cost-beneficial; cost is expected to exceed twice the benefit.
45	Provide a core debris control system	(Intended for ice-condenser plants): Would prevent the direct core debris attack of the primary containment steel shell by erecting a barrier between the seal table and containment shell.	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
46	Create a core melt source reduction system (COMSORS)	Place enough glass underneath the reactor vessel such that a molten core falling on the glass would melt and combine with the material. Subsequent spreading and heat removal from the vitrified compound would be facilitated, and concrete attack would not occur (such benefits are theorized in the reference).	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
47	Provide containment inerting capability	Would prevent combustion of hydrogen and carbon monoxide gases	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $10.9M (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.
48	Use fire water spray pump for containment spray	Redundant containment spray method without high cost	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Boron dilution impact would require evaluation). Not cost-beneficial; cost is expected to exceed twice the benefit.
49	Install a passive containment spray system	Containment spray benefits at a very high reliability, and without support systems	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
51	Increase containment design pressure	Reduce chance of containment overpressure	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
52	Increase the depth of the concrete basemat, or use an alternative concrete material to ensure melt through does not occur	Prevent basemat melt through	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
53	Provide a reactor vessel exterior cooling system.	Potential to cool a molten core before it causes vessel failure, if the lower head can be submerged in water.	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $2.5M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
54	Create another building, maintained at a vacuum to be connected to containment	In an accident, connecting the new building to containment would depressurize containment and reduce any fission product release.	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost >$10M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
55	Add ribbing to the containment shell	Would reduce the chance of buckling of containment under reverse pressure loading.	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
56	Reactor Building Liner Protective Barrier	A protective barrier inside the incore instrument tunnel or along the reactor building liner just beyond the tunnel could prevent certain types of containment failure, which could result in a notable reduction in the large release frequency.	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
57	Train operations crew for response to inadvertent actuation signals	Improves chances of a successful response to the loss of two 120V AC buses, which causes inadvertent signals.	1.1%	0.4%	<$1.5k	>2 x Benefit	Screen out	Analysis case SPURIOUS determined the benefit of eliminating all spurious SI and low pressurizer pressure signals to be <$1.5k. The costs of providing additional training significantly exceed the benefit to be gained. [Operation procedures 1203.36 DC(Loss of 125 V DC), 1203.37 (Abnormal ES Bus Voltage), and 1203.46 (Loss of Load Center) are available to provide operator guidance for loss of a vital AC or vital DC bus.] Not cost-beneficial; cost is expected to exceed twice the benefit.
60	Provide additional DC battery capability	Would ensure longer battery capability during a SBO, reducing frequency of long term SBO sequences.	3.9%	9.7%	<$7.1k	>2 x Benefit	Screen out	Analysis case DCGOOD determined the benefit of installing batteries with a 24 hour capacity to be <$7.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
61	Use fuel cells instead of lead-acid batteries	Extend DC power availability in a SBO	3.9%	9.7%	<$7.1k	>2 x Benefit	Screen out	Analysis case DCGOOD determined the benefit of installing batteries with a 24 hour capacity to be <$7.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $2M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
63	Improved bus cross tie ability	Improved AC power reliability	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with providing additional crosstie capability are judged to be significantly greater than the benefit that would be achieved. (ANO-1 has the ability to cross tie buses from red to green train in order to ensure an adequate power supply.) Not cost-beneficial; cost is expected to exceed twice the benefit.
64	Alternate battery charging capability	Improved DC power reliability. Either cross tie of AC buses, or a portable diesel-driven battery charger.	3.9%	9.7%	<$7.1k	>2 x Benefit	Screen out	Analysis case DCGOOD determined the benefit of installing batteries with a 24 hour capacity to be <$7.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $107k (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.
66	Replace batteries	Improved reliability	3.9%	9.7%	<$7.1k	>2 x Benefit	Screen out	Analysis case DCGOOD determined the benefit of installing batteries with a 24 hour capacity to be <$7.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
67	Create AC power cross tie capability across units at a multi-unit site	Improved AC power reliability	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications and procedures required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
69	Develop procedures to repair or change out failed 4KV breakers	Offers a recovery path from a failure of breakers that perform transfer of 4.16 kV non-emergency buses from unit station service transformers to system station service transformers, leading to loss of emergency AC power (i.e., in conjunction with failures of the diesel generators).	1.2%	0.5%	<$0.9k	>2 x Benefit	Screen out	Analysis case BREAKER removed all bus infeed, cross-tie, and diesel generator output breakers from the fault tree model. This simulates having perfectly reliable circuit breakers. The benefit shown in this case is <$1k. The cost of developing procedures and purchasing spare breakers is greater than the benefit. When spare breakers are on hand, existing procedures can be used to set up the circuit breakers for use in an emergency. (ANO-1procedure 1107.002 exists to provide guidance to swap breakers for 4160V during an emergency). Not cost-beneficial; cost is expected to exceed twice the benefit.
70	Emphasize steps in recovery of offsite power after a SBO.	Reduced human error probability of offsite power recovery.	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with procedural and training enhancements are greater than this amount. Not cost-beneficial; cost is expected to exceed twice the benefit.
73	Install gas turbine generators	Improve on-site AC power reliability	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
74	Install tornado protection on gas turbine generator	If the unit has a gas turbine, the tornado-induced SBO frequency would be reduced.	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	ANO-1 has already installed backup power capability that has reduced loss of offsite power to a negligible contributor to ANO-1 risk. Analysis case NO-LOSP indicates a maximum benefit of <$1.1k for a modification which further improves the AC reliability. Not cost-beneficial; cost is expected to exceed twice the benefit.
75	Create a river water backup for diesel cooling.	Provides redundant source of diesel cooling.	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
76	Use firewater as a backup for diesel cooling	Redundancy in diesel support systems	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications and procedures required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
77	Provide a connection to alternate offsite power source	Increase offsite power redundancy	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
78	Implement underground offsite power lines	Could improve offsite power reliability, particularly during severe weather.	0.4%	2.1%	<$1.1k	>2 x Benefit	Screen out	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
81	Install a redundant spray system to depressurize the primary system during a SGTR.	Enhanced depressurization ability during SGTR.	3.1%	31.0%	<$11k	>2 x Benefit	Screen out	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. (See also item #151) (Estimated cost $5M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
82	Improved SGTR coping abilities	Improved instrumentation to detect SGTR, or additional systems to scrub fission product releases.	3.1%	31.0%	<$11k	>2 x Benefit	Screen out	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. (ANO-1 already has N-16 monitors as well as alternative means for evaluating SGTR events. (Estimated cost $9.5M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
83	Adding other SGTR coping features. Options: A) SG shell-side HR System. B) System to return SG RV disch to Containment. C) Increase psr capacity of SG shell side	(a)A highly reliable (closed loop) steam generator shell-side heat removal system that relies on natural circulation and stored water sources, (b)a system which returns the discharge from the steam generator relief valve back to the primary containment, (c)an increased pressure capability on the steam generator shell side with corresponding increase in the safety valve setpoints.	3.1%	31.0%	<$11k	>2 x Benefit	Screen out	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. (Option a would have some benefit for non SGTR sequences, but would clearly cost much more than the ANO-1 MAB of $226K). Not cost-beneficial; cost is expected to exceed twice the benefit.
84	Increase secondary side pressure capacity such that a SGTR would not cause the relief valves to lift	SGTR sequences would not have a direct release pathway	3.1%	31.0%	<$11k	>2 x Benefit	Screen out	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
85	Replace steam generators with new design	Lower frequency of SGTR	3.1%	31.0%	<$11k	>2 x Benefit	Screen out	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
87	Direct steam generator flooding after a SGTR, prior to core damage.	Would provide for improved scrubbing of SGTR releases.	3.1%	31.0%	<$11k	>2 x Benefit	Screen out	No impact on CDF, but release can be reduced if ruptured SG tubes are kept covered. New guidance from the Owner's Group is being incorporated into the EOPs. Both steam generators are used for heat removal following a SGTR to provide natural circulation cooling if offsite power is lost. Can flood if necessary, but may not help depending on location of tube failure, cannot flood to where level may impact the turbine driven pump. No further action is required. Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k and only a fraction of this benefit would be achieved if this suggestion were implemented. Since the assessed benefit is much less than the estimated cost this suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
88	Implement a maintenance practice that inspects 100% of the tubes in a steam generator	Reduce chances of tube rupture	3.1%	31.0%	<$11k	>2 x Benefit	Screen out	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k (and not all tube ruptures would be eliminated by expanding the inspection scope). The costs required to implement this suggestion are therefore judged to be significantly greater than the benefit achieved. (Estimated cost $1.5M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
89	Locate RHR inside of containment	Would prevent ISLOCA out the RHR pathway	0.4%	4.4%	<$1.6k	>2 x Benefit	Screen out	Per the ANO-1 PSA (Analysis case ISL) minimal benefit is attainable even if the proposed change were assumed to reduce the ISLOCA frequency to zero (approximately $1600). Since the cost of the proposed modification is many orders of magnitude greater than the assessed benefit, the proposed SAMA is screened out. Not cost-beneficial; cost is expected to exceed twice the benefit.
90	Provide self-actuating containment isolation valves	For plants that don’t have this, it would reduce the frequency of isolation failure	0.0%	100.0%	<$22.2k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2k (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
92	Increase frequency of valve leak testing	Decrease ISLOCA frequency	~0%	~0.4%	<$0.2k	>2 x Benefit	Screen out	Since ANO-1 has pressure detectors between the first two pressure isolation valves for the dominant ISLOCA scenarios (see #91 above), it is judged that ISLOCA frequency would not be significantly reduced by the proposed modification. Therefore the benefit of the suggested modification is estimated as less than 10% of a change which would eliminate ISLOCA scenarios. The value of the change is then estimated as less than $160 (10% of the benefit from analysis case ISL). Since the cost of increased testing is much more than the assessed benefit the suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
93	Improve operator training on ISLOCA coping	Decrease ISLOCA effects	0.4%	4.4%	<$1.6k	>2 x Benefit	Screen out	Per analysis case ISL the risk benefit attainable if the ISLOCA CDF is reduced to zero is approximately $1600. Since the preparation and implementation of additional ISLOCA training would cost much more than the estimated benefit this suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
94	Install relief valves in the ICW system	Would relieve pressure buildup from an RCP thermal barrier tube rupture, preventing an ISLOCA	~0%	~0%	<$0.2k	>2 x Benefit	Screen out	This scenario was estimated as 3E-9 contributor to core damage and containment bypass core damage in the ANO-1 ISLOCA analysis. The value of the change is estimated as a 6.7% reduction in ISLOCA frequency. Per the ANO-1 PSA (analysis case ISL) the value of the risk reduction is estimated as approximately $103 (0.067*$1600). Since the cost of the proposed modification is much greater than the assessed benefit, the proposed modification was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
95	Provide leak testing of valves in ISLOCA paths	At Kewaunee, four MOVs isolating RHR from the RCS were not leak tested. Will help reduce ISLOCA frequency	0.4%	4.4%	<$1.6k	>2 x Benefit	Screen out	Per analysis case ISL the risk benefit attainable if the ISLOCA CDF is reduced to zero is approximately $1600. Since the preparation and implementation of additional ISLOCA training would cost much more than the estimated benefit this suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
96	Revise EOPs to improve ISLOCA identification	Salem had a scenario in which an RHR ISLOCA could direct initial leakage back to the PRT, giving indication that the LOCA was inside containment. Procedure enhancement would ensure LOCA outside containment would be observed.	0.4%	4.4%	<$1.6k	>2 x Benefit	Screen out	Per the ANO-1 PSA (analysis case ISL) minimal benefit is attainable even if the training/procedure change were assumed to reduce the ISLOCA frequency to zero (approximately $1600). Therefore the proposed suggestion is screened out as not cost-effective. Not cost-beneficial; cost is expected to exceed twice the benefit.
97	Ensure all ISLOCA releases are scrubbed	Would scrub ISLOCA releases. One suggestion was to plug drains in the break area so the break point would cover with water.	0.4%	4.4%	<$1.6k	>2 x Benefit	Screen out	Analysis case ISL determined the benefit of eliminating all ISLOCA to be $1,600. The costs of the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
98	Add redundant and diverse limit switch to each containment isolation valve.	Enhanced isolation valve position indication, which would reduce frequency of containment isolation failure and ISLOCAs.	0.4%	100.0%	<$24k	>2 x Benefit	Screen out	The maximum benefit obtained by totally eliminating offsite release is $22.2k (with no core damage reduction, $24K if ISLOCA frequency was assumed to be significantly decreased; see analysis case ISL). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $1M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
107	Install digital feedwater upgrade	Reduces chance of loss of MFW following a plant trip.	3.2%	0.6%	<$4.1k	>2 x Benefit	Screen out	Analysis case FW determined the benefit of eliminating all feedwater initiators (Loss of power conversion system and excessive feedwater flow) to be <$4.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
114	Provide portable generators to be hooked in to the turbine driven AFW, after battery depletion	Extend AFW availability in a SBO (assuming the turbine-driven AFW requires DC power)	1.0%	4.3%	<$2.3k	>2 x Benefit	Screen out	Analysis case PDSTDPDC estimated the risk reduction benefit of this suggested change as <$2.3k. Station Blackout is already a negligible contributor to ANO-1 core damage risk due to installation of a diverse backup DG. Since the cost of the suggested change is judged to be much greater than the assessed benefit the change was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
115	Add a motor train of AFW to the steam trains.	For PWRs that do not have any motor trains of AFW, this can increase reliability in non-SBO sequences.	Note 2	Note 2	<MAB	>2MAB	Screened out	Cost of adding another motor driven AFW train would be expected to exceed 2 MAB. ANO-1 already has a motor driven pump in combination with a turbine driven pump. Not cost-beneficial; cost is expected to exceed twice the benefit.
121	Create passive secondary side coolers	Provide a passive heat removal loop with a condenser and heat sink. Would reduce CDF from the loss of feedwater.	Note 2	Note 2	<MAB	>2MAB	Screen out	The maximum benefit for reducing core damage to zero is $145.4k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
124	Provide an additional high pressure injection pump with independent diesel	Reduce frequency of core melt from small LOCA sequences, and from SBO sequences.	42.0%	Note 1	<$61.1k	>2 x Benefit	Screen out	Review of the ANO-1 PSA results indicates that 5.52E-6/yr of the total CDF could potentially be averted if a perfect HPI system reliability could be achieved. However 2.48E-6 of the 5.52E-6 HPI core damage is due to total loss of service water. Even if the diverse HPI pump were independent of SW cooling, SW cooling is required for recirculation (DHR HX cooling and cooling to the LPI pumps) therefore these sequences will still result in core damage unless SW is eventually recovered. Assuming 50% of SW faults are recovered prior to core damage the decreased core damage from a perfect HPI system is estimated as 4.28E-6 (3.04E-6 + 0.5 * 2.48E-6) which represents a 42% reduction in CDF. The value of the proposed modification is then estimated as 42% of the MAB ($145.4K) or as $61k which is much less than the estimated cost of the modification. (Estimated cost $2.2M (System 80+), $3.5M (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.
125	Install independent AC high pressure injection system	Would allow make up and feed and bleed capabilities during a SBO	42.0%	Note 1	<$61.1k	>2 x Benefit	Screen out	Review of the ANO-1 PSA results indicates that 5.52E-6/yr of the total CDF could potentially be averted if a perfect HPI system reliability could be achieved. However 2.48E-6 of the 5.52E-6 HPI core damage is due to total loss of service water. Even if the diverse HPI pump were independent of SW cooling, SW cooling is required for recirculation (DHR HX cooling and cooling to the LPI pumps) therefore these sequences will still result in core damage unless SW is eventually recovered. Assuming 50% of SW faults are recovered prior to core damage the decreased core damage from a perfect HPI system is estimated as 4.28E-6 (3.04E-6 + 0.5 * 2.48E-6) which represents a 42% reduction in CDF. The value of the proposed modification is then estimated as 42% of the MAB ($145.4K) or as $61k which is much less than the estimated cost of the modification. Not cost-beneficial; cost is expected to exceed twice the benefit.
129	Emphasize timely recirc swapover in operator training	Reduce human error probability of recirculation failure	<37.1%	<6.8%	<$47.2k, possibly as low as <$31.5k	<2 x Benefit	This SAMA does not screen out.	Per analysis case PDSHPROA the benefit of a change that reduced the human error probability for recirculation to zero was estimated as $47.2k. If increased training is assumed to reduce the human error probability by a factor of 3, then the benefit of increased training would be estimated as $31.5K (47.2k * 2/3). The proposed suggestion does not screen out.
138	Create automatic swapover to recirculation on BWST depletion	Would remove human error contribution from recirculation failure.	37.1%	6.8%	<$47.2k	>2 x Benefit	Screen out	Per analysis case PDSHPROA the benefit of this proposed modification was estimated as $47.2k. The engineering, procurement and installation of controls to automate the swapover of BWST to recirc from the sump would include BWST level monitors, ESFAS upgrade and interlock controls on sump and BWST valves. These changes in addition to operational procedure changes and training would well exceed 2 X $47.2k (assume internal and external effects). No cost estimate needed. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
139	Modify EOPs for ability to align diesel power to more air compressors.	For plants which do not have diesel power to all normal and backup air compressors, this change allows increased reliability of instrument air after a LOP.	0.7%	7.0%	<$2.5k	>2 x Benefit	Screen out	Analysis case INSTAIR2 removed all power dependencies/support for the air compressors. The benefit was determined to be <$2.5k. The costs of the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
140	Replace old air compressors with more reliable ones.	Improve reliability and increase availability of instrument air compressors.	0.9%	9.4%	<$3.4k	>2 x Benefit	Screen out	Analysis case INSTAIR1 determined the benefit of perfectly reliable air compressors to be <$3.4k. The costs of the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
142	Install MG set trip breakers in control room	Provides trip breakers for the motor generator sets in the control room. Currently, at Watts Bar, an ATWS would require an immediate action outside the control room to trip the MG sets. Would reduce ATWS CDF	5.6%	Note 1	<$8.1k	>2 x Benefit	Screen out	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1k [145.4K (MAB) * 5.7E-7/1.027E-5]. Since ANO-1 ATWS risk is dominated by mechanical failures of the rods rather than by electrical failure, the proposed modification would provide only a fraction of this benefit. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
143	Add capability to remove power from the bus powering the control rods	Decrease time to insert control rods when if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	5.6%	Note 1	<$8.1k	>2 x Benefit	Screen out	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1k [145.4K (MAB) * 5.7E-7/1.027E-5]. Since ANO-1 ATWS risk is dominated by mechanical failures of the rods rather than by electrical failure, the proposed modification would provide only a fraction of this benefit. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. (Estimated cost $143k (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
147	Add a system of relief valves that prevents any equipment damage from a pressure spike during an ATWS	Would improve equipment availability after an ATWS.	5.6%	Note 1	<$8.1k	>2 x Benefit	Screen out	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1K [145.4K (MAB) * 5.7E-7/1.027E-5]. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
148	Create a boron injection system to back up the mechanical control rods.	Provides a redundant means to shut down the reactor.	5.6%	Note 1	<$8.1k	>2 x Benefit	Screen out	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1K [145.4K (MAB) * 5.7E-7/1.027E-5]. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
149	Provide an additional I&C system (e.g., AMSAC).	Improve I&C redundancy and reduce ATWS frequency.	5.6%	Note 1	<$8.1k	>2 x Benefit	Screen out	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1K [145.4K (MAB) * 5.7E-7/1.027E-5]. Since ANO-1 ATWS risk is dominated by mechanical failures of the rods rather than by electrical failure, the proposed modification would provide only a fraction of this benefit. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
151	Create/enhance reactor coolant system depressurization ability	Either with a new depressurization system, or with existing PORVs, head vents and secondary side valve, RCS depressurization would allow low pressure ECCS injection. Even if core damage occurs, low RCS pressure alleviates some concerns about high pressure melt injection.	1.8%	18.1%	<$6.4k	>2 x Benefit	Screen out	Analysis case PDSRCD evaluated the benefit attained if perfect depressurization capability is provided to be $6.4k. (Since ANO-1has high head ECCS pumps, depressurization is only required for SGTR sequences). Since the cost of the proposed change would cost much more than the assessed benefit the change is screened out from further consideration. (Estimated cost for new system $4.6M (TVA), $500k to enhance existing system (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 SUMMARY OF ANO-1 SAMAs CONSIDERED IN COST-BENEFIT ANALYSIS

SAMA Number	Potential Improvement	Discussion	Reduction in CDF (Bounding)	Reduction in Person-Rem Offsite (Bounding)	Benefit (Bounding)	Estimated Cost	Conclusion	Basis for Conclusion
152	Make procedural changes only for the RCS depressurization option	Reduce RCS pressure without cost of a new system	1.8%	18.1%	<$6.4k	>2 x Benefit	Screen out	A sensitivity run assuming perfect depressurization capability indicates that negligible value (<$6.4k) is attained by revising the SGTR procedure to credit additional depressurization methods (see #151, case PDSRCD). Therefore the cost of a significant EOP change is not justified by the risk reduction attained. Not cost-beneficial; cost is expected to exceed twice the benefit.
155	Add secondary side guard pipes up to the MSIVs.	Would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. Would also guard against or prevent consequential multiple SGTR following a main steam line break event.	~0%	~0%	~$0	>2 x Benefit	Screen out	Analysis case NOSLB determined the benefit of eliminating all steam/feedwater line breaks to be negligible. Since the cost of the proposed change is much greater than the risk reduction benefit attained the suggestion was screened out from further consideration. (Estimated cost $1.1M (System 80)). Not cost-beneficial; cost is expected to exceed twice the benefit.
156	Add digital large break LOCA protection	Upgrade plant instrumentation and logic to improve the capability to identify symptoms/precursors of a large break LOCA (a leak before break).	34.4%	5.9%	<$43.6k	>2 x Benefit	Screen out	Analysis case NO-A determined the benefit of eliminating all Large Break LOCA initiators to be <$43.6K. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
157	Increase seismic capacity of the plant to a HCLPF of twice the SSE	Reduced seismic CDF	Note 2	Note 2	<MAB	>2 MAB	Screen out	The benefit achieved is estimated as less than the ANO-1 MAB of $145.4K. (Seismic CDF is judged to have a CDF significantly less than the internal CDF). ANO-1 has performed an analysis to determine that the existing plant design (SSE = 0.2g) is adequate for a 0.3g earthquake. This analysis cost ~$750k. It is expected that significant plant modifications would be necessary to increase the capacity to 0.4g and that the cost would greatly exceed 2MAB. Not cost-beneficial; cost is expected to exceed twice the benefit.

Note 1 Reduction in CDF estimated as a percentage reduction therefore reduction in person-rem was not directly calculated.

Note 2 Reduction in CDF was not estimated because the cost is expected to be much greater that MAB and the item was screened.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
1	Cap downstream piping of normally closed ICW drain and vent valves	<$4k	>2 x Benefit	Screen out	<$8k	<=$6.6k	<$4.5k	<$6.7k	<$1.8k	Loss of ICW is included as part of the Loss of Power Conversion System initiating event. Analysis case ICW1 determined the benefit of eliminating all causes of this initiating event to be <$4K. The costs associated with the needed procedure changes and/or plant modifications required to implement this alternative are greater than the benefit. Not cost-beneficial; cost is expected to exceed twice the benefit.
3	Enhance Loss of ICW procedure to present desirability of cooling down RCS prior to seal LOCA	<$4k	>2 x Benefit	Screen out	<$8k	<=$6.6k	<$4.5k	<$6.7k	<$1.8k	Based on the low risk reduction worth of the ANO-1 ICW system (see #1 and #15, case ICW1), the maximum benefit of a procedure change which eliminates or mitigates all loss of ICW events is less than $4k (ANO-1 is not as susceptible to loss of ICW as many plants as the ECCS pumps are cooled directly by service water and therefore: (a) seal cooling can continue unabated following a loss of ICW event via continued seal injection; (b) a seal LOCA initiated by loss of ICW can be mitigated). Considering that: (a) the estimate above was calculated in a very conservative manner [assumed to eliminate all loss of PCS initiating events (%T2)] (b) the ability to prevent/ mitigate ICW events from additional training/ procedure changes is limited, it is clear that the cost of the suggestion is not justified by the associated risk reduction. Not cost-beneficial; cost is expected to exceed twice the benefit.
4	Additional training on the Loss of ICW	<$4k	>2 x Benefit	Screen out	<$8k	<=$6.6k	<$4.5k	<$6.7k	<$1.8k	Based on the low risk reduction worth of the ANO-1 ICW system (see #1 and #15, case ICW1), the maximum benefit of a procedure change which eliminates or mitigates all loss of ICW events is less than $4K (ANO-1 is not as susceptible to loss of ICW as many plants as the ECCS pumps are cooled directly by service water and therefore: (a) seal cooling can continue unabated following a loss of ICW event via continued seal injection; (b) a seal LOCA initiated by loss of ICW can be mitigated). Considering that: (a) the estimate above was calculated in a very conservative manner [assumed to eliminate all loss of PCS initiating events (%T2)] (b) the ability to prevent/ mitigate ICW events from additional training/ procedure changes is limited, it is clear that the cost of the suggestion is not justified by the associated risk reduction. Not cost-beneficial; cost is expected to exceed twice the benefit.

5 The value of the "benefit" considered in this column is the baseline value.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
7	Increase makeup pump lube oil capacity	<$33k	>2 x Benefit	Screen out	<$66k	<$50.9k	<$36.2k	<$53.2k	<$14.6k	Analysis case LOSWTOMU determined the benefit from eliminating all dependence of MU pumps on SW to be <$33k. In order to implement this alternative, hardware changes would be necessary to increase the oil capacity, add oil-air heat exchangers, increase room cooling capacity. Procedures would need to be modified. The combined cost of these changes will be greater than the benefit obtained. Not cost-beneficial; cost is expected to exceed twice the benefit.
9	Provide additional SW pump	<$39.3k	>2 x Benefit	Screen out	<$78.6k	<=$61.2k	<$43.7k	<$64.2k	<$17.7k	The maximum benefit from a plant change that reduces the CDF due to SW failures to zero is estimated as approximately $39.3k (27% of MAB, as approximately 27% of CDF can be attributed to SW failures). The actual benefit is estimated as less than $39.3k, since loss of SW scenarios cannot be entirely eliminated by adding an additional pump. The cost of adding an additional service water pump is judged to be greater than this amount, even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
10	Create an independent RCP seal injection system, with dedicated diesel	<$33.4k	>2 x Benefit	Screen out	<$66.8k	<=$52.5k	<$37.2k	<$54.8k	<$14.9k	Analysis case RCPLOCA determined the benefit from eliminating all RCP seal LOCAs to be <$33.4k. The modifications required to implement this alternative are judged to exceed this amount without having a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
11	Create an independent RCP seal injection system, without dedicated diesel	<$33.4k	>2 x Benefit	Screen out	<$66.8k	<=$52.5k	<$37.2k	<$54.8k	<$14.9k	Analysis case RCPLOCA determined the benefit from eliminating all RCP seal LOCAs to be <$33.4k. The modifications required to implement this alternative are judged to exceed this amount without having a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
12	Use existing hydro test pump for RCP seal injection	<$33.4k	>2 x Benefit	Screen out	<$66.8k	<=$52.5k	<$37.2k	<$54.8k	<$14.9k	Analysis case RCPLOCA determined the benefit from eliminating all RCP seal LOCAs to be <$33.4k. The modifications required to implement this alternative are judged to exceed this amount without having a specific cost estimate. (There is no onsite hydro pump with the necessary capacity, a permanent plant modification would be required to allow the pump to be aligned in the time window available, and procedure changes implemented to direct that it be aligned, and it is judged that this would cost more than $33.4k). This SAMA would yield no additional benefit from considering external events because the RCPs would be stopped in the event of an external initiator and no cooling is required to the RCP seals if they are stopped. Not cost-beneficial; cost is expected to exceed the benefit.
15	Add a third ICW pump	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.1k	<$1.6k	<$0.6k	Analysis case ICW2 determined the benefit of adding an additional pump in parallel with the existing "B" pump to be <$1.1K. The costs associated with the plant modifications required to implement this alternative are judged to be significantly higher than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
16	Prevent makeup pump flow diversion from the relief valves	<$0.8k	>2 x Benefit	Screen out	<$1.5k	<=$1.2k	<$0.9k	<$1.2k	<$0.4k	HPI RV failures are not modeled as a failure mode in the ANO-1 model. This is judged to be NA at ANO-1 (makeup pump capacity sufficient to continue to supply seal injection in the unlikely event that a RV spuriously lifts). The ANO-1 PSA does consider a diversion of flow to the makeup tank. Eliminating this diversion path was estimated to reduce CDF by 5.1E-8 (0.5%) which translates to a benefit of approximately $0.7k (0.5% of the MAB of $145.4k). It is concluded that the risk benefit attained does not justify the cost of the proposed modification). Not cost-beneficial; cost is expected to exceed twice the benefit.
18	Procedures to stagger HPI pump use after a loss of SW	<$7.9k	>2 x Benefit	Screen out	<$15.8k	<=$12.3k	<$8.8k	<$12.9k	<$3.6k	This suggestion was previously evaluated and discarded as overly burdensome and restrictive on operations. (Suggested change also screens as not cost-effective, since core damage is normally only delayed rather than averted. Since SW contribution is approximately 27% of core damage, and since SW core damage may be decreased by about 10% - 20% by the proposed change (more time available to restore SW) it was estimated that CDF might be reduced by 2.7% - 5.4% which suggests a value of the proposed change of approximately $7.9k (5.4% of MAB) which does not justify the expense of the proposed change. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
20	Procedural guidance for use of cross-tied ICW or SW pumps	<$4k	>2 x Benefit	Screen out	<$8k	<=$6.2k	<$4.4k	<$6.5k	<$1.8k	Per the ANO-1 PRA, the only operator failure which significantly affects the ANO-1 loss of SW/ICW CDF is failure to secure a RCP following a loss of SW event. This proposed change is also a specific suggestion and is evaluated with the other reactor seal LOCA suggestions. Based upon review of the ANO-1 PSA results, it is concluded that no other ICW/SW related training or procedure enhancements would reduce CDF by more than 2.7% (ICW/SW CDF is about 27% of CDF and would be reduced by less than 10% by any postulated procedure/training change, excluding procedure changes which ensure the RCPs are promptly tripped after a loss of SW event). The value of the proposed changes are then estimated as less than $4k (2.7% of MAB), which does not justify the associated cost of significant changes to ANO-1 emergency procedures or to operator training programs. Not cost-beneficial; cost is expected to exceed twice the benefit.
21	Procedure & training enhancements in support system failure sequences	<$4k	>2 x Benefit	Screen out	<$8k	<=$6.2k	<$4.4k	<$6.5k	<$1.8k	Per the ANO-1 PRA, the only operator failure which significantly affects the ANO-1loss of SW/ICW CDF is failure to secure a RCP following a loss of SW event. This proposed change is also a specific suggestion and is evaluated with the other reactor seal LOCA suggestions. Based upon review of the ANO-1 PSA results, it is concluded that no other ICW/SW related training or procedure enhancements would reduce CDF by more than 2.7% (ICW/SW CDF is about 27% of CDF and would be reduced by less than 10% by any postulated procedure/training change, excluding procedure changes which ensure the RCPs are promptly tripped after a loss of SW event). The value of the proposed changes are then estimated as less than $4k (2.7% of MAB), which does not justify the associated cost of significant changes to ANO-1 emergency procedures or to operator training programs. Not cost-beneficial; cost is expected to exceed twice the benefit.
22	Improve ability to cool RHR heat exchangers	<$4k	>2 x Benefit	Screen out	<$8k	<=$6.6k	<$4.5k	<$6.7k	<$1.8k	ANO-1 already has significant crosstie capability in the SW system (e.g, the ability to supply cooling to either RHR heat exchanger from a particular SW pump). Per #3 (case ICW1) above, no cost-effective procedure changes were identified which would significantly reduce the SW CDF. Not cost-beneficial; cost is expected to exceed twice the benefit.
25	Procedures for temporary HVAC	<$0.2k	>2 x Benefit	Screen out	<$0.4k	<=$0.3k	<$0.2k	<$0.3k	<$0.1k	Analysis case DGHVAC determined the benefit of eliminating the diesel generator dependency on HVAC to be <$0.2k. The cost associated with developing a procedure for temporary HVAC combined with the purchase of the temporary equipment are significantly greater than the assessed benefit. Therefore the suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
31	Develop an enhanced drywell spray system	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (The pre-construction cost for such a system was estimated as ~$1.5M for System 80). Not cost-beneficial; cost is expected to exceed twice the benefit.
32	Provide a dedicated existing drywell spray system	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
34	Install a filtered containment vent to remove decay heat	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $20M (TVA); $10M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
35	Install an unfiltered hardened containment vent	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $20M (TVA)) This SAMA could result in an inadvertent unfiltered release and thus could increase public risk. Not cost-beneficial; cost is expected to exceed twice the benefit.
36	Create/enhance hydrogen igniters with independent power supply.	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $6.1M (TVA, 1994); $1M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
37	Create a passive hydrogen ignition system	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $780k (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
38	Create a giant concrete crucible with heat removal potential under the basemat to contain molten debris	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $108M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
39	Create a water cooled rubble bed on the pedestal	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $18M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
41	Enhance fire protection system and/or standby gas treatment system hardware and procedures	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
42	Create a reactor cavity flooding system	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $8.75M (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
43.2	Creating other options for reactor cavity flooding (Part b)	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Note that this is either not feasible or prohibitively expensive with ANO-1 design, since reactor cavity flooding is not possible due to the open door at the bottom of the incore tunnel. This allows water to flow to the lower containment and be used for recirculation. Not cost-beneficial; cost is expected to exceed twice the benefit.
45	Provide a core debris control system	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
46	Create a core melt source reduction system (COMSORS)	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
47	Provide containment inerting capability	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $10.9M (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.
48	Use fire water spray pump for containment spray	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Boron dilution impact would require evaluation). Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
49	Install a passive containment spray system	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
51	Increase containment design pressure	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
52	Increase the depth of the concrete basemat, or use an alternative concrete material to ensure melt through does not occur	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
53	Provide a reactor vessel exterior cooling system.	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $2.5M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
54	Create another building, maintained at a vacuum to be connected to containment	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost >$10M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
55	Add ribbing to the containment shell	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
56	Reactor Building Liner Protective Barrier	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2K (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
57	Train operations crew for response to inadvertent actuation signals	<$1.5k	>2 x Benefit	Screen out	<$3k	<=$2.4k	<$1.7k	<$2.5k	<$0.6k	Analysis case SPURIOUS determined the benefit of eliminating all spurious SI and low pressurizer pressure signals to be <$1.5k. The costs of providing additional training significantly exceed the benefit to be gained. [Operation procedures 1203.36 DC(Loss of 125 V DC), 1203.37 (Abnormal ES Bus Voltage), and 1203.46 (Loss of Load Center) are available to provide operator guidance for loss of a vital AC or vital DC bus.] Not cost-beneficial; cost is expected to exceed twice the benefit.
60	Provide additional DC battery capability	<$7.1k	>2 x Benefit	Screen out	<$14.2k	<=$10.3k	<$7.7k	<$11.2k	<$3.4k	Analysis case DCGOOD determined the benefit of installing batteries with a 24 hour capacity to be <$7.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
61	Use fuel cells instead of lead-acid batteries	<$7.1k	>2 x Benefit	Screen out	<$14.2k	<=$10.3k	<$7.7k	<$11.2k	<$3.4k	Analysis case DCGOOD determined the benefit of installing batteries with a 24 hour capacity to be <$7.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $2M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
63	Improved bus cross tie ability	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.2k	<$1.6k	<$0.6k	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with providing additional crosstie capability are judged to be significantly greater than the benefit that would be achieved. (ANO-1 has the ability to cross tie buses from red to green train in order to ensure an adequate power supply.) Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
64	Alternate battery charging capability	<$7.1k	>2 x Benefit	Screen out	<$14.2k	<=$10.3k	<$7.7k	<$11.2k	<$3.4k	Analysis case DCGOOD determined the benefit of installing batteries with a 24 hour capacity to be <$7.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $107k (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.
66	Replace batteries	<$7.1k	>2 x Benefit	Screen out	<$14.2k	<=$10.3k	<$7.7k	<$11.2k	<$3.4k	Analysis case DCGOOD determined the benefit of installing batteries with a 24 hour capacity to be <$7.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
67	Create AC power cross tie capability across units at a multi-unit site	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.2k	<$1.6k	<$0.6k	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications and procedures required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
69	Develop procedures to repair or change out failed 4KV breakers	<$0.9k	>2 x Benefit	Screen out	<$1.8k	<=$1.4k	<$1k	<$1.5k	<$0.5k	Analysis case BREAKER removed all bus infeed, cross-tie, and diesel generator output breakers from the fault tree model. This simulates having perfectly reliable circuit breakers. The benefit shown in this case is <$1k. The cost of developing procedures and purchasing spare breakers is greater than the benefit. When spare breakers are on hand, existing procedures can be used to set up the circuit breakers for use in an emergency. (ANO-1procedure 1107.002 exists to provide guidance to swap breakers for 4160V during an emergency). Not cost-beneficial; cost is expected to exceed twice the benefit.
70	Emphasize steps in recovery of offsite power after a SBO.	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.2k	<$1.6k	<$0.6k	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with procedural and training enhancements are greater than this amount. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
73	Install gas turbine generators	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.2k	<$1.6k	<$0.6k	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
74	Install tornado protection on gas turbine generator	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.2k	<$1.6k	<$0.6k	ANO-1 has already installed backup power capability that has reduced loss of offsite power to a negligible contributor to ANO-1 risk. Analysis case NO-LOSP indicates a maximum benefit of <$1.1k for a modification which further improves the AC reliability. Not cost-beneficial; cost is expected to exceed twice the benefit.
75	Create a river water backup for diesel cooling.	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.2k	<$1.6k	<$0.6k	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
76	Use firewater as a backup for diesel cooling	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.2k	<$1.6k	<$0.6k	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications and procedures required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
77	Provide a connection to alternate offsite power source	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.2k	<$1.6k	<$0.6k	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
78	Implement underground offsite power lines	<$1.1k	>2 x Benefit	Screen out	<$2.2k	<=$1.4k	<$1.2k	<$1.6k	<$0.6k	Analysis case NO-LOSP determined the benefit of eliminating all Loss of Offsite Power initiators to be <$1.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
81	Install a redundant spray system to depressurize the primary system during a SGTR.	<$11k	>2 x Benefit	Screen out	<$22k	<=$13.3k	<$11.4k	<$16.2k	<$5.8k	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. (See also item #151) (Estimated cost $5M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
82	Improved SGTR coping abilities	<$11k	>2 x Benefit	Screen out	<$22k	<=$13.3k	<$11.4k	<$16.2k	<$5.8k	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. (ANO-1 already has N-16 monitors as well as alternative means for evaluating SGTR events. (Estimated cost $9.5M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
83	Adding other SGTR coping features. Options: A) SG shell-side HR System. B) System to return SG RV disch to Containment. C) Increase psr capacity of SG shell side	<$11k	>2 x Benefit	Screen out	<$22k	<=$13.3k	<$11.4k	<$16.2k	<$5.8k	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. (Option a would have some benefit for non SGTR sequences, but would clearly cost much more than the ANO-1 MAB of $226K). Not cost-beneficial; cost is expected to exceed twice the benefit.
84	Increase secondary side pressure capacity such that a SGTR would not cause the relief valves to lift	<$11k	>2 x Benefit	Screen out	<$22k	<=$13.3k	<$11.4k	<$16.2k	<$5.8k	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
85	Replace steam generators with new design	<$11k	>2 x Benefit	Screen out	<$22k	<=$13.3k	<$11.4k	<$16.2k	<$5.8k	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k. The plant modifications required to implement this alternative are judged to be significantly greater than this, even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
87	Direct steam generator flooding after a SGTR, prior to core damage.	<$11k	>2 x Benefit	Screen out	<$22k	<=$13.3k	<$11.4k	<$16.2k	<$5.8k	No impact on CDF, but release can be reduced if ruptured SG tubes are kept covered. New guidance from the Owner's Group is being incorporated into the EOPs. Both steam generators are used for heat removal following a SGTR to provide natural circulation cooling if offsite power is lost. Can flood if necessary, but may not help depending on location of tube failure, cannot flood to where level may impact the turbine driven pump. No further action is required. Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k and only a fraction of this benefit would be achieved if this suggestion were implemented. Since the assessed benefit is much less than the estimated cost this suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
88	Implement a maintenance practice that inspects 100% of the tubes in a steam generator	<$11k	>2 x Benefit	Screen out	<$22k	<=$13.3k	<$11.4k	<$16.2k	<$5.8k	Analysis case NOSGTR determined that the benefit of eliminating all SGTR is <$11k (and not all tube ruptures would be eliminated by expanding the inspection scope). The costs required to implement this suggestion are therefore judged to be significantly greater than the benefit achieved. (Estimated cost $1.5M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
89	Locate RHR inside of containment	<$1.6k	>2 x Benefit	Screen out	<$3.2k	<=$2k	<$1.7k	<$2.4k	<$0.9k	Per the ANO-1 PSA (Analysis case ISL) minimal benefit is attainable even if the proposed change were assumed to reduce the ISLOCA frequency to zero (approximately $1600). Since the cost of the proposed modification is many orders of magnitude greater than the assessed benefit, the proposed SAMA is screened out. Not cost-beneficial; cost is expected to exceed twice the benefit.
90	Provide self-actuating containment isolation valves	<$22.2K	>2 x Benefit	Screen out	<$44.4k	<=$22.2 K	<$22.2k	<$31.1k	<$13.1k	The maximum benefit obtained by totally eliminating offsite release is $22.2k (with no core damage reduction). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
92	Increase frequency of valve leak testing	<$0.2.k	>2 x Benefit	Screen out	<$0.4k	<=$0.2.k	<$0.2k	<$0.3k	<$0.1k	Since ANO-1 has pressure detectors between the first two pressure isolation valves for the dominant ISLOCA scenarios (see #91 above), it is judged that ISLOCA frequency would not be significantly reduced by the proposed modification. Therefore the benefit of the suggested modification is estimated as less than 10% of a change which would eliminate ISL scenarios. The value of the change is then estimated as less than $160 (10% of the benefit from analysis case ISL). Since the cost of increased testing is much more than the assessed benefit the suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
93	Improve operator training on ISLOCA coping	<$1.6k	>2 x Benefit	Screen out	<$3.2k	<=$2k	<$1.7k	<$2.4k	<$0.9k	Per analysis case ISL the risk benefit attainable if the ISLOCA CDF is reduced to zero is approximately $1600. Since the preparation and implementation of additional ISLOCA training would cost much more than the estimated benefit this suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
94	Install relief valves in the ICW system	<$0.2k	>2 x Benefit	Screen out	<$0.3k	<=$0.2k	<$0.2k	<$0.2k	<$0.1k	This scenario was estimated as 3E-9 contributor to core damage and containment bypass core damage in the ANO-1 ISLOCA analysis. The value of the change is estimated as a 6.7% reduction in ISLOCA frequency. Per the ANO-1 PSA (analysis case ISL) the value of the risk reduction is estimated as approximately $103 (0.067*$1600). Since the cost of the proposed modification is much greater than the assessed benefit, the proposed modification was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
95	Provide leak testing of valves in ISLOCA paths	<$1.6k	>2 x Benefit	Screen out	<$3.2k	<=$2k	<$1.7k	<$2.4k	<$0.9k	Per analysis case ISL the risk benefit attainable if the ISLOCA CDF is reduced to zero is approximately $1600. Since the preparation and implementation of additional ISLOCA training would cost much more than the estimated benefit this suggestion was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
96	Revise EOPs to improve ISLOCA identification	<$1.6k	>2 x Benefit	Screen out	<$3.2k	<=$2k	<$1.7k	<$2.4k	<$0.9k	Per the ANO-1 PSA (analysis case ISL) minimal benefit is attainable even if the training/procedure change were assumed to reduce the ISLOCA frequency to zero (approximately $1600). Therefore the proposed suggestion is screened out as not cost-effective. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
97	Ensure all ISLOCA releases are scrubbed	<$1.6k	>2 x Benefit	Screen out	<$3.2k	<=$2k	<$1.7k	<$2.4k	<$0.9k	Analysis case ISL determined the benefit of eliminating all ISLOCA to be $1,600. The costs of the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
98	Add redundant and diverse limit switch to each containment isolation valve.	<$24k	>2 x Benefit	Screen out	<$48k	<=$24.2k	<$23.9k	<$33.4k	<$13.9k	The maximum benefit obtained by totally eliminating offsite release is $22.2k (with no core damage reduction, $24K if ISLOCA frequency was assumed to be significantly decreased; see analysis case ISL). The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. (Estimated cost $1M (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
107	Install digital feedwater upgrade	<$4.1k	>2 x Benefit	Screen out	<$8.2k	<=$6.7k	<$4.6k	<$6.8k	<$1.8k	Analysis case FW determined the benefit of eliminating all feedwater initiators (Loss of power conversion system and excessive feedwater flow) to be <$4.1k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
114	Provide portable generators to be hooked in to the turbine driven AFW, after battery depletion	<$2.3k	>2 x Benefit	Screen out	<$4.6k	<=$3k	<$2.4k	<$3.5k	<$1.2k	Analysis case PDSTDPDC estimated the risk reduction benefit of this suggested change as <$2.3k. Station Blackout is already a negligible contributor to ANO-1 core damage risk due to installation of a diverse backup DG. Since the cost of the suggested change is judged to be much greater than the assessed benefit the change was screened out from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
115	Add a motor train of AFW to the steam trains.	<MAB	>2MAB	Screened out	<MAB	<MAB	<MAB	<MAB	<MAB	Cost of adding another motor driven AFW train would be expected to exceed 2 MAB. ANO-1 already has a motor driven pump in combination with a turbine driven pump. Not cost-beneficial; cost is expected to exceed twice the benefit.
121	Create passive secondary side coolers	<MAB	>2MAB	Screened out	<MAB	<MAB	<MAB	<MAB	<MAB	The maximum benefit for reducing core damage to zero is $145.4k. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
124	Provide an additional high pressure injection pump with independent diesel	<$61.1k	>2 x Benefit	Screen out	<$122.2k	<=$95.2k	<$67.9k	<$99.8k	<$27.5k	Review of the ANO-1 PSA results indicates that 5.52E-6/yr of the total CDF could potentially be averted if a perfect HPI system reliability could be achieved. However 2.48E-6 of the 5.52E-6 HPI core damage is due to total loss of service water. Even if the diverse HPI pump were independent of SW cooling, SW cooling is required for recirculation (DHR HX cooling and cooling to the LPI pumps) therefore these sequences will still result in core damage unless SW is eventually recovered. Assuming 50% of SW faults are recovered prior to core damage the decreased core damage from a perfect HPI system is estimated as 4.28E-6 (3.04E-6 + 0.5 * 2.48E-6) which represents a 42% reduction in CDF. The value of the proposed modification is then estimated as 42% of the MAB ($145.4K) or as $61k which is much less than the estimated cost of the modification. (Estimated cost $2.2M (System 80+), $3.5M (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.
125	Install independent AC high pressure injection system	<$61.1k	>2 x Benefit	Screen out	<$122.2k	<=$95.2k	<$67.9k	<$99.8k	<$27.5k	Review of the ANO-1 PSA results indicates that 5.52E-6/yr of the total CDF could potentially be averted if a perfect HPI system reliability could be achieved. However 2.48E-6 of the 5.52E-6 HPI core damage is due to total loss of service water. Even if the diverse HPI pump were independent of SW cooling, SW cooling is required for recirculation (DHR HX cooling and cooling to the LPI pumps) therefore these sequences will still result in core damage unless SW is eventually recovered. Assuming 50% of SW faults are recovered prior to core damage the decreased core damage from a perfect HPI system is estimated as 4.28E-6 (3.04E-6 + 0.5 * 2.48E-6) which represents a 42% reduction in CDF. The value of the proposed modification is then estimated as 42% of the MAB ($145.4K) or as $61k which is much less than the estimated cost of the modification. Not cost-beneficial; cost is expected to exceed twice the benefit.
129	Emphasize timely recirc swapover in operator training	<$47.2k, possibly as low as <$31.5k	<2 x Benefit	This SAMA does not screen out.	<$94.4k, possibly as low as <$62.9k	<$77.2k, possibly as low as <$51.5k	<$53.2k, possibly as low as <$35.5k	<$78.7k, possibly as low as <$52.5k	<$20.3k, possibly as low as <$13.6k	Per analysis case PDSHPROA the benefit of a change that reduced the human error probability for recirculation to zero was estimated as $47.2k. If increased training is assumed to reduce the human error probability by a factor of 3, then the benefit of increased training would be estimated as $31.5K (47.2k * 2/3). The proposed suggestion does not screen out.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
138	Create automatic swapover to recirculation on BWST depletion	<$47.2k	>2 x Benefit	Screen out	<$94.4k	<=$77.2k	<$53.2k	<$78.7k	<$20.3k	Per analysis case PDSHPROA the benefit of this proposed modification was estimated as $47.2k. The engineering, procurement and installation of controls to automate the swapover of BWST to recirc from the sump would include BWST level monitors, ESFAS upgrade and interlock controls on sump and BWST valves. These changes in addition to operational procedure changes and training would well exceed 2 X $47.2k (assume internal and external effects). No cost estimate needed. Not cost-beneficial; cost is expected to exceed twice the benefit.
139	Modify EOPs for ability to align diesel power to more air compressors.	<$2.5k	>2 x Benefit	Screen out	<$5k	<=$3.1k	<$2.6k	<$3.7	<$1.3k	Analysis case INSTAIR2 removed all power dependencies/support for the air compressors. The benefit was determined to be <$2.5k. The costs of the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
140	Replace old air compressors with more reliable ones.	<$3.4k	>2 x Benefit	Screen out	<$6.8k	<=$4.1k	<$3.5k	<$5k	<$1.8k	Analysis case INSTAIR1 determined the benefit of perfectly reliable air compressors to be <$3.4k. The costs of the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
142	Install MG set trip breakers in control room	<$8.1k	>2 x Benefit	Screen out	<$16.2k	<=$12.6k	<$9k	<$13.2k	<$3.7k	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1k [145.4K (MAB) * 5.7E-7/1.027E-5]. Since ANO-1 ATWS risk is dominated by mechanical failures of the rods rather than by electrical failure, the proposed modification would provide only a fraction of this benefit. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
143	Add capability to remove power from the bus powering the control rods	<$8.1k	>2 x Benefit	Screen out	<$16.2k	<=$12.6k	<$9k	<$13.2k	<$3.7k	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1k [145.4K (MAB) * 5.7E-7/1.027E-5]. Since ANO-1 ATWS risk is dominated by mechanical failures of the rods rather than by electrical failure, the proposed modification would provide only a fraction of this benefit. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. (Estimated cost $143k (TVA)). Not cost-beneficial; cost is expected to exceed twice the benefit.
147	Add a system of relief valves that prevents any equipment damage from a pressure spike during an ATWS	<$8.1k	>2 x Benefit	Screen out	<$16.2k	<=$12.6k	<$9k	<$13.2k	<$3.7k	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1K [145.4K (MAB) * 5.7E-7/1.027E-5]. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
148	Create a boron injection system to back up the mechanical control rods.	<$8.1k	>2 x Benefit	Screen out	<$16.2k	<=$12.6k	<$9k	<$13.2k	<$3.7k	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1K [145.4K (MAB) * 5.7E-7/1.027E-5]. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.
149	Provide an additional I&C system (e.g., AMSAC).	<$8.1k	>2 x Benefit	Screen out	<$16.2k	<=$12.6k	<$9k	<$13.2k	<$3.7k	The ATWS contribution in Revision 1 to the ANO-1 PSA is 5.7E-7. If the ATWS CDF could be entirely eliminated by the proposed modification it would have an estimated value of approximately $8.1K [145.4K (MAB) * 5.7E-7/1.027E-5]. Since ANO-1 ATWS risk is dominated by mechanical failures of the rods rather than by electrical failure, the proposed modification would provide only a fraction of this benefit. Since the proposed modification would cost much more than the assessed benefit, the modification was screened from further consideration. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3 Sensitivity Analysis Results

SAMA Number	Potential Improvement	Benefit (Bounding)	Estimated Cost[5]	Conclusion	Benefit (External Events Sensitivity) (Bounding)	Benefit (Replacement Power Sensitivity) (Bounding)	Benefit (Repair/ Refurbishment Sensitivity) (Bounding)	Benefit (3% Discount Rate Sensitivity) (Bounding)	Benefit (15% Discount Rate Sensitivity) (Bounding)	Basis for Conclusion
151	Create/enhance reactor coolant system depressurization ability	<$6.4k	>2 x Benefit	Screen out	<$12.8k	<=$7.9k	<$6.7k	<$9.5k	<$3.4k	Analysis case PDSRCD evaluated the benefit attained if perfect depressurization capability is provided to be $6.4k. (Since ANO-1has high head ECCS pumps, depressurization is only required for SGTR sequences). Since the cost of the proposed change would cost much more than the assessed benefit the change is screened out from further consideration. (Estimated cost for new system $4.6M (TVA), $500k to enhance existing system (System 80+)). Not cost-beneficial; cost is expected to exceed twice the benefit.
152	Make procedural changes only for the RCS depressurization option	<$6.4k	>2 x Benefit	Screen out	<$12.8k	<=$7.9k	<$6.7k	<$9.5k	<$3.4k	A sensitivity run assuming perfect depressurization capability indicates that negligible value (<$6.4k) is attained by revising the SGTR procedure to credit additional depressurization methods (see #151, case PDSRCD). Therefore the cost of a significant EOP change is not justified by the risk reduction attained. Not cost-beneficial; cost is expected to exceed twice the benefit.
155	Add secondary side guard pipes up to the MSIVs.	~$0	>2 x Benefit	Screen out	~$0	~$0	~$0	~$0	~$0	Analysis case NOSLB determined the benefit of eliminating all steam/feedwater line breaks to be negligible. Since the cost of the proposed change is much greater than the risk reduction benefit attained the suggestion was screened out from further consideration. (Estimated cost $1.1M (System 80)). Not cost-beneficial; cost is expected to exceed twice the benefit.
156	Add digital large break LOCA protection	<$43.6k	>2 x Benefit	Screen out	<$87.2k	<=$71.5k	<$49.2k	<$72.8k	<$18.7k	Analysis case NO-A determined the benefit of eliminating all Large Break LOCA initiators to be $43.6K. The costs associated with the plant modifications required to implement this alternative are judged to be significantly greater than this amount even without a specific cost estimate. Not cost-beneficial; cost is expected to exceed twice the benefit.
157	Increase seismic capacity of the plant to a HCLPF of twice the SSE	<MAB	>2 MAB	Screen out	<MAB	<MAB	<MAB	<MAB	<MAB	The benefit achieved is estimated as less than the ANO-1 MAB of $145.4K. (Seismic CDF is judged to have a CDF significantly less than the internal CDF). ANO-1 has performed an analysis to determine that the existing plant design (SSE = 0.2g) is adequate for a 0.3g earthquake. This analysis cost ~$750k. It is expected that significant plant modifications would be necessary to increase the capacity to 0.4g and that the cost would greatly exceed 2MAB. Not cost-beneficial; cost is expected to exceed twice the benefit.

G.3 ACRONYMS USED IN ATTACHMENT G

AAC	Alternate Alternating Current
ABB	Asea Brown Boveri, Inc.
AC	Alternating Current
ADS	Automatic Depressurization System
AFW	Auxiliary Feedwater
AFWST	Auxiliary Feedwater Storage Tank
AMSAC	ATWS Mitigating System Actuation Circuitry
ANO-1	Arkansas Nuclear One Unit 1
AOV	Air Operated Valve
ATWS	Anticipated Transient Without Scram
B&W	Babcock and Wilcox
BGE	Baltimore Gas and Electric Company
BWR	Boiling Water Reactor
BWST	Borated Water Storage Tank
CCNP	Calvert Cliffs Nuclear Plant
CCW	Component Cooling Water
CDF	Core Damage Frequency
CE	Combustion Engineering
CRD	Control Rod Drive
CST	Condensate Storage Tank
CV	Control Valve
CVCS	Chemical and Volume Control System
DC	Direct Current
DG	Diesel Generator
DHR	Decay Heat Removal
ECCS	Emergency Core Cooling System
EFIC	Emergency Feedwater Initiation and Control
EFW	Emergency Feedwater
EOP	Emergency Operating Procedure
ERCW	Emergency Raw Cooling Water
FW	Feedwater
HCLPF	High Confidence of Low Probability of Failure
HPCI	High Pressure Coolant Injection
HPCS	High Pressure Core Spray
HPI	High Pressure Injection
HPSI	High Pressure Safety Injection
HR	Heat Removal
HVAC	Heating, Ventilation and Air Conditioning
I&C	Instrumentation and Control
ICONE	International Conference on Nuclear Engineering
ICW	Intermediate Cooling Water
IPE	Individual Plant Examination
ISLOCA	Interfacing System LOCA

KV	Kilo-Volts
LOCA	Loss of Coolant Accident
LOP	Loss of Power
LOSW	Loss of Service Water
LPCI	Low Pressure Coolant Injection
LPI	Low Pressure Injection
LPSI	Low Pressure Safety Injection
MAB	Maximum Attainable Benefit
MCC	Motor Control Center
MD	Motor Driven
MFW	Main Feed Water
MG	Motor Generator
MOV	Motor Operated Valve
MSIV	Main Steam Isolation Valve
NRC	Nuclear Regulatory Commission
PC	Plant Change
PMP	Probable Maximum Precipitation
PORV	Power Operated Relief Valve
PRA	Probabilistic Risk Analysis
PRT	Pressurizer Relief Tank
PSA	Probabilistic Safety Assessment
PWR	Pressurized Water Reactor
RAI	Request for Additional Information
RB	Reactor Building
RCIC	Reactor Core Isolation Cooling
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RV	Relief Valve
S/G	Steam Generator
SAMA	Severe Accident Mitigation Alternative
SAMDA	Severe Accident Mitigation Design Alternative
SAMG	Severe Accident Management Guideline
SBO	Station Blackout
SI	Safety Injection
SGTR	Steam Generator Tube Rupture
SLC	Standby Liquid Control
SRV	Safety Relief Valve
SSE	Safe Shutdown Earthquake
SW	Service Water
TD	Turbine Driven
TDP	Turbine Driven Pump
TVA	Tennessee Valley Authority
V	Volts
WBN	Watts Bar Nuclear Plant